



## PVT Fluid Sampling, Characterization and Gas Condensate Reservoir Modeling

Julius U. Akpabio<sup>1,2\*</sup>, Sunday O. Isehunwa<sup>2</sup> and Oluwatoyin O. Akinsete<sup>2</sup>

<sup>1</sup>Department of Chemical and Petroleum Engineering, University of Uyo, Uyo, Nigeria.

<sup>2</sup>Department of Petroleum Engineering, University of Ibadan, Ibadan, Nigeria.

### Authors' contributions

*This work was carried out in collaboration between all authors. Author JUA designed the study, wrote the protocol, and wrote the first draft of the manuscript. Author OOA confirmed the cited literatures, and author SOI reviewed the simulation process, analysis and results. All authors read and approved the final manuscript.*

### Article Information

DOI: 10.9734/AIR/2015/16000

#### Editor(s):

(1) Pradip K. Bhowmik, Department of Chemistry, University of Nevada Las Vegas, Las Vegas, USA.

#### Reviewers:

(1) Anonymous, Suez Canal University, Egypt.

(2) Anonymous, Inha University, South Korea.

(3) Anonymous, Ladoke Akintola University of Technology (LAUTECH), Nigeria.

Complete Peer review History: <http://sciencedomain.org/review-history/10630>

Original Research Article

Received 31<sup>st</sup> December 2014

Accepted 9<sup>th</sup> June 2015

Published 23<sup>rd</sup> August 2015

### ABSTRACT

When reservoir pressure decreases in gas condensate reservoirs, there is a compositional change which makes the system difficult to handle. This type of system requires an Equation of State (EOS) to ensure proper fluid characterization so that the Pressure Volume Temperature (PVT) behavior of the reservoir fluid can be well understood. High quality and accurate PVT data will help reservoir engineers to predict the behavior of reservoir fluids and facilitate simulation studies. The aim of this study is to determine what to do on reservoir fluid before carrying out reservoir modeling. PVT data were obtained from a reservoir fluid in the Niger Delta which was sampled following standard procedures. Then the laboratory experiments were critically examined to ensure accuracy, consistency and validity before PVT analysis. Finally, the results from the PVT experiments were imported into PVT software and subsequently in a reservoir simulator for simulation studies. These processes generate the EOS model for reservoir modeling of gas condensate reservoirs. The mass balance test, Hoffman plot and CCE/CVD (Constant Composition Expansion and Constant Volume Depletion) comparison plots were used to validate PVT data. From these tests,

\*Corresponding author: E-mail: [juliakpabio@yahoo.com](mailto:juliakpabio@yahoo.com);

the consistencies of the data were ascertained and the composition added up to 100%. The pattern of the CCE/CVD comparison plot was observed to reflect that less liquid dropout was experienced later in the depletion process of the CVD experiment than in the CCE experiment. PVT validation checks help to confirm the Gas oil ratio of the system and the richness of the gas condensate fluid. It is imperative to obtain representative reservoir fluid samples and carry out reliable laboratory experiments to generate PVT data for fluid characterization. PVT fluid characterization and consistency checks will ensure that accurate results are obtained from reservoir simulation models leading to proper reservoir management.

**Keywords:** Fluid characterization; equation of state; retrograde condensate; reservoir modeling; fluid sampling.

## NOMENCLATURES

$A_1$	=	Slope of the Hoffman et al Plot
$A_o$	=	Intercept of the Hoffman et al plot
BIP	=	Binary Interaction Parameter
CCE	=	Constant Composition Expansion
CVD	=	Constant Volume Depletion
$C_f$	=	Characteristic factor correlation
EOS	=	Equation of State
$F$	=	Total moles of Feed
$F_i$	=	Hoffman Factor
FVF	=	Formation Volume Factor
FV	=	Intercept of Mass Balance Plot
GOR	=	Gas Oil Ratio
K-Value	=	Y/X
$L$	=	Total moles of separator Liquid
L/V	=	Slope of Mass Balance Plot
$M_i$	=	Molecular weight of Heptane plus
$P_c$	=	Critical Pressure
$P_D$	=	Dew Point Pressure
PR	=	Peng-Robinson
PT	=	Patel and Teja
$P_{sc}$	=	Pressure at standard conditions
PVT	=	Pressure Volume Temperature
RK	=	Redlich Kwong
SRK	=	Soave Redlich Kwong
$T$	=	Separator Temperature
$T_b$	=	Normal Boiling Temperature
TBP	=	True Boiling Point
$T_c$	=	Critical Temperature
$V$	=	Total moles of separator Vapour
VLE	=	Volume Liquid Equilibrium
$X_i$	=	Moles fraction of component $i$ in Liquid
$Y_i$	=	Mole fraction of component $i$ in Vapour
$Z_i$	=	Mole fraction of component $i$ in feed
ZJ	=	Zudkevitch and Joffe
$\gamma_i$	=	Specific Gravity

## 1. INTRODUCTION

There are five main groups of reservoir fluids namely: Black oil, volatile oil, retrograde condensate, wet gas and dry gas. The retrograde condensate fluid is very complex due to the fluid behavior and properties. This reservoir is usually located between the critical temperature and the cricondetherm on the reservoir fluid's pressure-temperature diagram [1]. Fluid flow in gas condensate reservoir is very complex and involves phase changes, multi-phase-flow of the fluid (oil and gas) and possibly water, phase redistribution in and around the wellbore and retrograde condensation [2]. In order to adequately handle this fluid an Equation of State (EOS) model is required. This is an analytical expression that relates pressure to the temperature and volume of a fluid which is used to characterize reservoir fluids. Pressure Volume Temperature (PVT) relationship for real hydrocarbon fluids needs to be properly described to ascertain the volumetric and phase behavior of Petroleum reservoir fluids.

