Theoretical and experimental determination of initial reservoir fluid in a lean gas condensate reservoir

M. Bonyadi [a,*], F. Esmaeilzadeh [b], D. Mowla [b], M. Nematollahi [b]

[a] Chemical Engineering Department, School of Engineering, Yasouj University, Yasouj, Iran
[b] School of Chemical and Petroleum Engineering, Shiraz University, Shiraz, Iran

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ABSTRACT

In this work, a new theoretical and experimental method has been proposed to obtain initial reservoir fluid from well head separator samples in a depleted lean gas condensate reservoir.

Condensate stabilization technique (CST) is a new recombination method based on simultaneous matching of dew point pressure and gas condensate ratio of initial reservoir fluid. The proposed method is applied to a real lean gas condensate reservoir in Iran, namely Jahroom. The modified Esmaeilzadeh–Roshanfekr equation of state and the Genetic Algorithm in MATLAB environment are used to simulate the CST method. The reservoir depletion process has been simulated by the constant volume depletion test. For nine pressure steps in the CVD test the proposed method was applied on separator samples. The average absolute deviation for composition of the recombined samples was found to be less than 3.5%. The proposed method was also experimentally checked by applying on the Jahroom separator samples. The experimental results show that the absolute deviation of 3.5% for the gas–condensate ratio (GCR) and 1.72% for the dew point pressure are achieved. Additionally, the average absolute deviation for composition of the recombined sample was found to be 4%. The results of calculation and experiment show that the proposed recombination method can produce a fluid with a similar phase behavior of initial reservoir fluid with an acceptable accuracy.

1. Introduction

Samples representing the initial reservoir fluids have always been one of the major challenges in reservoir engineering, particularly in gas condensate reservoirs. Obtaining representative reservoir fluid samples has become of increasing importance in the development and exploitation of oil and gas condensate reservoirs. This is especially true of reservoirs where extensive computer simulations are used to scope out developmental strategies or where enhanced oil recovery options are investigated. Therefore it is imperative that the fluid samples used to make these decisions closely match the characteristic properties of the reservoir fluids at actual reservoir conditions.

For undersaturated reservoirs, representative initial reservoir fluid can be obtained by recombining surface separator samples with the well head gas–condensate ratio (GCR). However, in saturated gas condensate reservoirs this recombination technique cannot be used to obtain the original reservoir fluid. The condensate bank builds up around the producing well when the bottom-hole pressure drops below the dew point pressure. As the reservoir pressure declines, the bank grows and the well produces less heavy components at the surface. Because of multiphase flow in the near wellbore region, even during early depletion stages, recombined separator samples may not represent original reservoir fluid.

The heavy components (C_{7+} fraction) of the reservoir fluids play a dominant role in determining the PVT behavior of the fluid. For example, in a gas condensate fluid the dew point pressure is a strong function of C_{7+} molecular weight and its relative amount in the fluid. Elsharkawy (2002) showed that the dew point pressure increases with the increase of molecular weight, density and mole fraction of C_{7+} fraction. McCain and Alexander (1992), using compositional reservoir simulation, showed that gas samples should be obtained over the first 30 days of production in order to obtain a sample with in-situ reservoir phase behavior.

Reffstrup and Olsen (1994) studied fluid compositional changes during surface sampling. They used a modified black oil simulator and the EOS model to simulate the recombination of separator samples. The authors showed that the dew point pressure of a recombine sample was lower than the initial dew point of reservoir. The procedure suggested by Reffstrup and Olsen for obtaining original reservoir fluid is to first characterize the produced well stream mixture with an EOS, and then calculate

* Corresponding author. Tel./fax: +98 741 2221711.
E-mail addresses: Bonyadi@yu.ac.ir, Bonyadi80@gmail.com (M. Bonyadi), esmaeil@shirazu.ac.ir (F. Esmaeilzadeh), Mowla@shirazu.ac.ir (D. Mowla).

incipient oil composition at well stream dew point pressure. A new mixture is created by adding primary oil to the well stream until the dew point equals the initial reservoir pressure. They noted that several contacts may be required in this procedure.

Fevang and Whitson (1994) extended Reffstrup and Olsen's method to cover other types of reservoirs. They proposed a laboratory method called the equilibrium contact method (ECM) to obtain the original fluid from collected samples, based on their simulation results. In this method collected samples are brought to equilibrium at specified conditions and resulting phases are treated as the original reservoir fluids in oil and gas reservoir. In the contact method, offered by Reffstrup and Olsen (1994) and extended to other reservoir types by Fevang and Whitson (1994), the produced surface separator samples are recombined at the measured GOR first. Then, the resulting well stream fluid is brought to equilibrium at the average bottom-hole pressure and temperature. The liquid phase is removed and added back to the gas to match its dew point pressure to the initial reservoir value.

