Modeling the Constant Composition Expansion Test of Black Oil using Pressure, Volume, and Temperature (PVT) Calculations

By Peter Sydney Aprioku, Godsday Idanegbe Usiabulu, Ifeanyi Eddy Okoh, Idorenyin Isim Uboh & Prisca Kanebi

University of Port Harcourt

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. Four sets of black oil samples were collected for the analysis. The black oil standard test is a constant composition expansion test (CCE) separator flash test for volatile oils and rich oil gas condensate and a constant volume depletion test (CVD). 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 res. Bbl/STB while standing correlations give (B_o) of 1.0675 res bbl/STB a difference of 3.6%.

Keywords: isothermal pressure, volume, temperature, constant composition expansion, black oil.

GJRE-J Classification: LCC: TN871.2

MODELINGTHECONSTANTCOMPOSITIONEXPANSIONTESTOFBLACKOILUSINGPRESSUREVOLUMEANDTEMPERATUREPVTCALCULATIONS

Strictly as per the compliance and regulations of:

Modeling the Constant Composition Expansion Test of Black Oil using Pressure, Volume, and Temperature (PVT) Calculations

Peter Sydney Aprioku [α], Godsday Idanegbe Usiabulu [σ], Ifeanyi Eddy Okoh [ρ], Idorenyin Isim Uboh [ω] & Prisca Kanebi [¥]

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. Four sets of black oil samples were collected for the analysis. The black oil standard test is a constant composition expansion test (CCE) separator flash test for volatile oils and rich oil gas condensate and a constant volume depletion test (CVD). 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 res. 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 10.12×10^{-6} psi^{-1} at $P < P_b$ (at 4500 psi) to 4.1309×10^{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 high pressure of 4500 psig the black oil viscosity was as low as 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.

Keywords: isothermal pressure, volume, temperature, constant composition expansion, black oil.

I. Introduction

During the development of oil and gas fields, the fluid produced is subjected to several conditions. As they travel from the reservoir, up to the pipelines, and then through surface facilities, the system's pressure, and temperature change (Cosse, 1993). Along this process, the fluid composition, oil and gas volumes, and fluid properties such as density and viscosity will also vary.

To study how these volumetric changes will occur, several laboratory experiments are routinely conducted with reservoir oil samples in a PVT cell, reproducing the conditions that the fluids are subjected to during production (Whitson, 1981). The most common PVT test performed to characterize this reservoir fluid is constant composition Expansion. Petroleum (an equivalent term is crude oil) is a complex mixture consisting predominantly of hydrocarbons and containing sulfur, nitrogen, oxygen, and helium as minor constituents. The physical and chemical properties of crude oils vary considerably and depend on the concentration of the various types of hydrocarbons and minor constituents present (Cosse, 1993). Crude oil reservoirs are classified according to initial reservoir pressure into the following categories:

1) Under a saturated oil reservoir; in which initial reservoir pressure is greater than the bubble point pressure of reservoir fluid
2) Saturated oil reservoir; in which initial reservoir pressure is equal to the bubble point pressure of reservoir fluid
3) Gas-cap reservoir; in which initial reservoir pressure is below the bubble point pressure of

A reservoir fluid, so reservoir is termed a gas-cap or two-phase reservoir since the gas or vapor phase is underlain by an oil phase. Petroleum hydrocarbons exist as gaseous or liquid phases depending on reservoir temperature. If it is higher than the critical temperature of the fluid, the reservoir fluid is gas (Whitson, 1981). Otherwise, the reservoir fluid is oil. The black oil reservoir is considered as one of the most precious reservoir fluids. It constitutes many oil reservoirs and exists in every basin. An accurate description of the physical properties of crude oils is of considerable importance in the fields of both applied and theoretical science and, especially, in the solution of petroleum reservoir engineering problems. Some of these physical properties are of primary interest in petroleum engineering studies and detected through PVT tests which aim to determine reservoir fluid behavior

Author α: Department of Chemical/Petrochemical Engineering, Rivers State University, Nkpolu, Port Harcourt, Nigeria.
e-mail: aprioku@yahoo.com
Author σ: World Bank, Africa Center of Excellence, Center for Oil Field Chemicals Research, University of Port Harcourt, Choba, Port Harcourt, Nigeria. e-mail: godsdayusiabulu@gmail.com
Author ρ: First Hydrocarbon Nigeria (FHN) 26 Limited - First Hydrocarbon Block W Shell Estate Edjeba, Delta State, Nigeria.
e-mail: eddymario2006@yahoo.com
Author ω: Dodageo Integrated Energy Limited, Nigeria. 35 Chief Nwuke Street, Trans Amadi Industrial Layout, Port Harcourt, Nigeria.
Author ¥: The Nigerian Institution of Petroleum Engineers (A Division of The Nigeria Society of Engineers) Lagos State, Nigeria.

at simulated reservoir conditions. Data on these fluid properties is usually determined by the laboratory (Vasquez and Beggs, 1987).