Reservoir and production engineers usually require PVT measurements for effective operations and one major issue is the use of EOS for the description of phase behavior of fluids for development of compositional simulators [3,4]. Different types of EOS include Van der Waals, Peng-Robinson (PR), Redlich-Kwong (RK), Zudkevitch and Joffe (ZJ), Patel and Teja (PT), Soave Redlich Kwong (SRK) etc. these EOS have been published in the past to model phase behavior of gas condensate fluids [5,6]. It is important to know the gas condensate phase behavior in order to predict the performance of the reservoir and future processing needs. The experimentally measured data is usually matched (by linear regression) with the simulated data to increase the degree of confidence of the EOS model.

EOS can be modeled with the following general procedure:

- a) EOS model is built with an EOS correlation using available composition at reference pressure, temperature and depth.
- b) To ensure that the GOR and density match, the molecular weight or specific gravity of the pseudo component is changed by 5-10% to get close to the densities.
- c) Binary Interaction Parameters (BIP) are used to match saturation pressure while the Pseudo components are split.
- d) Laboratory data is entered and deviation between the calculated and experimental values is checked.
- e) The BIPs and critical properties of pseudo components are regressed if a large deviation is noticed.
- f) EOS model is lumped for use in simulation model, after linear regression to reduce the simulation time.

EOS correlation is used with accurate PVT characterization to develop gas condensate reservoir models. When developing gas condensate reservoirs, a major challenge is the phenomenon called “condensate banking.” This phenomenon occurs when condensate drops out near wellbore region as pressure drops below the dew point pressure, causing condensate to drop and form a ring-like structure which ultimately reduces the well deliverability [7].

There is need for accurate sampling of the reservoir fluids to achieve a good EOS model. Laboratory experiments must be performed correctly to develop accurate EOS models when the sample is a good representative of the reservoir fluids [6]. PVT models are used to generate mathematical algorithms expressed as Equation of State [8]. Some practical limitations in obtaining gas condensate PVT data include accurate laboratory PVT data and compositional changes due to pressure drop below the dew point and uncertainties associated with small liquid volumes [9]. The profitability in the development of any gas condensate reservoir depends on four factors: field location and size, local markets for separated gas and condensate, phase behavior of reservoir fluid and tax regime.

A fundamental tool for planning the development of a field and evaluation of field production performances is reservoir simulation studies. Part of the requirement for any integrated reservoir studies is the reservoir fluid PVT model [8].

### 1.1 Fluid Characterization and Gas Condensate Fluids

One way of obtaining representative reservoir fluid, is by sampling the fluid just after the completion of the drilling, since pressure is less likely to drop below the dew point thereby creating a two phase in the reservoir [10-13]. A mono-phasic condition should be maintained during sampling and transfer to laboratory for analysis. In order to realize this objective, the sample drawdown pressure should be controlled and kept as close as possible to the reservoir pressure and above the dew point [14,15].

From the well stream composition of a reservoir fluid (which is obtained from the recombination process), it is possible to know the type of reservoir fluid. The major characteristic feature of a gas condensate fluid is the Gas GOR (Gas-Oil Ratio). The condensate fluid can be further classified into four categories: Lean, medium, rich and very rich condensate [16] as shown in Table 1. As the isothermal condition of the reservoir fluid approaches the critical point, in the phase envelope, the richness of the fluid is increased. Fig. 1 shows the lean and rich gas condensate phase envelopes [17].

Rich and lean gas condensate phase envelopes can be differentiated by Fig 1a and 1b and known by the size of heptane plus as well as the percentage of liquid dropout. When pressure declines at reservoir temperature, a rich gas condensate forms more liquid dropout than a lean gas. The constant compositional changes in the gas condensate reservoir, makes it a complex system, requiring compositional simulation to be able to model the phase behavior of the fluid and evaluate the recovery processes properly.

