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Volatile oil well test analysis: application of two-phase pseudo-pressure approach

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Abstract

This study investigates flow behavior in the volatile oil reservoirs with two-phase flow around the wellbore and the application of two-phase pseudo-pressure function for well test analysis in such volatile oil reservoirs. To this end, flow behavior and saturation profile of the volatile oil reservoirs with flowing bottom-hole pressure below the bubble point pressure are investigated using a synthetic reservoir model. Subsequently, well test behavior of this reservoir in drawdown and buildup tests are examined. Finally, the application of two-phase pseudo-pressure concept is examined for analyzing well test data of the volatile oil reservoir. It is shown that two-phase flow near the wellbore causes a composite behavior in well test data with decreasing mobility during drawdowns and increasing mobility during buildups. Moreover, employing normalized two-phase pseudo-pressure function introduced in this study is found to be a suitable method for well test analysis in volatile oil reservoirs. Using the aforementioned method, effective permeability and wellbore skin are estimated by eliminating the effect of gas saturation on the well test results.

Keywords Volatile oil reservoir · Two-phase well test · Two-phase pseudo-pressure · Radial composite behavior

Introduction

Volatile crude oils are characterized by high liquid shrinkage immediately below the bubble point pressure (P_b). These oils contain relatively few heavy hydrocarbon molecules and more intermediate ones compared to black oil (Ahmed 2010). In volatile oil reservoirs, decreasing the bottom-hole pressure (P_{wf}) below the P_b of the reservoir fluid causes vaporizing the dissolved gas in the oil and increasing gas saturation near the wellbore. The liberated gas is immobile initially, but gas saturation increases after a short period of time and flows toward the well (Sharifi and Ahmadi 2009; Sanni and Gringarten 2008). Gas liberation can create three regions with different gas saturations near the wellbore as shown in Fig. 1. In regions 1 and 2, the pressure has dropped below P_b and gas liberates from oil phase. In region 1, gas saturation is higher than critical gas saturation and flows simultaneously with oil toward the wellbore. But in region 2, gas saturation is below the critical value and it is immobile. Region 3 with pressure above the P_b is a single-phase oil region. Regions 1 and 2 are known as gas bank in the literature. The extent of these regions depends on reservoir pressure and oil composition (Sharifi and Ahmadi 2009). This behavior is similar to gas condensate systems with flowing bottom-hole pressure below the dew point pressure. In gas condensate reservoirs, a fourth region may also exist in the vicinity of the wellbore where low interfacial tension at high velocities causes decrease in oil saturation and increase in relative permeability of gas (Gringarten et al. 2000). Later studies showed that this effect is more pronounced with gas condensate fluids than with volatile oils (Ogunrewo et al. 2013). However, since there is no firm understanding about the existence of this region in volatile oil reservoirs (Sharifi and Ahmadi 2009; Sanni and Gringarten 2008), it is not considered in the present study.

The existence of two-phase flow region near the wellbore causes decrease in the mobility of gas/oil, and therefore, the pressure–derivative curve of a homogenous system behaves like a "composite" system. The first region is the altered region with reduced effective permeability due to two-phase

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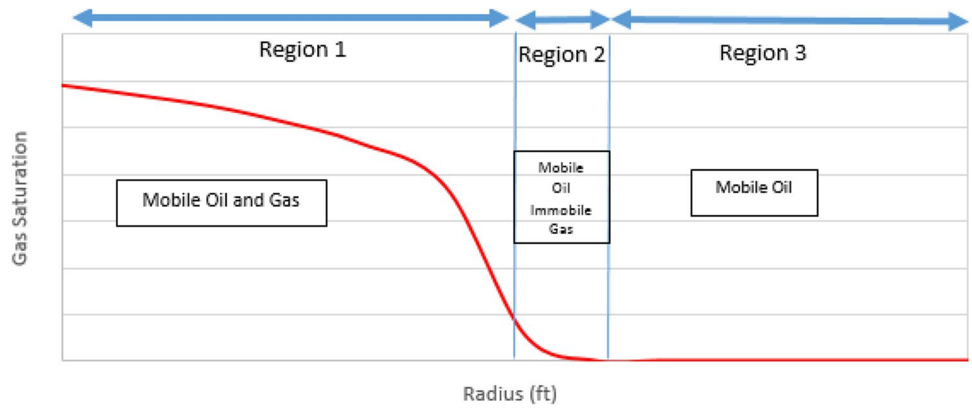

Fig. 1 Gas saturation in typical volatile oil reservoir

gas–oil flow. The second region is the virgin zone with original permeability (Gringarten et al. 2006).

Well test data of volatile oil reservoirs with P_{wf} below the P_b could be analyzed by two approaches. The first method, i.e., radial composite method, uses the pressure data for well test analysis directly. This method calculates effective permeability, skin, gas bank radius, and distance to the fault/boundary approximately. An important issue in using this method is that the duration of the test should be long enough so that the pressure response reaches beyond the two-phase region (Gringarten et al. 2006). If the test duration is not long, the reservoir parameters could not be estimated correctly. Moreover, in radial composite models for oil and gas, the diffusivity equations are not linear and the results are not unique. Therefore, the estimated parameters are less reliable (Mazloom et al. 2004). In the second method, the two-phase pseudo-pressure technique is employed. Two-phase pseudo-pressure approach was first suggested by Raghavan (1976) for solution gas drive reservoirs, like the one introduced for real gas flow by Al-Hussainy et al. (1966). Raghavan definition was initially used by Fetkovich (1973) to define a well's productivity and later on, it was described in more detail by Raghavan (Jones and Raghavan 1988; Raghavan 1989).Using the two-phase pseudo-pressure approach, near-wellbore effects caused by two-phase flow will be eliminated. Therefore, conventional methods developed for well test analysis of single-phase oil reservoirs could be used accurately. This method and the suggested improvements in its calculation procedure are discussed in more detail in the subsequent sections.