Experiments were performed on samples of actual reservoir fluids. In the absence

For experimentally measured properties of crude oils, it is necessary for the petroleum engineer to determine the properties from empirically derived correlations. However, correlations are approximations and may be useful only in regional geological provinces.

Crude oils cover a wide range of physical properties and chemical compositions and are classified into black oils and near-critical or volatile-oils depending on their phase behavior (Moses, 1986).

The aims and objectives of this research work is to validate PVT parameters in a saturated black oil reservoir using Correlation. This research work will cover basic PVT parameters such as oil formation volume factor (B_o), solution gas/oil ratio (R_{so}), oil compressibility factor (Co), Oil viscosity (μ_o), and liquid/gas ratio of vapour phase (RV) (Tariq et al., 2021).

This research work will not cover the general PVT report as in analysis of constant composition expansion test (CCE).

Oil prospecting is a high-risk business and as such thorough investment decisions must be based on quantifiable and verifiable facts. PVT analysis is a tool that helps bring to the fore the likelihood of recoverable hydrocarbon fluids in a reservoir before proper capital mobilization and infrastructure planning can be made for the reservoir (Hemmati, 2016). The final investment decision is needed for any oil reservoir development to commence but this decision cannot be made if the reservoir has not been economically evaluated and PVT studies offers a good platform to economically evaluate the reservoir (Fattah and Lashin, 2018). According to Standing, (1947) the PVT analysis helps in properly guiding the planning and installation of the production and transportation facilities for any producing reservoir. (Standing, 1947).

PVT studies also acquaint us with the volume of gas that is dissolved in the crude and API gravity of crude oil so that gas facilities and pipelines can be designed for that reservoir. This is because every reservoir is unique, so the uniqueness of each reservoir must be established by using the PVT analysis. PVT studies are highly desirable to properly evaluate crude oil reservoirs (Udegbunam and Owolabi, 1983).

II. Materials and Method

a) Materials

Most of the experiments and measurements in this chapter are carried out using RUSKA instruments (Note: RUSKA is an American Engineering firm that manufactures high precision instrument for measuring reservoir fluid properties). RUSKA research precision instruments when properly calibrated, can measure fluid properties to + 0.01 percent accuracy. The three main parameters measured are pressure, volume, and temperature of the reservoir fluid (Tohidi-Hosseini, 2016).

The RUSKA dead weight gauge or the Heise gauge is used to measure pressure. RUSKA gasometer is used to measure gas volume, RUSKA visual liquid phase PVT cell is used to carry out PVT experiment, pod distillation column is used for low temperature distillation of the reservoir fluid, temperature (Jones and Roselle, 1978). Other equipment and accessories used in the analysis are viscometer, barometer, mercury pumps, gas chromatograph, and low- and high-pressure gauges. The key material for analysis is a "sample" of reservoir fluid, and the different sampling techniques of the reservoir fluid are discussed below. (Fattah and Lashin, A. 2018).

b) Method

- Sampling of Reservoir Fluid

There are basically two ways of collecting oil sample from a reservoir.

i. Direct subsurface sampling, and
ii. Surface separator sampling, followed by recombination of oil and gas phases to produce the desired gas/oil ratio. Whichever, technique is used, the same basic problem exist; that is, to ensure that the ratio of gas-to-oil in the composite sample is the same as that existing in the reservoir.

Conditioning a well is a prerequisite in obtaining a representative fluid sample from the well. Well conditioning is the process whereby the well is produced for a sufficient length of time by flowing the well through test separator for about 24 hours or more to bring about stable condition, with an opening (choke size) small enough not to cause appreciable pressure drop in the vicinity of the well bore but large enough to clean out mud filtrate and liquid accumulation in the tubing (Mahdiani and Kooti, 2016). Well conditioning is most critical when the reservoir fluid is saturated (that is, the oil and gas phase co-exist is the reservoir pressure and temperature). A reduction in pressure around the well bore, which occurs as the well is being produced, alters the composition of the fluid before it enters the well bore; the objective of well conditioning is to remove this altered fluid in and around the well bore, by replacing it with a representative or unaltered fluid from the formation.

The following general facts should be noted when obtaining a representative reservoir fluid sample for laboratory studies:

1. There is no assurance that any sample obtained from one well is representative of the fluid throughout the reservoir.

2. There composition of the fluid can vary due to gravity segregation in thick pay zones or due to movement of fluid from different formations (fractures, faults) to form the same reservoir with the same structural elevation over geologic times.
3. Sufficient number of samples should be taken from different wells soon after discovery of the reservoir. This will define the average fluid properties of the reservoir.
4. Complete analysis of all the samples taken may not be necessary.

• *Subsurface or Bottom Hole Sampling*

Since there is pressure drop as a result of flowing a well for a considerable period of time (24 hours or more) during well conditioning, it is necessary to shut in the well after conditioning for pressure to build up to the reservoir pressure before taking sample. In most cases, bottom hole sampling is always associated with pressure measurements in the well to estimate the bubble point at various depths, often prior to sampling. If the well has been shut in for a long time and the pressure at the lowest oil level in the well is above estimated bubble point pressure, the well should be flowed at a "bleed" rate to introduce fresh reservoir fluid into the well bore. If the pressure is close to the bubble point pressure, the well should be shut in for sampling. If the estimated bubble-point pressure at the lowest oil level is above the existing pressure at that point, the use of another well must be considered because sample taken from such well will not be representative of the reservoir fluid (Kanu and Ikiensikimama, 2014). If

sample taken from such well will not be representative of the reservoir fluid. If the well is making any water-cut during production, the well should be shut in and tested for water.