**Table 1. Classification of Gas Condensate Fluids [16]**

	<b>Lean</b>	<b>Medium</b>	<b>Rich</b>	<b>Very rich</b>
CGR(STB/MMSCF)	<50	50 - 125	125 - 250	>250

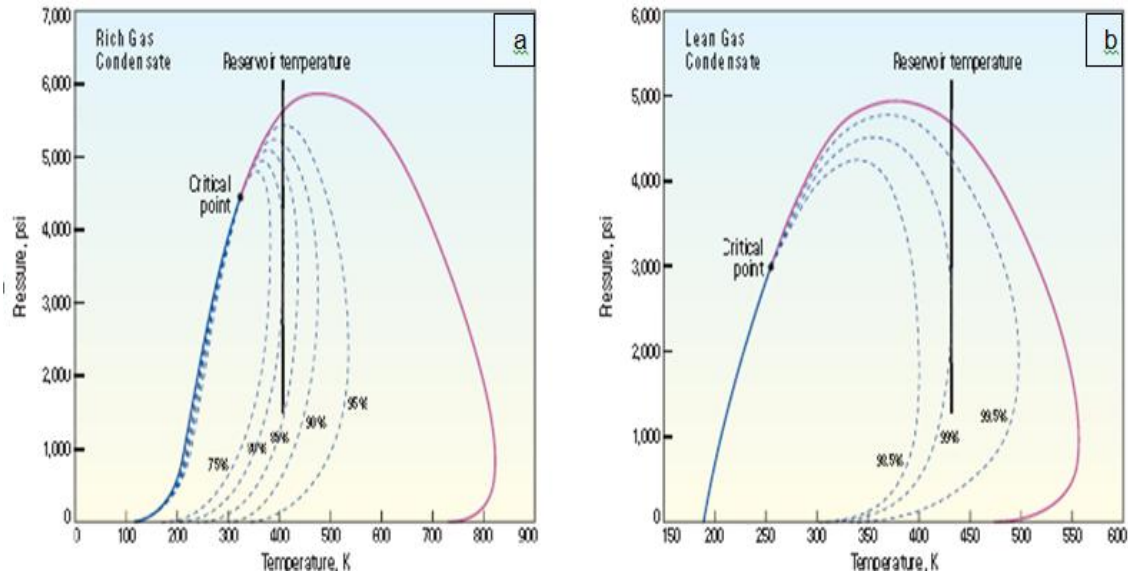


Fig. 1a. and 1b. Phase envelopes of rich and lean gas condensate fluids [17]

## 2. METHODOLOGY

Fluid samples for this study were obtained from the Niger Delta region of Nigeria. The record of the sampling process and information about the temperature and pressures were used to ascertain the suitability of the condition for obtaining representative reservoir fluid samples. Table 2 shows the compositions of the gas condensate fluid and other properties of the fluid. Standard sampling procedures will be highlighted and laboratory analysis performed on the fluid before characterization and EOS generation.

### 2.1 Sampling Procedures for Gas Condensate Fluid

#### 2.1.1 Subsurface samzpling

The following steps are the specific procedure for subsurface sampling:

- i. Condition the well to insure that a single-phase, representative fluid is flowing at the productive interval
- ii. Either shut in the well or allow it to continue flowing at a very low rate
- iii. Run pressure and temperature surveys to determine fluid levels and pressures
- iv. Select the sampling point and run the bottom hole fluid sampler to depth
- v. Actuate the sampler and retrieve the sample.

- vi. Repeat the sampling operation to obtain duplicate samples (preferably three samples should be retrieved).
- vii. Perform a quality check on the samples at the surface
- viii. Transfer the samples to a storage container for transport to the laboratory

A minimum of triplicate samples should be collected. This is to permit comparison of sample compositions and properties and to have backup samples in case of leakage during transit from field to laboratory. For gas-condensate samples, the optimum procedure is to ship the entire subsurface sampling tool section to the laboratory, to minimize the possibility of leakage [13,18].

#### 2.1.2 Surface sampling

The following steps are the specific procedures for surface sampling [19]:

- i. Condition the well to insure that a single-phase representative fluid is flowing into the wellbore
- ii. Maintain the final conditioning flow rate
- iii. Accurately measure and record the GOR
- iv. Sample the gas and oil streams at the primary or first stage separator and at separator pressure.
- v. Accurately record sample data and tag for shipment to laboratory.

## 2.2 Analysis and Tuning of PVT Data

The results from the laboratory experiments which are the CCE, CVD, viscosity and separator tests were inputted into the PVTsim software. The Fluid is characterized by delumping and lumping of the plus fractions and assigning of individual properties (e.g.  $T_c$ ,  $P_c$ , eccentric factor,  $M_w$  etc.) to these components using an equation of state (EOS). The EOS parameters were tuned to match experiments' PVT data of the CCE and CVD tests with the simulation results. The lumping and delumping of the C7 plus fraction was necessary to reduce the number of components used in the EOS calculations also reduce compositional model computing time [20].

## 2.3 Basic Experiments before Fluid Characterization

Constant Composition Expansion (CCE) and Constant Volume Depletion Experiments (CVD) are the two basic experiments carried out on gas condensate fluids before characterization. CCE experiment is performed in a high-pressure gas

condensate windowed cell. A part of the recombined sample was changed to the cell and expanded thermally to the reservoir temperature of 176.6°F. This experiment is started at a pressure much higher than the reservoir pressure and reduced stepwise until the dew point pressure is observed and recorded. Other parameters recorded in this test are the deviation factor, the compressibility factor, the liquid dropout, gas density and relative gas volumes as seen in Table 3.