The flow behavior and well test interpretation of gas condensate systems by the above-mentioned methods have been widely discussed in the literature (Gringarten et al. 2000, 2006; Bozorgzadeh and Gringarten 2006; Xu and Lee 1999; Mazloom and Rashidi 2006; Yousefi et al. 2014; Shahbazi et al. 2016). However, limited publications deal with volatile oil reservoirs below the P_b (Sharifi and Ahmadi 2009; Sanni and Gringarten 2008). In this study, the application of two-phase pseudo-pressure method for well test analysis of volatile oil reservoir is discussed by using synthetic test data generated by a commercial reservoir simulator. To this end, a synthetic reservoir model is built, and then, flow behavior and saturation profile of volatile oil reservoir with P_{wf} below the P_b is investigated. Subsequently, well test behavior of this reservoir in drawdown and buildup tests are examined. Finally, the application of the two-phase pseudo-pressure concept is examined for well test interpretation of volatile oil reservoirs.

Two-phase pseudo-pressure method

In the conventional method for interpretation of well test data, it is assumed that diffusivity equation is linear, which is valid just for single-phase flow of slightly compressible fluids. Flow equations are then obtained by solving the diffusivity equation with different methods. In a gas condensate reservoir with two-phase flow near the well, diffusivity equation is not linear. But it could be linearized by using a two-phase pseudo-pressure function as presented in Eq. (1). This equation is applied to change a two-phase fluid flow into an equivalent single-phase flow (Raghavan 1976).

$$m(p) = \int_{P_{wf}}^{P} \frac{K_{ro}}{\mu_o B_o} \mathrm{d}p \tag{1}$$

where K_{ro} is oil relative permeability, μ_o is oil viscosity (cp), B_o is oil formation volume factor (m^3/Sm^3), P and P_{wf} are pressure and flowing wellbore pressure (Pa), and $m(p)$ is two-phase pseudo-pressure function.

Similar to gas condensate reservoirs, in a volatile oil reservoir with P_{wf} below P_b, diffusivity equation could be linearized using a two-phase pseudo-pressure function. Therefore, the well-known methods for well test interpretation in black oil reservoirs can be employed for volatile oil reservoirs.

To evaluate $m(p)$, the oil and gas relative permeabilities as a function of pressure should be known. Different approaches have been developed for this purpose in the literature. The steady-state theory initially developed by O'dell and Miller (1967), and modified by Fussell (1973) was employed by Chopra and Carter (1986), Jones and Raghavan (1988) and Raghavan (1989). This theory ignores the transition zone, where the flowing fluid composition is changing. Fevang and Whitson (1996) extended the previous work and used a unique pseudo-pressure function for every region (three-zone method) to account for all three regions. To calculate two-phase pseudo-pressure by Fevang and Whitson method, the pseudo-pressure function is splitted into three components for the three regions introduced earlier. The main assumption in this method is the steady-state assumption for reservoir fluid, except in region 2 where one phase is immobile. This means that the composition of recovered fluid is constant during two-phase flow. The two-phase pseudo-pressure equation developed by Fevang and Whitson (1996) for a gas condensate reservoir is defined as follows:

$$m(p) = \int_{P_{\mathrm{wf}}}^{P^*} \left(\frac{K_{\mathrm{rg}}}{\mu_{\mathrm{g}} B_{\mathrm{g}}} + \frac{R_{\mathrm{s}} K_{\mathrm{ro}}}{\mu_{\mathrm{o}} B_{\mathrm{o}}} \right) \mathrm{d}p + \int_{P^*}^{P_{\mathrm{dew}}} \frac{K_{\mathrm{rg}}}{\mu_{\mathrm{g}} B_{\mathrm{g}}} \mathrm{d}p + K_{\mathrm{rg}}(S_{\mathrm{wi}}) \int_{P_{\mathrm{dew}}}^{P} \frac{1}{\mu_{\mathrm{g}} B_{\mathrm{g}}} \mathrm{d}p \tag{2}$$

For a volatile oil reservoir, the above equation can be written as:

$$m(p) = \int_{P_{\mathrm{wf}}}^{P^*} \left(\frac{K_{\mathrm{rg}} R_{\mathrm{v}}}{\mu_{\mathrm{g}} B_{\mathrm{g}}} + \frac{K_{\mathrm{ro}}}{\mu_{\mathrm{o}} B_{\mathrm{o}}} \right) \mathrm{d}p + \int_{P^*}^{P_{\mathrm{b}}} \frac{K_{\mathrm{ro}}}{\mu_{\mathrm{o}} B_{\mathrm{o}}} \mathrm{d}p + K_{\mathrm{ro}}(S_{\mathrm{wi}}) \int_{P_{\mathrm{b}}}^{P} \frac{1}{\mu_{\mathrm{o}} B_{\mathrm{o}}} \mathrm{d}p \tag{3}$$

where K_{r} is relative permeability for gas (g) and oil (o), μ is viscosity (cp), R_{s} is solution gas oil ratio (m^3/m^3), R_{v} is solution oil gas ratio (m^3/m^3), B is fluid formation volume factor (m^3/Sm^3), S_{wi} is initial water saturation, and P_{b} and P_{dew} are bubble point pressure and dew point pressure, respectively (Pa). Subscripts g and o denote for gas and oil, respectively.

In Eqs. (2) and (3), the first integral is for region 1 where oil and gas are mobile. The second and the third ones are used for regions 2 and 3, respectively. Based on this method, P^*, the outer boundary pressure of region 1 can be assumed as the P_{b} of the flowing wellbore stream in a volatile oil reservoir.