The best place to obtain the sample is the lowest point in the well bore with uniform pressure gradient. To identify this point, a pressure gradient is run just prior to sampling. The oil pressure gauge is lowered to perforation, if possible, to record present bottom hole pressure and temperature. These pressures are translated to pressure gradients and the gradients plotted as a function of depth. Oil gradients vary from 0.2 psilft to 0.38 psi/ft for high gas content to low gas content crude respectively (Mahdiani and Kooti, 2016). The water level is located by plotting pressure gradient against depth. The oil-water contact is at the depth where the gradient changes from one representative of the oil to that of water (water gradient is about 0.4 psi/fl or greater). The sampling point should be picked at about 50 feet above the oil-water contact point if this point is well defined on the plot. If the contact point is not well defined, the sampling point should be picked from the lowest oil level with a defined pressure reading. The sampler shown in Appendix B (Fig. B 1) is prepared and run into the hole (borehole) on wire line to the reservoir depth as shown in Fig. B2, and a sample of the reservoir fluid is collected from the subsurface well stream at the prevailing bottom hole pressure (Mahdiani and Kooti, 2016). Details of the preparation of the sampler and sampling procedure are given below (Reservoir Fluids Laboratory Nigeria Limited).
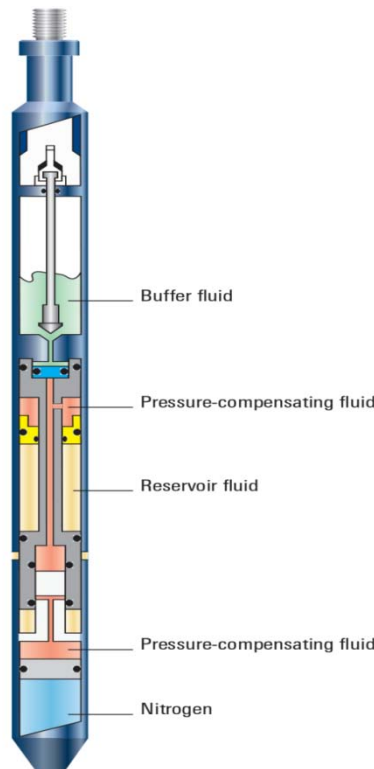

Figure 1: Diagram showing a bottom hole sampler (Mahdiani and Kooti, 2016)

- *The Advanced System for all your Subsurface Sampling Applications*

The single-phase reservoir sampler (SRS) is a specialized system that maintains the sample in a single-phase condition above reservoir pressure as the tool is retrieved from the hole. This reliable technology provides truly representative samples—which is essential for measurements requiring samples in unaltered conditions, such as pressurized pH measurements in formation water or asphaltene deposition analysis in oil.

Regardless of your sampling application, the SRS enables controlled, uncontaminated reservoir sampling without sample flashing. The unaltered sample is retrieved at the surface in its single-phase state, requiring no recombination before transfer. Eliminating sample recombination at the surface means your sample transfer takes only minutes instead of hours. The mercury-free, pressure-compensating SRS can be run in strings of up to eight tools on slickline, wireline, or electric line, coiled tubing, or sucker pump rods (Hashemi et al., 2020). Each SRS has its clock, giving you complete flexibility in deciding when and at what depth it takes a sample.

- *Summary of Bottom Hole Sampling*

i. Check the operation of the sampler and tools before leaving for the field.
ii. Pressure gradient should be run before sampling.
iii. Preferably, the well should be shut in while sampling.
iv. When sampling with a clock system, leave the sampler in the hole for at least 10 minutes past the set time.
v. Make sure two samples from the same point have the same bubble point pressure.
vi. Shear-pin method should only be used if there is an uncorrectable failure of clock systems in the field.

- *Surface Sampling*

Here, separator oil and gas samples are taken separately. The method employed in sampling separator oil is the method of displacement, where the separator oil displaces a mixture of glycol and water in a cylinder (Hashemi et al., 2020). The objective of this method is to obtain a sample of the separator oil with no loss of dissolved gas or contaminating gas. The general procedure for obtaining separator oil and gas samples is as follows:

i. Connect sampling lines (tubing) from the separator gas outlet to a gas cylinder and from the oil outlet to an oil cylinder (the gas cylinder is prepared by vacuuming, while the oil cylinder is prepared by filling the cylinder with a mixture of glycol and water).
ii. Open the separator outlet valve to fill the sampling lines.
iii. Check for leakages

iv. Open the cylinder inlet valve for filling
v. Then shut and isolate the cylinder after filling
vi. Disconnect the cylinders and lines from the separator
vii. Label the cylinders appropriately.

c) *Quality Check*

All black oil samples arriving in the laboratory from the field after sampling are kept in a single phase by compressing them to at least 2000psi above reservoir pressure and subjected to quality check before deciding on which sample or set of samples to use for analysis.