CVD experiment is carried out on the fluid at reservoir temperature of 176.6°F and dew point pressure which was determined by the CCE experiment. The experiment involves a series of pressure expansions and constant pressure displacements to maintain the sample in a constant volume that was equal to the volume of sample at dew point pressure. The process is repeated until an abandonment pressure, which was 524 Psia. The well stream was pumped from the PVT cell into a pre-weighed flask submerged in liquid nitrogen and condensed. The condensed

**Table 2. Wellstream compositions of fluid A**

Component	Gas mol % ( $y_i$ )	Liquid mol % ( $x_i$ )	Reservoir fluid mol % ( $z_i$ )
N2	0.15	0	0.14
CO2	0.18	0	0.18
H2S	0	0	0
C1	87.98	0	87.26
C2	5.29	0.1	5.25
C3	2.83	0.07	2.81
i-C4	0.68	0.06	0.67
n-C4	0.91	0.13	0.9
i-C5	0.41	0.21	0.41
n-C5	0.31	0.25	0.31
C6	0.56	1.73	0.57
C7+	0.7	97.45	1.5
TOTAL	100	100	100
Liquid density (IB/FT3)	50.067		
Liquid MW		156.37	
Gas gravity (air = 1)	0.802		
GOR (scf/sepbbbl)			82918.7

**Table 3. Constant volume depletion test-produced well stream properties at 176.6°F**

Steps	Press. (Psia)	Gas Den. (g/cc)	Gas gravity	Gas Z factor	Gas FVF	Gas Visc.(cp)	2-Z factor	Retrog rade liq. (%)	Cum. Prod.fluid liq.
Dew Point.	4191	0.238	0.721	0.862	0.00369	0.0276	0.862	0	0
1	3799	0.187	0.702	0.831	0.00392	0.0251	0.824	0.27	4.92
2	3099	0.153	0.678	0.794	0.0046	0.0214	0.786	1.1	13.36
3	2388	0.118	0.664	0.79	0.00594	0.0183	0.768	1.93	28.65
4	1610	0.078	0.657	0.83	0.00925	0.0158	0.746	2.65	46.98
5	978	0.046	0.656	0.905	0.0166	0.0142	0.729	2.61	64.04
6	524	0.025	0.662	0.962	0.0325	0.0134	0.708	2.25	74.05

gas phase is then gradually allowed to return to ambient temperature. The gas evolves and the residual condensate are collected separately, weighed and analyzed. The quantities that are recorded during this experiment are liquid dropout, cumulative produced fluid; gas density and gas z-factor, see Table 4. Phase and volumetric behavior of mixtures using any of the EOS models can be predicted by obtaining such properties as the critical properties ( $T_c$ ,  $P_c$ ) and accentric factor,  $\omega$  for each component in the mixture.

## 2.4 Compositional Consistency

The consistency of the fluid composition can be determined by evaluating the PVT data. One major consistency test is the summation of the composition to ensure they add up to 100%. In modern PVT reports, inconsistencies in composition are usually very small and are seen in unnoticeable figures instead of errors [21]. Apart from the summation of the composition, other techniques for consistency checks are, the mass balance plot, Hoffman plot and Buckley plot. While the mass balance plot is a quantitative method, the Hoffman and Buckley plots are qualitative methods of assessing PVT data.

### 2.4.1 Mass balance test

This test is used to assess the feed composition and the separator vapour and liquid composition for consistency. The basis for the test is the mass balance criteria of the component. One mole of fluid of composition  $z$  is considered at a certain temperature and pressure ( $T$ ,  $P$ ); it can be split into liquid and vapour of  $L$  moles and  $V$  moles of compositions respectively [22]. An  $L$  mole of liquid has the compositions  $x_1, x_2, \dots, x_n$ , and a  $V$  mole of vapour has compositions of  $y_1, y_2, \dots, y_n$ . Then

$$L + V = 1 \quad (1)$$

and

$$Lx_i + Vy_i = Z_i \quad (2)$$

$$\sum_{i=1}^n x_i = \sum_{i=1}^n y_i = \sum_{i=1}^n z_i = 1 \quad (3)$$

Therefore the  $K$ -value of the  $i^{\text{th}}$  component is expressed as:

$$K = y_i/x_i \quad (4)$$

Hence, the expression for the  $x_i$  and  $y_i$  are as follows:

$$Lx_i + Vy_i = Fz_i \quad (5)$$

Dividing through by  $Z$

$$L(x_i/z_i) + V(y_i/z_i) = F \quad (6)$$

Dividing through by  $V$  will give

$$L/V(x_i/z_i) + (y_i/z_i) = F/V \quad (7)$$

This translates to

$$y_i/z_i = (-L/V)x_i/z_i + F/V \quad (8)$$

This is a straight line equation obtained by plotting  $y_i/z_i$  against  $x_i/z_i$  to generate an intercept,  $F/V$  and a negative slope ( $L/V$ ); this negative slope is equivalent to the measured GOR. Table 2 is used to generate this mass balance plot. Deviation from the straight line can be seen as mass balance inconsistency. The  $R^2$  value must tend towards unity (Fig. 2). This plot is sometimes used to identify discrepancies in the reported compositions. The reciprocal of the slope may be used to compute GOR and thereafter compare with the measured GOR. The conversion from mole to barrels is necessary when the values of the liquid density and molecular weight are provided. The feed compositions used in this study yielded a good result in terms of consistency. The separator liquid and vapour can be mathematically recombined to obtain the well stream composition. From the graph, the value of the slope was 0.0083 which gives a GOR of 82201.8 scf/sep. bbl. upon conversion of the reciprocal of the slope. The difference between the calculated and measured GOR is 0.86%. The measured GOR is 82918.7 scf/sep. bbl. This result shows that the value of the liquid molecular weight and density are close to the reported GOR. If this difference is large, then the values of the reported liquid molecular weights and densities are inaccurate. This will make the tuning by linear regression of the equation of state difficult.

The mass balance of the gas composition can be expressed by Equation (9).

$$y = -0.0083x + 1.0088 \quad (9)$$

And  $R^2$  is 0.9997

Using some conversion factors, the slope of the mass balance plot can be expressed as GOR.

$$GOR = \frac{1 \text{ lbmol}}{0.0083 \text{ lbmol}} * \frac{379.5 \text{ scf}}{\text{lbmol}} * \frac{1 \text{ lbmol}}{156.37 \text{ lb}} * \frac{50.067 \text{ lb}}{\text{ft}^3} * \frac{5.6145 \text{ ft}^3}{\text{bbl}} \quad (10)$$