In this study, "normalized two-phase pseudo-pressure" is applied with same dimension as pressure, instead of "two-phase pseudo-pressure". Normalized two-phase pseudo-pressure can be obtained by multiplying the two-phase pseudo-pressure by oil viscosity and formation volume factor at average reservoir pressure (Eq. 4). Hence, its dimension becomes same as pressure and the interpretation results using normalized two-phase pseudo-pressure can be compared with those of single-phase pressure in a single plot.

$$m_{\mathrm{n}}(p) = (\mu_{\mathrm{oi}} B_{\mathrm{oi}}) * \left[\int_{P_{\mathrm{wf}}}^{P^*} \left(\frac{K_{\mathrm{rg}} R_{\mathrm{v}}}{\mu_{\mathrm{g}} B_{\mathrm{g}}} + \frac{K_{\mathrm{ro}}}{\mu_{\mathrm{o}} B_{\mathrm{o}}} \right) \mathrm{d}p + \int_{P^*}^{P_{\mathrm{b}}} \frac{K_{\mathrm{ro}}}{\mu_{\mathrm{o}} B_{\mathrm{o}}} \mathrm{d}p + K_{\mathrm{ro}}(S_{\mathrm{wi}}) \int_{P_{\mathrm{b}}}^{P} \frac{1}{\mu_{\mathrm{o}} B_{\mathrm{o}}} \mathrm{d}p \right] \tag{4}$$

where $m_{\mathrm{n}}(p)$ is normalized two-phase pseudo-pressure, μ_{oi} and B_{oi} are oil viscosity and oil formation volume factor at average reservoir pressure. To evaluate the integrals in Eq. (4), the relation between relative permeability and pressure should be known. The relative permeability curve presents the relation between relative permeability and oil saturation. Hence, the relation between pressure and saturation should be obtained for each region. One of the following three methods can be used for saturation estimation as a function of pressure:

1. Using the tuned EOS with experimental data.
2. Using Fetkovich et al. (1986) steady-state formula for calculating gas/oil relative permeability ratio and estimating the saturation at the desired pressure by comparing the obtained relative permeability ratio with experimental gas and oil relative permeability data which has been measured at different oil saturations.

   $$\frac{k_{\mathrm{rg}}}{k_{\mathrm{ro}}}(p) = \left(\frac{R_{\mathrm{p}} - R_{\mathrm{s}}}{1 - R_{\mathrm{v}} R_{\mathrm{p}}} \right) \frac{\mu_{\mathrm{g}} B_{\mathrm{g}}}{\mu_{\mathrm{o}} B_{\mathrm{o}}} \tag{5}$$

   where R_{p} is producing gas oil ratio (m^3/m^3).This equation is valid for region 1 where gas saturation is higher than the critical saturation and two-phase flow exists near the wellbore. In Eq. (5), besides R_{p} which is constant, all other parameters in the right-hand side depend on pressure. Using relative permeability curves, the following relation can be inferred:

   $$\frac{k_{\mathrm{rg}}}{k_{\mathrm{ro}}} = f(S_{\mathrm{o}}) \tag{6}$$

   Using Eqs. (5) and (6), an implicit relationship between pressure and oil saturation is provided.
3. Estimating oil saturation at shut-in pressure with the equation developed by Bøe et al. (1989, Mazloom et al. 2005):

$$\frac{dS_o}{dP} = \frac{S_o}{B_o}\frac{dB_o}{dP} + \frac{\lambda_o}{\lambda_t}\left\{ -\frac{S_o}{B_0}\frac{dB_o}{dP} + \frac{S_o(B_g - R_v B_o)}{B_o}\frac{dR_s}{dP} + \frac{-S_g}{B_g}\frac{dB_g}{dP} + \frac{S_g(B_o - R_s B_g)}{B_g}\frac{dR_v}{dP} \right\} \quad (7)$$

where S_o is oil saturation, S_g is gas saturation, λ_o is oil mobility, and λ_t is total mobility which is given by:

$$\lambda_t = \lambda_o + \lambda_g = \frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} \quad (8)$$

This equation is used for distances away from the wellbore where the gas is immobile (region 2).

The first method is applicable only for short duration tests in which the gas saturation near the wellbore is below its critical value. In this case, the PVT properties of original fluid can be used since fluid sample and well test data are obtained simultaneously, and in short duration tests, fluid composition remains constant. The second method, i.e., Fetkovich correlation (Fetkovich et al. 1986) for region 1, is more accurate for estimating oil saturation than the other two methods. However, this method requires the gas and oil relative permeabilities. The third method provides oil saturation for long duration tests. In this case, fluid composition varies with time, and the oil saturation around the wellbore is best evaluated from PVT properties of the produced fluid at production time (Bozorgzadeh and Gringarten 2006).