This paper describes a new experimental procedure (condensate stabilized technique (CST)) for determining original reservoir fluid in a depleted gas condensate reservoir based on simultaneous matching of dew point pressure and gas condensate ratio of the initial reservoir fluid. The main feature of the CST is it is independent of current producing GOR. The proposed recombination method was applied to a real lean gas condensate reservoir in Iran, namely Jahroom.

2. Recombination modeling

2.1. Reservoir description

Jahroom gas condensate reservoir, discovered in 1972 by drilling exploration well JA1, is located 20 km away from Bandar-Abbas in south of Iran. The reservoir temperature is 382 K. The available data of upper Jahroom reservoir fluid are initial composition, initial and dew point pressures of 36.2 MPa and 34.34 MPa with a producing condensate–gas ratio(CGR) of 5565.4 m^3/m^3 (32 STB/MMSCF), respectively. The pressure and temperature of the test separator in 1972 was 6.76 MPa and 309.8 K, respectively. At the current reservoir pressure (19 MPa) separator gas and condensate were obtained from South Zagros Oil and Gas Production Company (Shiraz, Iran). The initial and separator's samples compositions are given in Tables 1 and 2.

2.2. Equation of state

The modified Esmaeilzadeh–Roshanfekr equation of state (ER) (Bonyadi and Esmaeilzadeh, 2008) is used to simulate the recombination process. The modified ER EOS is a new three-parameter equation of state that was developed in 2008 with special attention to application for reservoir fluids. The authors showed that the modified EOS predicts the dew point pressure and bubble point pressure with best accuracy among the other EoSs.

The three-parameter modified ER-EOS has the following form:

$$P = \frac{RT}{v-b} - \frac{a(T)}{v(v+c)+c(v-c)} \tag{1}$$

where R is the universal gas constant, "a" is a function of temperature and "b" and "c" are constants. For a pure compound

$$a(T) = \Omega_a \left(\frac{R^2 T_C^2}{P_C} \right) \alpha(T_r) \tag{2}$$

$$b = \Omega_b \left(\frac{RT_C}{P_C} \right) \tag{3}$$

$$c = \Omega_c \left(\frac{RT_C}{P_C} \right) \tag{4}$$

For a detailed description of the modified Esmaeilzadeh–Roshanfekr equation of state, the reader is referred to the original article (Bonyadi and Esmaeilzadeh, 2008). To predict mixture properties, the van der Waals mixing rules are used.

2.2.1. Tuning

Equations of state (EOS) often fail to predict accurately the phase behavior of a reservoir hydrocarbon fluid. Predictions can be improved by tuning EOSs with some measured data of the fluid. The heavy components in the petroleum mixtures have the strongest effect on the characteristics of fluids (McCain, 1993).

Table 1
Initial reservoir composition (T=382 K, P=36.4 Mpa).

Component	Mol%
N_2	4.65
CO_2	0.55
C_1	85.31
C_2	3.62
C_3	1.53
i-C_4	0.45
n-C_4	0.63
i-C_5	0.35
n-C_5	0.28
C_6	0.45
C_{7+}	2.14
Sp. Gr. C_{7+}	0.79
MW C_{7+}	135

Table 2
Jahroom's separator samples (T=309.8 K and P=6.76 Mpa).

Components	Separator gas sample Mol%	Separator condensate sample Mol%
N_2	4.90	0.30
CO_2	0.49	0.11
C_1	88.1	19.09
C_2	3.73	3.72
C_3	1.26	4.33
iC_4	0.41	2.16
nC_4	0.51	3.7
iC_5	0.21	3.59
nC_5	0.19	3.81
C_6	0.24	9.31
C_{7+}	0.02	49.88
Sp. Gr. C_{7+}	0.705	0.76
MW C_{7+}	114.55	118.46

Table 3
The values of tuned parameters.

Binary interaction coefficients				Critical pressure of C_{7+} MPa	Critical temperature of C_{7+} K	Acentric factor of C_{7+}
C_{7+}, N_2=0.012	C_{7+}, CO_2 =0.01	C_{7+}, C_1 =0.0012	C_{7+}, C_2 =0.44	2.88	669.26	0.49