- *Subsurface Samples*

All subsurface samples are heated to the temperature condition in the reservoir, and bubble-point pressure is determined in the laboratory and compared to field bubble-point pressure. A portion of the sample is also "flashed" and the liberated gas is run through gas chromatograph to determine any air contamination (Hashemi et al., 2020). (Note: flash in this context means the process of passing a portion of the oil from a condition of higher pressure and temperature to a condition of lower pressure and temperature so as to liberate gas from solution). The sample with the least or no contamination and a representative bubble-point pressure is picked for the study. For bottom hole gas samples, flashing and contamination checks are made to determine the most representative sample.

- *Surface Sample*

Surface samples consist of separator gas and oil. In the case of separator gas, the sample bottles are put into an oven at separator temperature for at least two hours. The opening pressure of each cylinder is checked against the separator pressure and the gas is characterised by passing it through gas chromatograph to obtain its composition up to C7+ (heptene plus), and to determine any air contamination. The sample with the least contamination and a pressure equal to the separator pressure is picked for study.

For the separator oil, a portion of the oil sample is transferred to a PVT cell at separator temperature, and the bubble-point pressure is determined (later explained in detail). A portion of the separator oil is later flashed from separator condition to atmospheric condition to determine shrinkage, and the gas from the flash is analysed to obtain the level of air contamination (Foster and Beaumont, 1987).

- *Summary of Quality Check on Subsurface and Surface Oil Sample*

Bottom hole samples are brought to the laboratory and their bubble-point determined at either room or reservoir temperature. The values are compared with the field data and the most representative sample is chosen. The composition of the

sample is determined by low temperature distillation (Foster and Beaumont, 1987).

Surface separator samples are brought to the laboratory after sampling from the field; the separator gas composition is analysed by gas chromatograph. The bubble-point pressures of the duplicate or triplicate samples are determined for the separator oil. These values are compared with the field data of the samples and the most representative sample is chosen and is composition is determined by low temperature distillation. (Udegbunam and Owolabi, 1983).

d) Recombination Calculation

Separator oil and gas samples from the field after passing through the quality-control test in the laboratory have to be recombined to the initial producing gas/oil ratio as follows (Moses, 1986).

$$G_{CC} = \frac{G}{5.61458} \qquad 3.1$$

$$\text{Actual pump volume of oil required} = \frac{0.99928VK'}{G_{CC}S} \qquad 3.2$$

Where

S	=	Oil shrinkage factor
V	=	Volume of gas in the cell, cm³
G	=	Producing gas/oil ratio, SC F/STB
G_{CC}	=	Producing gas/oil ratio, cm³/cm³
K′	=	Gas expansion factor

III. Laboratory Experiment

a) Constant Mass or Constant Composition Expansion

This experiment is carried out at the reservoir temperature using sample 2 and the results obtained are shown in table 1.

Pressure (psig)	Relative volume (V/V_sat)	Y-function $\dfrac{P_{sat} - P}{P((V/V_{sat})-1)}$	Liquid Phase Viscosity (cp)
4500	0.9730		0.5400
4000	0.9794		0.5200
3500	0.9851		0.5000
3000	0.9916		0.4800
2575	0.9964		0.4630
2435	1.0000		0.4600
2000	1.0820	2.6530	0.5000
1600	1.2174	2.4000	0.5600
1200	1.4796	2.1460	0.6300
800	2.0796	1.8930	0.7500
400	4.1021	1.6400	0.9200
100	17.1034	1.4500	1.2500
15	-	-	1.3800

Source: Reservoir Fluid Laboratory Port Harcourt

b) Constant Composition Expansion (CCE)

The CCE experiment also is called the Constant Mass Expansion (CME) or simply a pressure volume (PV) test is performed on black oil.