$$GOR = 82201.8 \text{ scf} / \text{stb}$$

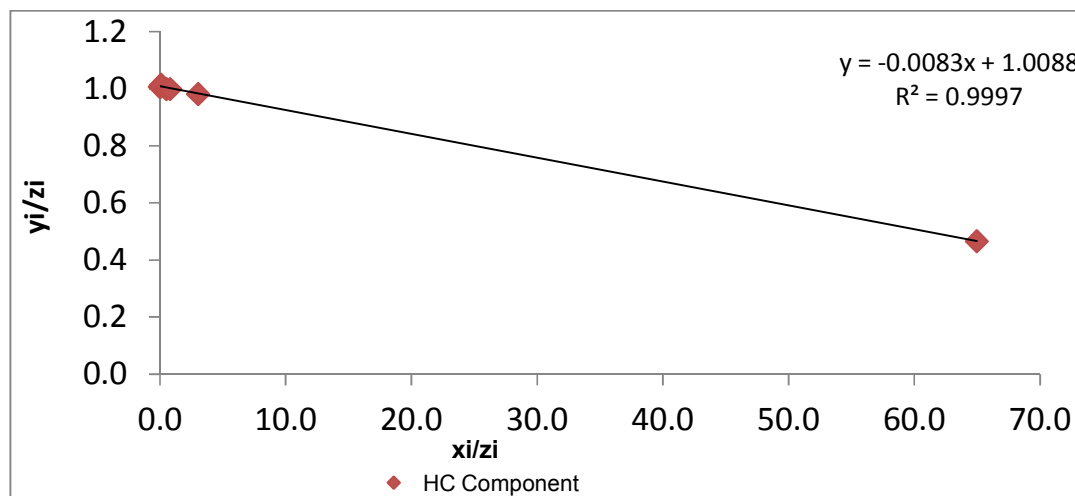


Fig. 2. Mass balance plot of recombined fluid sample

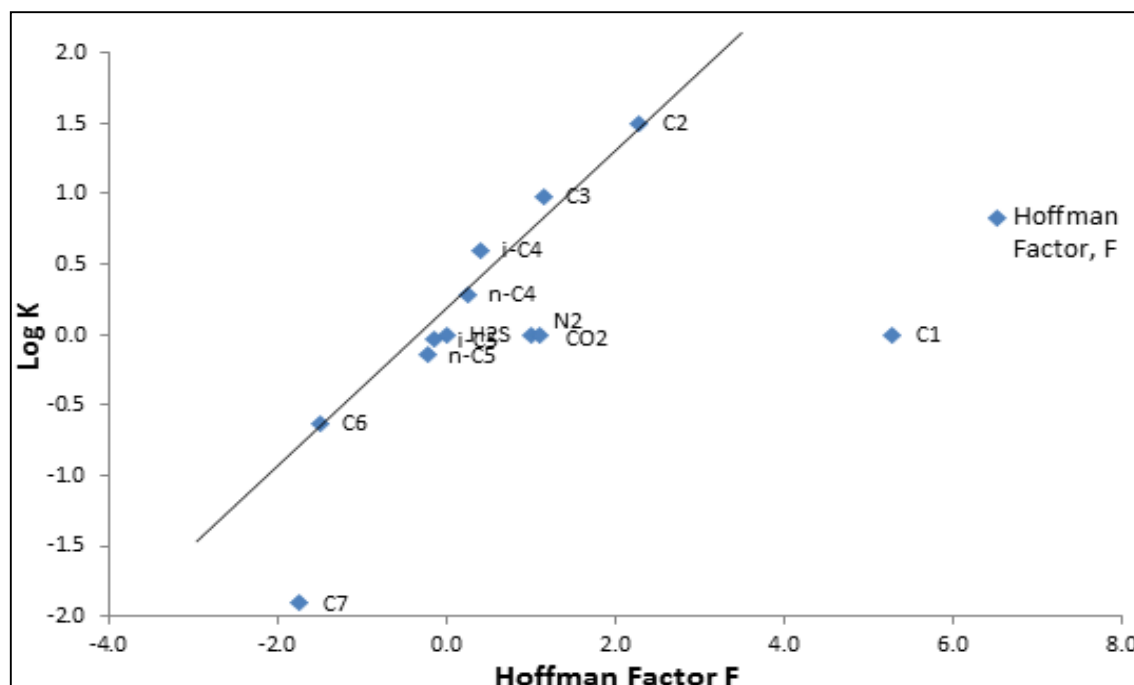


Fig. 3. Hoffman plot for the fluid A

**2.4.2 The hoffman plots**

A method for checking the recombined separator sample was proposed by Hoffman et al. [23]. This following expression was used to obtain the Hoffman plot based on the correlation of K values.

$$\log K_i = A_o + A_1 F_i \quad (11)$$

Where

$$F_i = \left( \frac{(1/T_{bi}) - 1/T}{1/T_{bi} - 1/T_{ci}} \right) \log(P_{ci}/P_{sc}) \quad (12)$$

A<sub>1</sub> and A<sub>0</sub> are slope and intercept respectively for a semi-log plot of K<sub>i</sub> versus F<sub>i</sub>. This plot shows that the trend of the graph is linear for components C<sub>2</sub> through C<sub>6</sub> for all pressures as seen in Fig. 3. However, it bends slightly downwards for heavier components at low pressures.

**2.4.3 Buckley plot**

The Buckley plot is expressed by the semi log plot of K-value versus the square of the critical temperature (Fig. 4). Usually, the heavier component deviates downwards away from the straight line.

**3. RESULTS AND DISCUSSION**

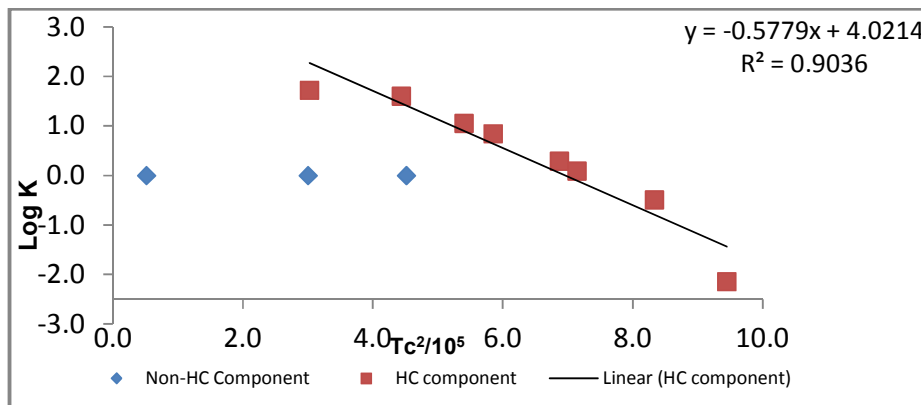
The specific gravity of Heptane plus is generated from the reservoir fluid equation for expressing the relationship between specific gravity and molecular weight before characterization of the fluid [24].

$$\gamma_i = 0.2855 + C_f (M_i - 65.9418)^{0.1299} \quad (13)$$

Where, C<sub>f</sub> is the specific gravity correlation characteristic factor. This factor is adjusted to obtain equality between calculated and experimental specific gravity of Heptane plus. The value of C<sub>f</sub> is between 0.27 and 0.31.

**Table 4. CCE experiment at 176.6°F**

Steps	Pressure	Rel. vol.	Retro. liq. %	Density	FVF	Z	Comp. (1/psia)
1	7062	0.769	0	0.309	0.00285	1.119	6.15E-05
2	6559	0.793	0	0.3	0.00294	1.072	7.19E-05
3	6056	0.822	0	0.289	0.00305	1.025	8.36E-05
4	5553	0.855	0	0.278	0.00318	0.979	9.89E-05
5	5051	0.899	0	0.265	0.00334	0.936	9.96E-05
Res. Press	4868	0.915	0	0.26	0.0034	0.918	1.16E-04
7	4548	0.949	0	0.25	0.00353	0.89	1.50E-04
P <sub>D</sub>	4191	1	0	0.238	0.00371	0.862	
9	3543	1.118	0.57				
10	3041	1.247	1.22				
11	2741	1.36	1.6				
12	2440	1.512	2.08				
13	2139	1.718	2.38				
14	1837	1.987	2.71				
15	1536	2.391	2.84				
16	1215	2.896	2.79				



**Fig. 4. Buckley plot for the reservoir fluid components**



Non-linear regression is used to determine the correlation constants to fit the experimental data from the True Boiling Point (TBP) and  $M_i$  is the molecular weight of heptane plus. This equation was originally generated based on a comparison of experimental and calculated specific gravity of 68 samples.