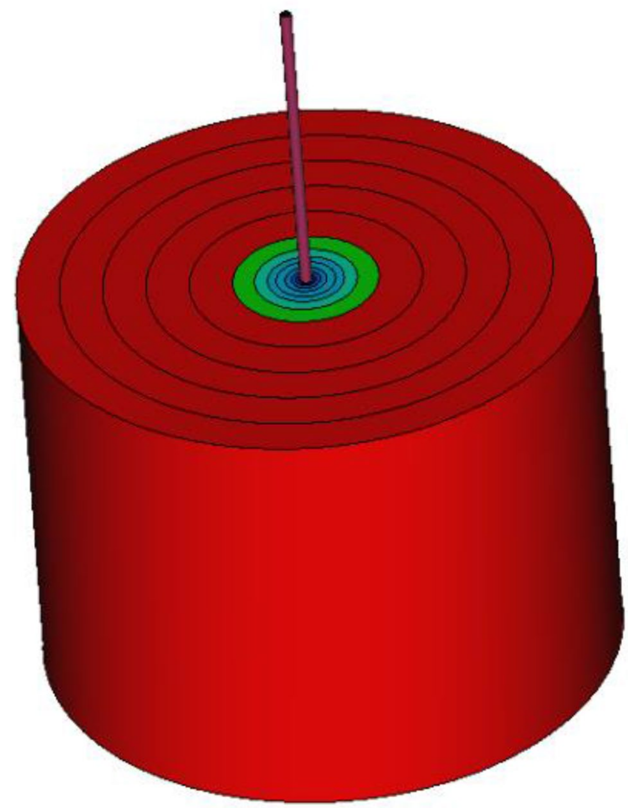

Fig. 2 Schematic of the model

Model construction

A synthetic reservoir model is used to study well test behavior of volatile oil reservoirs with the P_{wf} below P_b. The reservoir is a homogenous radial model with constant thickness as shown in Fig. 2. Table 1 presents the reservoir model parameters. The model was built with 48 cells in radial direction. To obtain fluid and pressure behavior accurately near the well, grid size was increased logarithmically in the radial direction, with smaller grids near the wellbore and larger ones away. The outer radius of the model was considered large enough to ensure that well test data are not affected by the outer boundary. High-resolution time steps were used, especially at the start of each test duration to provide smooth saturation profiles and linear pressure gradients. A volatile oil with P_b of 33.58 MPa and 311 m^3/m^3 solution gas–oil ratio at P_b was used in the model. Modified Peng–Robinson equation of state (EOS) with three parameters was applied for modeling fluid PVT properties.

Successive 5-day drawdowns and 5-day buildups (DD1, BU1, DD2, and BU2), were designed and simulated to produce well test data and interpret it in two-phase flow conditions. Figure 3 shows pressure and rate histories for a typical simulation run (case 1). Subsequently, other cases were also run and simulated with different reservoirs and fluid parameters to investigate the effect of changing reservoir parameters on the well test results.

During drawdown test in a volatile oil reservoir, when P_{wf} drops below the P_b, a zone with high gas saturation is created near the wellbore with simultaneous oil and gas flow, whereas only single-phase flow of oil exists far from the wellbore with the initial gas saturation (Fig. 4).

During the following buildup, gas saturation near the wellbore from the previous drawdown depends on the average reservoir pressure. If the average reservoir pressure is close to the bubble point pressure [e.g., case 1 with initial pressure (Pi) of 34 MPa and P_b of 33.58 MPa], the liberated gas cannot condense into the oil and remains as a separate phase as shown in Fig. 5. But if the difference between these two pressures is high enough (e.g., case 2 with initial pressure of 38 MPa and P_b of 33.58 MPa), the liberated gas condenses into the oil, and gas saturation around the wellbore returns to the initial value during the buildup as shown in Fig. 6. In fact, the above-mentioned behavior depends on the saturation pressure of fluid near the wellbore which varies because of fluid composition changes during production (Fig. 7). Therefore, if the

Table 1 Model parameters

Parameter	Value	Parameter	Value
Porosity (%)	9	Reservoir temperature (°C)	146
Absolute permeability (m^2)	4.93E−15	Initial reservoir pressure (MPa)	34
Net-to-gross ratio	1	Initial water saturation	0
Wellbore radius (m)	0.08	Residual oil saturation	10%
Top depth (m)	3048	Critical gas saturation	5%
Reservoir thickness (m)	30.48		

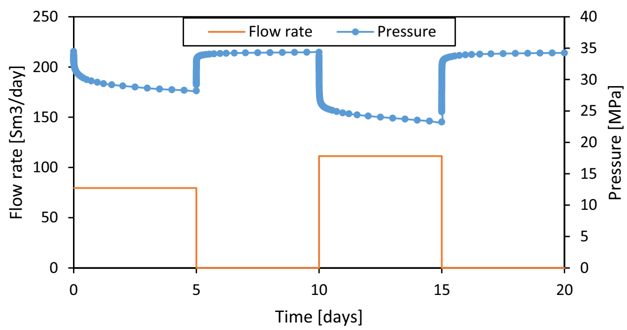

Fig. 3 Pressure and rate histories (case 1)

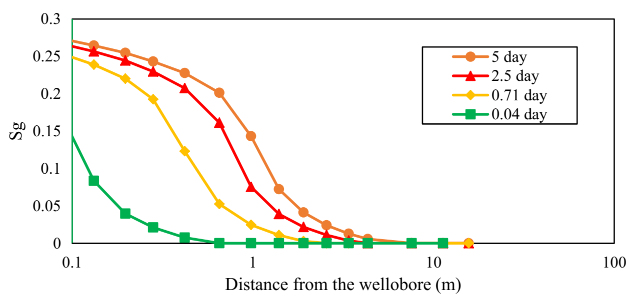

Fig. 4 Gas saturation profile around the wellbore in DD1 test at different times from start of production (case 1)

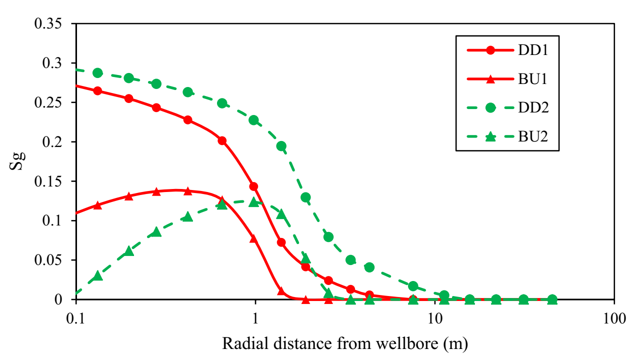

Fig. 5 Gas saturation profile at the end of DDs and BUs below P_b in case 1 (Pi = 34 MPa)