The CCE experiment is used to determine bubble-point pressure, undersaturated oil density, isothermal oil compressibility, and two-phase volumetric behaviour at pressure below the bubble-point pressure at reservoir temperature. A RUSKA visual PVT cell is filled with a known mass of reservoir fluid. The sample is initially brought (compressed) to a condition somewhat above initial reservoir pressure ensuring that the fluid is single-phase. The pressure is then decreased in steps by reducing the mercury level in the cell to attain equilibrium and the corresponding volume of the oil at each step is recorded after sufficient agitation as shown in fig. C2 showing the various steps of the CCE experiment (Foster and Beaumont, 1987). To prevent the phenomenon of super saturation or meta-stable equilibrium where a moisture remains as a single phase even though it is below the bubble-point obtained from the quality check (Standing, 1947). The actual bubble-point pressure is obtained by plotting the recorded cell volume against the corresponding pressure, and the point of intersection of the P-V trends in the single and two-phase regions gives the bubble point pressure and volume as shown in Fig. C3. However, in the visual PVT cell (with a glass window), the bubble-point (corresponding to the first bubble of gas that evolves) could actually be observed.
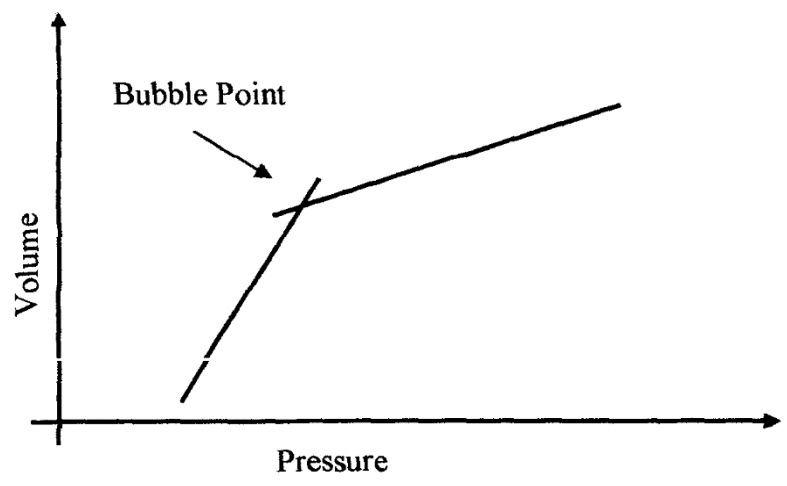
Figure B3: Determination of Bubble point CCE experiment (Foster and Beaumont, 1987)

Table 3: Separator test data of the reservoir fluid at 106°F

Pressure PSIG	Separator gas/oil ratio SCF/STB	Stock tank oil/gas ratio SCF/STB	Total gas/oil ratio SCF/STB	Formation volume factor Bosp	Stock tank oil O_{API}	Separator gas gravity $\gamma_g$sp	Stock tank gas gravity
400	551	232	783	1.456	30	0.698	1.306

Table 4: PVT data for the separator flash analysis at flash conditions

P(PSTg)	TR (OF)	RS	γ_oAPI	B_oF_b	γg
400	106	783			0.698
200	75	759	30	1.456	0.744
0	75	919			0.808

IV. Results and Discussion

Analysis of Results/Discussion

a) *Corrected Parameters from PVT Report*

The following equations are used to validate the correct PVT parameters from a PVT report:

$$R_SF \quad = \quad \frac{R_{SF_b}}{R_Sdb} \times R_Sd$$

$$B_OF \quad = \quad \frac{R_{OF_B}}{B_Odb} \times R_Od$$

Where

R_SF	=	Solution gas/oil ratio at flash conditions
R_SFb	=	Solution gas/oil ratio at flash bubble point
R_sdb	=	Solution gas/oil ratio at differential condition
B_OF	=	Oil formation volume factor at flash condition
B_OFb	=	Oil formation volume factor at different bubble point
B_sd	=	Oil formation factor at differential condition
P_b	=	2000Psi, R_sFb = 783 SCF/STB, R_sdb = 83/SCF/STB
R_sd	=	687SCF/STB

at $P \leq P_b$

at 2000Psi

$$R_S F = \frac{783}{831} \times 687$$

$$= 647.3 \text{ SCF/STB}$$

at 16000Psi

$$R_S F = \frac{783}{831} \times 561$$

$$= 528.6 \text{ SCF/STB}$$

at 1200Psi

$$R_S F = \frac{783}{831} \times 442$$

$$= 416.5 \text{ SCF/STB}$$

at P = 800Psi

$$R_S F = \frac{783}{831} \times 331$$

$$= 311.9 \text{ SCF/STB}$$

at P = 400Psi

$$R_S F = \frac{783}{831} \times 214$$

$$= 201.6 \text{ SCF/STB}$$

at P = 15Psi

$$R_S F = \frac{783}{831} \times 0$$

$$= 0$$

From $P > P_b$ the solution gas/oil ratio at flash condition is constant.
$B_o F$ = Oil formation volume factor at flash condition