### 3.1 CCE and CVD Comparison Plots

Two major experiments for gas condensate fluids for determination of the reservoir phase behavior are Constant Composition Expansion (CCE) and Constant Volume Depletion (CVD) [25]. These experiments help in tuning the equation of state models for modeling reservoirs. Information obtained from these experiments are imported into PVT softwares to generate the actual reservoir fluid properties. Important information is obtained by plotting the CVD and CCE together. The dew point pressure of the reservoir was 4191 psi. and the plot shows the consistency of the two experiments. The plot has an identical dew point while the liquid dropout of the CCE is less than that of the CVD. The CCE test gives a maximum liquid dropout at a lower pressure than the CVD test. At the beginning of the retrograde process, the curves are identical but the CVD will show greater liquid dropout than the CCE as more liquid condenses. This happens because when retrograde condensation starts, the composition of the gas phase becomes leaner than the liquid phase. During CVD experiments, the composition of gas will be richer than the original composition during the CCE experiment when the leaner gas is removed. More liquid dropout is experienced because the total CVD fluid composition is richer. This is the reason why the CCE and CVD curves will initially track each

other before the CVD curve lies beneath the CCE curve. (Fig. 5).

### 3.2 Linear Regression of Data

After the CCE and CVD data are obtained, there is need to use non-linear regression to adjust the predicted EOS characterization in order to obtain an acceptable match. Some parameters need to be selected based on experience because the tuning process is usually a trial and error process. Out of the several non-linear least squares regression methods being implemented and tested, the rotational discrimination method is recommended. To obtain a good match between the simulated and experimental data a set of BIPs need to be adjusted. These BIPs help to predict the capabilities of the EOS used in Volume Liquid Equilibrium (VLE) calculations of reservoir fluids. A reasonable match could be achieved with an error of  $\pm(5-10\%)$  then the EOS can be imported into a simulation model such as ECLIPSE100, 300, Dynamo/Mores which will now function as a compositional model.

### 3.3 Gas Condensate Reservoir Modeling

A compositional simulator tracks each component of the oil and gas in the reservoir from the least component to the largest (C1, C2.....Cn). By doing this it models fluid near the critical point in the phase envelope, where changes in the pressure and temperature of the compositional system can result in very different phase behavior. In this system, oil and gas phases are represented in multi-component mixtures while EOS composition and time are represented by EOS.

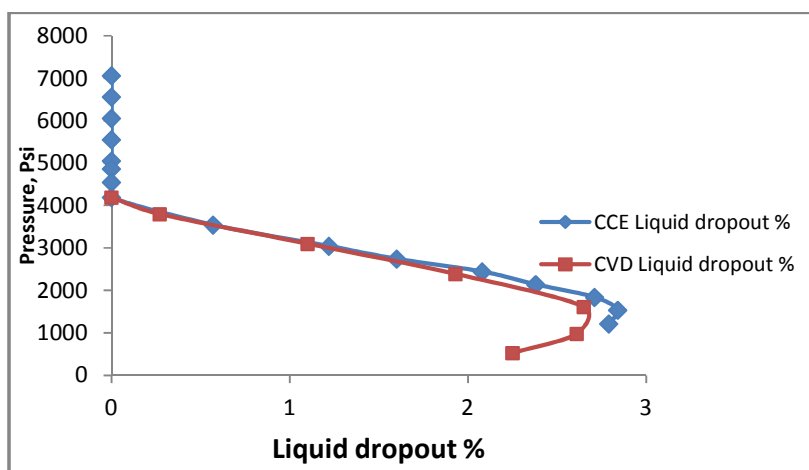


Fig. 5. Comparison plots of CVD and CCE experiments

#### 4. CONCLUSION

In order to undertake reservoir fluid modeling, fluid samples must be obtained from the reservoir, early in the life of the reservoir ensuring a monophasic condition during the sampling and transfer to laboratory.

The richness of the condensate fluid (rich or lean condensate) is determined after the PVT data from the laboratory experiments has been checked for accuracy, consistency and validity.

When the PVT data is imputed into PVT software, an EOS model is generated and tuned by linear regression to have a good match between the simulated and experimental data. The EOS model is then exported into any reservoir simulator such as Eclipse or Mores, for use as a compositional simulator.

#### COMPETING INTERESTS

Authors have declared that no competing interests exist.