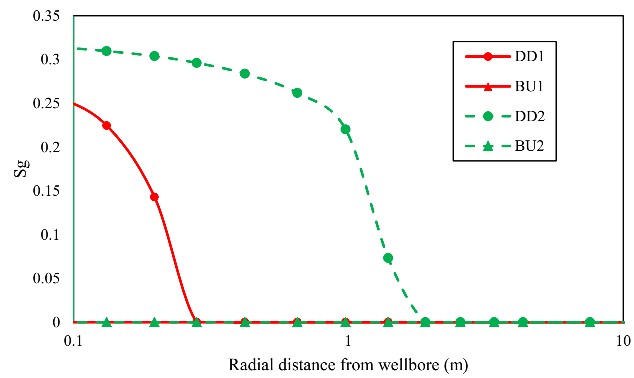

Fig. 6 Gas saturation profile at the end of DDs and BUs below P_b in case 2 (Pi = 38 MPa)

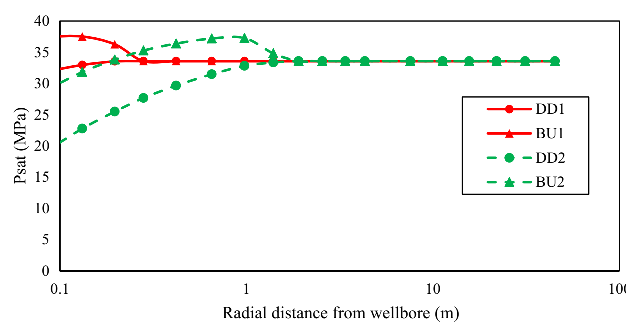

Fig. 7 Saturation pressure profile for flow periods at the end of drawdown and buildup tests (case 1)

buildup pressure is above the altered saturation pressure of near-wellbore fluid, the liberated gas dissolves into oil during the buildup test, otherwise it remains as a separate gas phase.

Well test analysis

In volatile oil reservoirs, when P_{wf} is above P_b, they have same trends as black oils in drawdown and buildup tests. Hence, their mobility can be evaluated using a method similar to black oils. Below P_b, at the end of drawdown, lower relative mobility of oil is observed as shown in

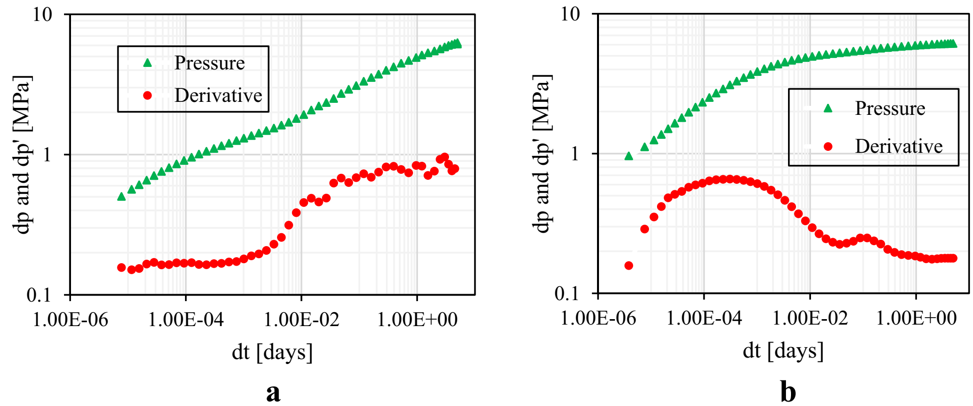

Fig. 8 Log–log pressure and derivative; **a** DD1 test, **b** BU1 test case 1

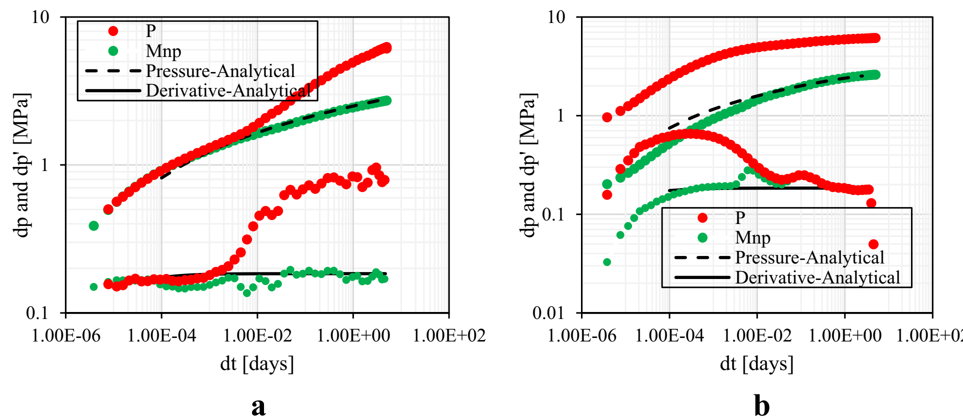

Fig. 9 Log–log pressure and derivative (single-phase pressure vs normalized two-phase pseudo-pressure in case 1; **a** DD1 test, **b** BU1 test)

Fig. 8a with higher late time derivative stabilizations of drawdown test. Subsequently, at the beginning of buildups, lower relative mobility of oil is observed as shown in Fig. 8b with higher early time derivative stabilizations of buildup test. In drawdown test, liberation of gas near the wellbore decreases oil effective permeability. Moreover, the amount of light hydrocarbons in oil decreases during drawdown causing oil viscosity to rise. Therefore, the mobility of oil decreases due to combined effects of decrease in effective permeability and increase in oil viscosity. In buildup test, pressure rise causes dissolution of gas into oil which increases effective permeability and reduces oil viscosity. Therefore, the mobility of oil increases with time. Consequently, the log–log pressure–derivative behavior of volatile oil reservoirs below P_b matches to the two-zone radial composite model, with decreasing mobility in drawdowns (Fig. 8a) and increased mobility in buildups (Fig. 8b).