$$B_o F = \frac{B_o Fb}{B_o db} \times B_{Od}$$

$B_o Fb$ = 1.456 Res BBL/STB

$B_o db$ = 1.460 Res BBL/STB

$B_o d$ = 1.460

For $P \leq P_b$

P = 2000Psi

$$B_oF = \frac{1.456}{1.460} \times 1.460$$

$$= 1.456 \text{ Res BBL/STB}$$

$$P = 1600 Psi$$

$$B_oF = \frac{1.456}{1.460} \times 1.399$$

$$= 1.395 \text{ Res BBL/STB}$$

$$P = 1200 Psi$$

$$B_oF = \frac{1.456}{1.460} \times 1.340$$

$$= 1.336 \text{ Res BBL/STB}$$

$$P = 800 Psi$$

$$B_oF = \frac{1.456}{1.460} \times 1.278$$

$$= 1.224 \text{ Res BBL/STB}$$

$$P = 15 Psi$$

$$B_oF = \frac{1.456}{1.460} \times 1.062$$

$$= 1.059 \text{ Res BBL/STB}$$

For P > Pb

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

$$B_oF = \frac{1.456}{1.460} \times 1.482$$

$$= 1.478 \text{ Res BBL/STB}$$

$$P = 4000 \text{ Psi}$$

$$B_oF = \frac{1.456}{1.460} \times 1.491$$

$$P = 3500 \text{ Psi}$$

$$B_oF = \frac{1.456}{1.460} \times 1.499$$

$$= 1.495 \text{ Res BBL/STB}$$

$$P = 3000 \text{ Psi}$$

$$B_oF = \frac{1.456}{1.460} \times 1.509$$

$$= 1.505 \text{ Res BBL/STB}$$

P = 2575 Psi

$$B_oF = \frac{1.456}{1.460} \times 1.517$$

= 1.513 Res BBL/STB

P = 2420 Psi

$$B_oF = \frac{1.456}{1.460} \times 1.522$$

= 1.518 Res BBL/STB

Table 5: Corrected solution gas/oil ratio and formation volume factors at flash condition

Pressure (psig)	Formation volume factor (B_{od})	Solution gas/oil ratio at diff. (Rsd)	Gas deviation factor (Z)	Solution Gas/Oil ratio (scf/stb) (R_{sd})	Liberated Gas/Oil ratio (scf/stb)	Specific Gravity of liberated gas (γ_g) Air = 1.00
4500	1.482	831.0	0	0	0	1.478
4000	1.491	831.0	0	0	0	1.487
3500	1.499	831.0	0	0	0	1.495
3000	1.509	831.0	0	0	0	1.505
2575	1.517	831.0	0	0	0	1.513
2435	1.522	831.0	0	0	0	1.518
2000	1.460	687.0	144.0	0.695	647.3	1.456
1600	1.399	561.0	270.0	0.692	528.6	1.395
1200	1.340	442.0	419.0	0.699	416.5	1.336
800	1.278	331.0	500.0	0.723	311.9	1.274
400	1.211	214.0	617.0	0.794	201.6	1.208
15	1.062	0	831.0	1.936	0	1.059

b) *Validation of PVT Parameters using Standing Correlations*

(i)   Estimation of Bubble Point Pressure (P_b)

From standing correlations for the reservoir condition

$$R_{Sb} = 647.3 \text{ SCF/STB, } T_R - 186^oF, \gamma_g = 1.306, \gamma_o API = 30^o API$$

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

$$y_g = 0.00091\, T_R - 0.0125\, \gamma_o API$$

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

$$y_g = -0.20574$$

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

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

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

The bubble pressure = 1934.271psi

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

$$P < P_b$$

$$P = 2000psi$$

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

$\gamma_g = 1.306$, P = 2000PSI, TR = 186°F, γ_oAPI = 30

$\gamma_g = 0.00091\text{TR} - \gamma_o.\text{API}$

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

$\gamma_g = -0.20574$

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

= 6710.03 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

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

$$= 1781.5 \text{ SCF/STB}$$

$$P = 4000 \text{ PSI}$$

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

$$= 1,545.9 \text{ SCF/STB}$$

$$P = 3500 \text{ PSI}$$

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

$$= 1,316.3 \text{ SCF/STB}$$

$$P = 3000 \text{ PSI}$$

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

$$= 1,093.4 \text{ SCF/STB}$$

$$P = 2575 \text{ PSI}$$

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

$$= 909.7 \text{ SCF/STB}$$

$$P = 2420 \text{ PSI}$$

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

$$= 844.2 \text{ SCF/STB}$$

(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, $\gamma_g = 0.698$, $\gamma_o.API = 30$

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 ≤ P$_b$

InC$_O$ = -0.664 − 1.430 InP − 0.395 In Pb + 0.390 InT + 0.455 In (R$_{Sob}$)

+ 0.262 In (γ_o.API)

P = 2000 psi, TR = 186°F, 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)

$$+ 0.262 \ln (30)$$

$$\ln C_O = -8.25412$$

$$\ln C_O \; e^{-8.25412}$$

$$\ln C_O = 26.02 \times 10^{-5} \; psi^{-1}$$

$$P = 1200 \; psi$$

$$\ln C_O = -0.664 - 1.430 \ln 1200 - 0.395 \ln 1200 + 0.390 \ln 186 + 0.455 (647.3)$$

$$+ 0.262 \ln (30)$$

$$\ln C_O = -7.7291$$

$$\ln C_O = e^{7.7291}$$

$$\ln C_O = 43\text{-}98 \times 10^{-5} \; Psi^{-1}$$

$$P = 800 \; psi$$

$$\ln C_O = -0.664 - 1.430 \ln 800 - 0.395 \ln 800 + 0.390 \ln 186 + 0.455 (647.3)$$

$$+ 0.262 \ln (30)$$

$$\ln C_O = -60.9813$$

$$\ln C_O = e^{-6.9813}$$

$$\ln C_O = 92.18 \times 10^{-5} \; Psi^{-1}$$

$$P = 400 \; psi$$

$$\ln C_O = -0.664 - 1.430 \ln 400 - 0.395 \ln 400 + 0.390 \ln 186 + 0.455 (647.3)$$