#### REFERENCES

1. Thomas FB, Andersen G, Bennion DB. Gas condensate reservoir performance. *Journal of Canadian Petroleum Technology*. 2009;48(7):18-24.
2. Kool H, Azari M, Soliman MY, Proett MA, Irani CA. Testing of gas condensate reservoirs-sampling, test design and analysis paper SPE 68668-MS presented at the SPE. Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, 17-19 April; 2001.
3. Wang P, Pope GA. Proper use of equations of state for compositional reservoir simulation. Paper SPE 69071 Society of Petroleum Engineers. 2001; 53(7);74-81.
4. Nagarajan NR, Honarpour MM, Sampath, K. Reservoir fluid sampling and characterization-key to efficient reservoir management. SPE 103501 Distinguished Author Series JPT; 2007.
5. Sarkar R, Danesh AS, Todd AC. Phase behavior modeling of gas-condensate fluids using an equation of state. Paper SPE 22714 presented at the 66<sup>th</sup> Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Dallas, TX, 6-9 October; 1991.
6. Khan NM, Bilal HM, Shoaib M, Manzoor A, Shaukat W, Shakil T. Fluid characterization of a retrograde gas condensate reservoir for the simulation study. SPE 163134 presented at the SPE/PAPG Annual Technical Conference held in Islamabad, Pakistan, 3-5 December; 2012.
7. Lawrence JJ, Gupta DK. Quality assessment and consistency evaluation of PVT data, IPTC 13784 presented at the 2009 International Petroleum Technology Conference held in Doha Qatar, 7-9 December; 2009.
8. Schebetov A, Rimoldi A, Piana M. Quality check of gas-condensate PVT Studies and EOS Modeling under Input Data Uncertainty SPE 133258 presented at the SPE Gas Technical Conference and Exhibition held in Moscow, Russia, 26-28 October; 2010.
9. Eyton DGP. Practical limitations in obtaining PVT data for gas condensate systems. Paper SPE 15765 presented at the Fifth SPE Middle East Oil Show held in Manama, Bahrain, 7-10 March; 1987.
10. Lawrence JJ, Chorneyko DM, Smith CK, Nagarajan NR. Representative reservoir fluid sampling: Challenges, issues, and solutions. IPTC 12401 presented at the International Petroleum Technology Conference, Kuala Lumpur, Malaysia, 3-5 December; 2008.
11. Moses PL. Engineering application of phase behaviour of crude oil and condensate systems. *Journal of Petroleum Engineering*. 1986;38(7).
12. McCain WD, Alexander RA. Sampling gas condensate wells. *Society of petroleum engineers. Reservoir Engineering*. 1992; 358-362.
13. API Sampling Petroleum Reservoir Fluids API recommended Practice 44 Second Edition; 2003.
14. Michaels J, Moody M, Shwe T. Wireline fluid sampling paper SPE 30610 presented at the SPE Annual Technical Conference and Exhibition held in Dallas, USA, 22-25 October; 1995.
15. Bon J, Sarma H, Rodrigues T, Bon JG. Reservoir fluid sampling revisited-A practical perspective paper SPE 101037 presented at the SPE Asia and Pacific oil and Gas Conference and Exhibition, Adelaide, Australia, 11-13 September; 2006.
16. Shell Journal of Technology. August; 2012, SR 12.11683.

17. Akpabio JU, Udofia EE, Ogbu MP. PVT fluid characterization and consistency check for retrograde condensate reservoir modeling SPE 172359 prepared for presentation at the SPE Nigeria Annual International Conference and Exhibition held in Lagos, Nigeria, 5-7 August; 2014.
18. Strong J. Thomas FB. Bennion DB. Reservoir fluid sampling and recommendation techniques for laboratory experiments. Paper CIM 9354 presented at the annual Technical Conference in Calgary, 9-12 May; 1993.
19. International Human Resources Development Corporation (IHRDC) and International Petroleum Industry Multimedia System (IPIMS); 2013. Available:<http://www.ihrdc.com>
20. PVT sim Software, Calsep; 2012. Available:<http://www.pvtsim.com>
21. Imo-Jack O, Emelle C. An analytical approach to consistency checks of experimental PVT data. Paper SPE 167560 presented at the Nigerian Annual International Conference and Exhibition held in Lagos, Nigeria, 30 July–1 August; 2013.
22. Bengherbia M, Tiab D. Gas-condensate well performance using compositional simulator: A case study. Paper SPE 75531 presented at the SPE Gas Technology Symposium, Calgary, Canada, 30 April–2 May; 2002.
23. Hoffman AE, Crump JS, Hocott CR. Equilibrium constants for a gas-condensate system. Petroleum Transactions, AIME. 1953;198:1-10.
24. Soreide I. Improved phase behavior prediction of petroleum reservoir fluids from a cubic equation of state. Dr. Techn. Theses Norwegian Institute of Technology, Department of Petroleum Engineering; 1989.
25. Trengove RD, Hann JH, Skates JR. The impact of PVT data quality on hydrocarbon recovery predictions SPE 22988 prepared for presentation at the SPE Asia Pacific Conference held in Perth Western Australia, 4-7 November; 1991.

© 2015 Akpabio et al.; This is an Open Access article distributed under the terms of the Creative Commons Attribution License (<http://creativecommons.org/licenses/by/4.0>), which permits unrestricted use, distribution, and reproduction in any medium, provided the original work is properly cited.

*Peer-review history:*  
The peer review history for this paper can be accessed here:  
<http://sciencedomain.org/review-history/10630>