In this section, the reliability of two-phase pseudo-pressure method for analyzing volatile oil reservoirs is investigated. To this end, "normalized two-phase pseudo-pressure" was calculated and employed for interpretation. The Fetkovich et al. (1986) method was used for saturation estimation in region 1, and the correlation developed by the Boe et al. (1989) was used in region 2. Figure 9 shows the results of DD1 and BU1 tests in case 1 on log–log plots. In this case, the initial reservoir pressure was 34 MPa and the bottom-hole pressure reached to 28 MPa at the end of DD1. As can be seen in Fig. 9, by using normalized two-phase pseudo-pressure, the near-wellbore effects caused by gas liberation are removed from log–log derivative plots in drawdown and buildup tests. Therefore, the decrease in mobility during drawdown and increase in mobility during buildup which was observed in pressure–derivative plots as discussed previously do not appear in log–log normalized two-phase pseudo-pressure plots. This means that the actual permeability could be estimated using these plots. Moreover, the skin effect determined by the analysis of these data represents the

Table 2 Results of DD1 and BU1 tests using normalized two-phase pseudo-pressure (case 1)

Parameter	Model value	DD test results		BU test results	
		Value	ARE[a] %	Value	ARE %
K (m^2)	4.93E−15	4.93E−15	0.00	4.70E−15	4.67
Sw	0	−0.19	–	−0.41	–

[a]Absolute relative error

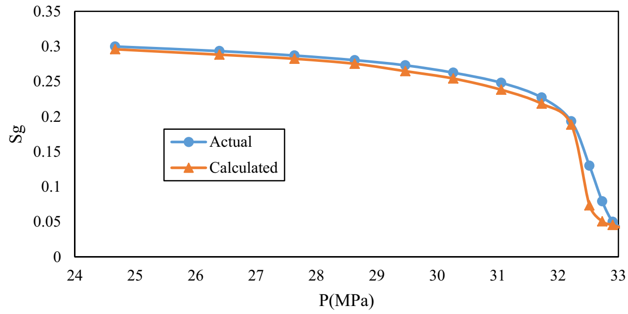

Fig. 10 Actual (model) and estimated saturation profile near the wellbore at the end of DD test (case 1)

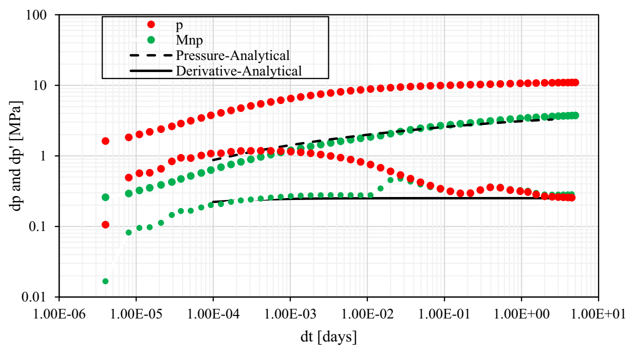

Fig. 11 Log–log pressure and derivative (pressure vs two-phase pseudo-pressure in BU2 test case 1)

Table 3 Results of BU2 test using normalized two-phase pseudo-pressure (case 1)

Parameter	Model value	Well test results	
		Value	ARE %
K (m^2)	4.93E−15	4.82E−15	2.23
Sw	0	−0.95	

wellbore skin (Sw). The results of the analysis for buildup and drawdown tests are presented in Table 2. As can be seen, the estimated parameters are in acceptable range.

To check the accuracy of this method, actual saturation profile near the wellbore was compared with saturation profile estimated by two-phase pseudo-pressure method. Figure 10 shows actual gas saturation profile near the wellbore and the gas saturation profile calculated by two-phase pseudo-pressure method at the end of DD. As can be seen, a good match is obtained between the actual and calculated gas saturation profiles near the wellbore where mobile gas saturation exists. Therefore, it could be considered to be suitable for linearizing flow equation and parameter estimation in well test analysis.

Table 4 Fluid properties

Properties	Case 1 (fluid A)	Case 3 (fluid B)
P_b (MPa)	33.58	28.47
R_s (m^3/m^3)	311.33	50.65
B_o at P_b (m^3/Sm^3)	2.08	2.53

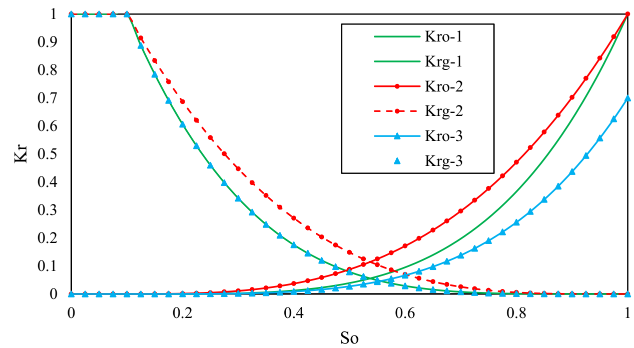

Fig. 12 Relative permeability curves

In order to investigate the effect of production rate on the well test results, data of the second buildup (BU2) in case 1 with a higher production rate (111 Sm^3/Day) were used for analysis by normalized two-phase pseudo-pressure function. The obtained results of this analysis are shown in Fig. 11 and Table 3. The obtained results indicate that permeability and wellbore skin are predicted quite well.

Subsequently, other cases with different fluids with higher volatility (case 3), different relative permeability models (cases 4 and 5), and different wellbore skins (Sw = 5 in case 6, Sw = 10 in case 7) were investigated. Table 4 and Fig. 12 present the changes in fluid and rock properties compared to case 1. In these cases, other parameters are same as case 1. Normalized two-phase pseudo-pressure was used for well test interpretation in all cases. The results are presented in Table 5. As can be seen, match between actual and estimated parameters for all cases is in acceptable range. However, the wellbore skin obtained by this method is slightly underestimated in some cases, especially in wells with higher wellbore skin. The results of two-phase well test analysis of these cases are presented in Fig. 13a for higher volatile fluid (case 3), Fig. 13b, c for different relative permeability models (cases#4 and 5), and Fig. 13d, e for different wellbore skins (Sw = 5 in case 6, Sw = 10 in case 7). It is obvious that the near-wellbore region effects are removed from log–log pressure and derivative plots.