$$+ 0.262 \ln (30)$$

$$\ln C_O = -5.72414$$

$$\ln C_O = e^{-5.72414}$$

$$\ln C_O = 32.66 \times 10^{-4} \; Psi^{-1}$$

$$P = 15 \; psi$$

$$\ln C_O = -0.664 - 1.430 \ln 15 - 0.395 \ln 15 + 0.390 \ln 186 + 0.455 (647.3)$$

$$+ 0.262 \ln (30)$$

$$\ln C_O = -0.26809$$

$$\ln C_O = e^{-0.26809}$$

$$\ln C_O = 13.08 \times 10^{-4} \; Psi^{-1}$$

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

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

Where

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

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

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

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

$$F = 247.5605$$

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

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

$$P > P_b$$

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

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

$$B_{ob} = .0675 \, e^{[10.12 \times 10^{-6} \, (2000 - 4500)}$$

$$B_{ob} \quad 1.0675 \, e^{-0.0253}$$

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

$$P = 4000 \text{ psi}$$

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

$$B_{ob} = 1.0675 \, e^{[11.39 \times 10^{-6} \, (2000 - 4000)}$$

$$B_{ob} \quad 1.0675 \, e^{-0.02278}$$

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

$$B_{ob} = 1.0675 \, e^{[15.19 \times 10^{-6} \, (2000 - 3000)}$$

$$B_{ob} = 1.0675 \, e^{-0.0159}$$

$$B_{ob} = 1.0514 \text{ BBL/STB}$$

$$P = 2575 \text{ psi}$$

$$B_{ob} = 1.0675 \, e^{[17.7 \times 10^{-6} \, (2000 - 2575)}$$

$$B_{ob} = 1.0675 \, e^{-0.0101775}$$

$$B_{ob} = 1.057 \text{ BBL/STB}$$

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

$$B_{ob} = 1.0675 \, e^{[17.31 \times 10^{-6} \, (2000 - 2575)}$$

$$B_{ob} = 1.0675 \, e^{0}$$

$$B_{ob} = 1.0675 \text{ BBL/STB}$$

$$P < Pb$$

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

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

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

$$R_{so} = \gamma$$

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

$$F = 244.433$$

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

$$B_o = 1.0661 \text{ BBL/STB}$$

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

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

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

$$F = 240.9406$$

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

$$B_o = 1.0645 \text{ BBL/STB}$$

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

$$R_{so} = 222.65 \text{ SCF/STB}$$

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

$$F = 237.6803$$

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

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

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

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

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

$$F = 234.748$$

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

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

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

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

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

$$F = 232.543$$

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

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

(v) 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

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

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

$$M = 0.3765$$

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

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

$$=-0.16819$$

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

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

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

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

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

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

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

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

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

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

$$A=0.22061$$

$$B=0.42166$$

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

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

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

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

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

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

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

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

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

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

$$A = 0.2554$$

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

$$B = 0.4628$$

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

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

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

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

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

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

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 $P < P_b$

$$P = 1600\ psi$$

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

$$M = 2.6(1600)^{1.187}e^{[-11.513-8.98(10^{-5})\times1600]}$$

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

$$M = 0.143163$$

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

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

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

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

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

$$M = 2.6(1200)^{1.187}\,e^{[-11.513-8.98(10^{-5})\times1200]}$$

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

$$M = 0.10547$$

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

$$B = 0.968477$$

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

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

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

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

$$\mu_{ob} = 3.36809\left(\frac{15}{2000}\right)^{6.5467\times10^{-4}}$$

$$\mu_{ob} = 4.1309\times10^{-4}\ CP$$

$$\mu_{o} = 4.1309\times10^{-4}\ CP$$

Where μ_{ob} = dead oil vis cos ity, CP

μ_{ob} = oil vis cos ity at bubble po int pressure in CP

μ_{o} = oil vis cos ity in CP

3.3 Tables of Value for Complete PVT Report

Table 6: Validation of PVT parameters using standing correlations

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}

c) 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.

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

$$100^o\text{F} < TR < 258^o\text{F}$$

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

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

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

$$0.59 < \gamma_g < 0.95$$

The solution $\dfrac{gas}{oil}$ 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.

(v) 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.

V. Discussion of Result

Crude oil usually contains some dissolved gas when in the reservoir under pressure. As the oil well are drilled and completed and oil begin 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). 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 most 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 (Elkatatny and Mahmoud, 2018). The difference is due to the representation of PVT sample. The expansion of the reservoir fluids is a function of the fluid pressure in any particular 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%. (Tariqet al., 2021)

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. 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) suppose to be unity at standard conditions of 0 psig and 60°F, above P_b the understaturated 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 (Egbogah, 1981).

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 the oil compressibility is strongly a function of the reservoir pressure (Curtis and Michael, 2000).

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

(Arabloo et al., 2014). 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. An adjustment in the gravity of the residual oil is not required (Drohm et al., 1998).