The proposed method was also applied to analyze the well test data in a faulted reservoir. A Cartesian grid having a single layer in z direction and 55 grids in *x*- and *y*-directions was built. Other model parameters and assumptions were

Table 5 Results of BU1 test using normalized two-phase pseudo-pressure in different cases

Parameter	Case 3 (fluid B)		Case 4 (Kr2)		Case 5 (Kr3)		Case 6 (Sw = 5)		Case 7 (Sw = 10)	
	Value	ARE %	Value	ARE %	Value	ARE %	Value	ARE %	Value	ARE %
K (m^2)	5.08E−15	3.04	4.67E−15	5.27	5.07E−15	2.84	4.89E−15	0.81	5.16E−15	4.67
Sw	−0.76	–	−0.41	–	−0.59	–	4.7	6.00	9	10

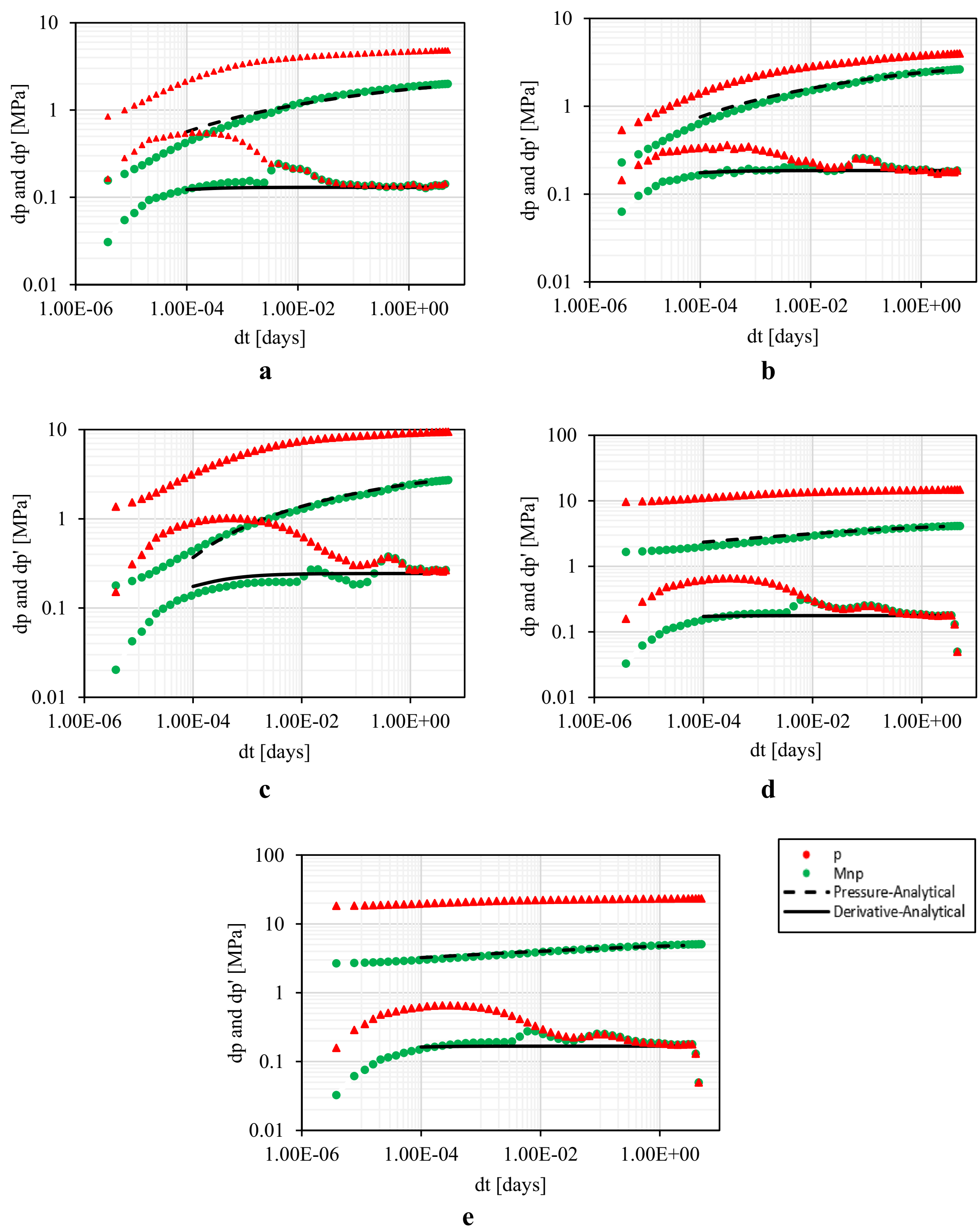

Fig. 13 Log–log pressure and derivative (pressure vs two-phase pseudo-pressure in BU1 test; **a** case 3 (fluid B), **b** case 4 (Kr2), **c** case 5 (Kr3), **d** case 6 (Sw = 5), and **e** case 7 (Sw = 10))