VI. Conclusions

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.

In this research work, we analyzed the black oil samples from the X Field at the Reservoir Fluids Laboratory (RFL) in Port Harcourt, Nigeria using PVT analysis. Basic PVT Parameters for the samples were derived and we validated the report by employing Standing correlations.

The test conducted during the PVT studies is Constant Composition Expansion (CCE) tests and Separator Flash (SF) test with surface and subsurface recombination sample. 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. (Tohidi-Hosseini, et al 2016).

VII. Recommendations

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. In order to check the quality of the sample, duplicate samples should always be taken if the reservoir contains a 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. (Drohm, et al 1988).

4. 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.

5. 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.

References Références Referencias

1. Arabloo, M.; Amooie, M.-A.; Hemmati-Sarapardeh, A.; Ghazanfari, M.-H.; Mohammadi, A. H. Application of constrained multi-variable search methods for prediction of PVT properties of crude oil systems. Fluid Phase Equilib. 2014, 363, 121−130.
2. Cosse, R. (1993). Basics of Reservoir Engineering, Technip, Paris by Imprimerie Nouvelle.
3. Curtis, H.W., Michael, R.B. (2000). Phase Behaviour, Petroleum Publishing Co. Pulsa pp. 80-120.
4. Drohm, J.K., Goldthorpe, W.H., and Trengove, R. (1988). On the quality of data from standard gas-condensate PVT experiments, SPE Gas Technology Symposium, NS 17768, Dallas, pp. 13-68.
5. Egbogah, E.O. (1981). "An improved temperature viscosity correlation for crude systems paper 83-84-32 presented at the SPE annual technical conference and Exhibition, 5-7 October, San Antonio, Texas.
6. Elkatatny, S.; Mahmoud, M. (2018). "Development of new correlations for the oil formation volume factor in oil reservoirs using artificial intelligent white box technique." Petroleum 2018, 4, 178−186.
7. Fattah, K. A. & Lashin, A. (2018). "Improved oil formation volume factor (Bo) correlation for volatile oil reservoirs: An integrated non-linear regression and genetic programming approach." J. Eng. Sci. King Saud Univ. 2018, 30, 398−404.
8. Foster, N.F. and Beaumont, E.A. (1987). "Reservoir Evaluation, Treatise of Petroleum Geology" Geologic Basin I (Reprint Series No. 1).
9. Hashemi Fath, A.; Madanifar, F.; Abbasi, M. (2020). "Implementation of multilayer perceptron (MLP) and radial basis function (RBF) neural networks to predict solution gas-oil ratio of crude oil systems." Petroleum 2020, 6, 80−91.
10. Hemmati-Sarapardeh et al (2016). "A soft computing approach for the determination of crude oil viscosity: light and intermediate crude oil systems." J. Taiwan Inst. Chem. Eng. 2016, 59, 1−10.
11. Jones, S.C. and Roselle, W.O. (1978). Graphical techniques for determining relative permeability from displacement experiments; JPT 807. Trans AIME, 265.
12. Kanu, A. U., & Ikiensikimama, S. S. (2014.) "Globalization of Black Oil PVT Correlations."

Presented in SPE Nigeria Annual International Conference and Exhibition, Lagos, Nigeria, 5-7 August.

13. Mahdiani, M. R.; Kooti, G. The most accurate heuristic-based algorithms for estimating the oil formation volume factor. Petroleum 2016, 2, 40−48.

14. Moses, P.L. (1986). Engineering Applications of Phase Behaviour of Crude-oil and Condensate Systems, Journal of Petroleum Technology, 38(7), pp. 28-223.

15. Standing, M.B. (1947). "A pressure, volume, temperature, correlation for mixtures of California oils and Gases Drilling and Production Practice" pg. 275.

16. Tariq, Z.; Mahmoud & M.; Abdulraheem, (2021). "A. Machine Learning Based Improved Pressure−Volume−Temperature Correlations for Black Oil Reservoirs." J. Energy Resour. Technol. 2021, 143, 113003.

17. Tohidi-Hosseini, et al (2016). "Toward prediction of petroleum reservoir fluids properties: A rigorous model for estimation of solution gas-oil ratio." J. Nat. Gas Sci. Eng. 2016, 29, 506−516.

18. Udegbunam, E.O. and Owolabi, O.O. (1983). Correlation for fluid physical properties of Nigerian crude, proceeding of the International SPE Conference, Port Harcourt, NS 215, Nigeria, pp. 200-205.

19. Vasquez, M. and Beggs, H.D. (1987). Correlations for fluid physical property prediction. SPE Annual Technical Conference and Exhibition, NS 6719, Denver, Coloration, pp. 9-106.

20. Whitson, C.H. 5-7 October (1981). "Evaluating constant volume depletion Data", paper SPE 10067 presented at the SPE Annual Technical Conference and Exhibition, Son Antonio, Texas.

21. Zamani, H. A. et al (2015). "Implementing ANFIS for prediction of reservoir oil solution gas-oil ratio." J. Nat. Gas Sci. Eng. 2015, 25, 325−334.