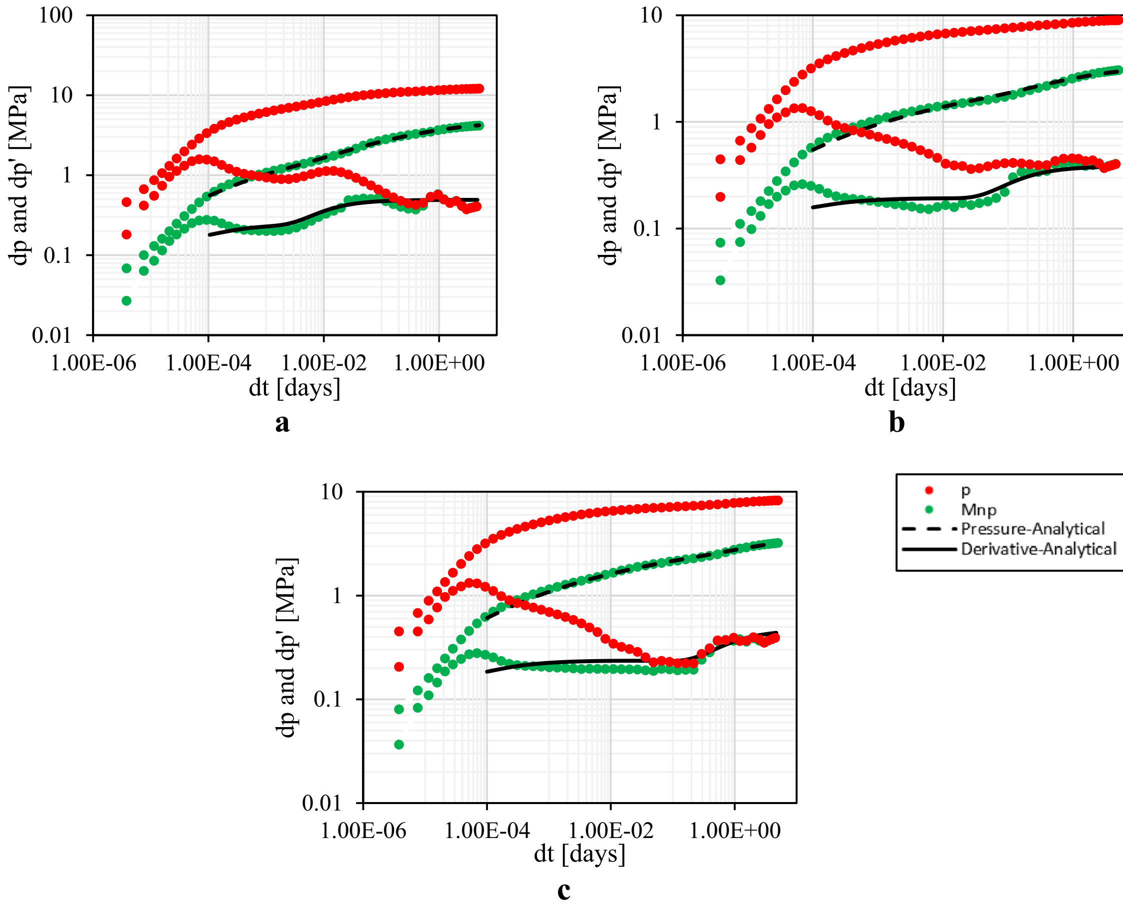

Fig. 14 Comparison of pressure and two-phase pseudo-pressure in faulted reservoir; **a** case 8 ($L=2.74$ m), **b** case 9 ($L=10.67$ m), and **c** case 10 ($L=36.58$ m))

Table 6 Results of BU1 test using normalized two-phase pseudo-pressure in faulted models

Parameter	Case 8 (Fault 1)		Case 9 (Fault 2)		Case 10 (Fault 3)	
	Value	ARE %	Value	ARE %	Value	ARE %
K (m^2)	4.64E−15	6.00	4.77E−15	3.40	4.68E−15	5.20
Sw	−1.05	–	−0.95		−0.80	
L (m)	3.05	11.11	11.58	8.57	39.62	8.33

same as case 1. Three cases were simulated with a fault at different distances from the well. In case 8, the fault is near to wellbore having a distance lower than gas bank outer radius ($L=2.74$ m). In case 9, the fault distance is almost same as the gas bank radius ($L=10.67$ m), and in case 10, its distance is longer ($L=36.58$ m). Figure 14 shows the effect of using normalized two-phase pseudo-pressure on log–log derivative curve. As can be seen, the presence of gas around the wellbore decreases oil mobility and composite behavior of the derivative curve hides the effect of fault in this plot. However, effect of gas bank on the derivative curve has been removed with the use of two-phase pseudo-pressure, and the derivative curve is only representative of reservoir parameters. The fault effect is visible in derivative curve for all cases, and it is possible to calculate the distance to the fault. Table 6 presents the results of well test analysis as well as the actual model parameters. As can be seen, obtained parameters are in good agreement.

Conclusion

In this study, pressure behavior of volatile oil reservoirs with bottom-hole pressure below the P_b is investigated. It was shown that the normalized two-phase pseudo-pressure procedure could be safely employed for interpretation of two-phase volatile oil well test data. Followings also are inferred from this study:

1. During drawdown test of volatile oil reservoirs with flowing bottom-hole pressure below the P_b, a zone with high gas saturation is observed near the wellbore. During subsequent buildup, the liberated gas may condense into the oil, only if the difference between the average reservoir pressure and P_b is high enough.
2. The high gas saturation zone near the wellbore in volatile oil reservoirs causes a composite behavior in well test data, which shows decrease in mobility during drawdowns and increase in mobility during buildups.
3. Employing normalized two-phase pseudo-pressure function introduced in this study is found to be a suitable method for well test interpretation in volatile oil reservoirs, provided that relative permeability and PVT data are available. Using the aforementioned method, the permeability and the wellbore skin are estimated by removing the effect of gas saturation on the well test results.
4. This method was successfully applied for well test interpretation in a faulted reservoir in where the fault lies at the two-phase region and beyond it. The results were satisfactory for all cases.

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