Parametric Investigation of Gas Condensate Mobility versus Permeability in Multiphase Flow Reservoirs

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Abstract

The characterization of the gas condensate reservoir is complicated due to the multiphase flow of the fluid. The change of the composition of the complicate stream further makes it complicated. Such characterization is being done to measure the well performance. To overcome this complexity, rigorous mathematical modelling is suggested for well test analysis. This mathematical modelling can be used to establish the correlation between well test analysis and well performance analysis. The research work is carried out to develop the analytical method to calculate the effective permeability of the gas condensate reservoir, gas condensate mobility and effects of mobility on the effective permeability. Here the different mathematical models are studied during the research work. The other correlations are used to determine the reservoir fluid's properties. Perrine's method is used to estimate reservoir permeability. The research was carried out to analyze the effects of gas condensate mobility on permeability. In this work, the pressure build-up test data is analyzed, effective permeability (k_o), gas condensate mobility and effects of gas condensate mobility are analyzed. This study found effective permeability and mobility by applying Perrine's method mathematical models, oil 14.603 mD, gas 0.148 mD and water 17.159 mD. Using the data obtained through the correlations, the calculated mobility (λ) of the oil, gas and water phase is 126.652 mD/cp, 13.454 mD/cp and 98.671 mD/cp, respectively.

Keywords Gas condensate mobility, multiphase flow, pressure build-up testing, effective permeability.

Introduction

Gas condensate reservoirs have been discovered worldwide, receiving considerable attention in recent years; these reservoirs are different from others in terms of fluid behaviour and production mechanism. In these reservoirs, the production rate depends on bottom hole flowing pressure, which determines the condensate distribution near-wellbore [1]. A reservoir was initially containing natural gas that will accelerate hydrocarbon liquids as the pressure decreases. Gas condensate is a liquid stream of hydrocarbons that has been separated from natural gas and is composed of hydrocarbons with a higher molecular weight that exists in a reservoir as a component of natural gas. Still, It is obtained through separators in the form of liquids—field facilities or gas refineries [2]. Natural gasoline is a term that refers to the higher-molecular-weight hydrocarbons product. Well, test analysis in the gas condensate is complex when the fluid flow towards the wellbore multiphase flow occur, and changes in the composition create problems in the study of well test data [3]. As fluid flows through a gas condensate reservoir, three regions form near the wellbore where both liquid and gas are mobile (first region). In this second region, both liquid and gas are available. Still, only gas is mobile (second region), and a third region contains only gas with pressure more significant than the dew point (third region) [4].

This article discusses the performance of gas condensate reservoirs. As the pressure drops in these reservoirs, vapour and liquid phases occur. Phase interference is caused by capillary pressure, which limits gas production [5]. The ratio of effective permeability to apparent fluid viscosity is called mobility [6].

The term "mobility" refers to the ease with which fluid moves through reservoir rock. The ratio of effective permeability to phase Viscosity [8]. The total of the individual phase viscosities determines the overall mobility. The product of mobility and layer thickness product is directly related to productivity [9].

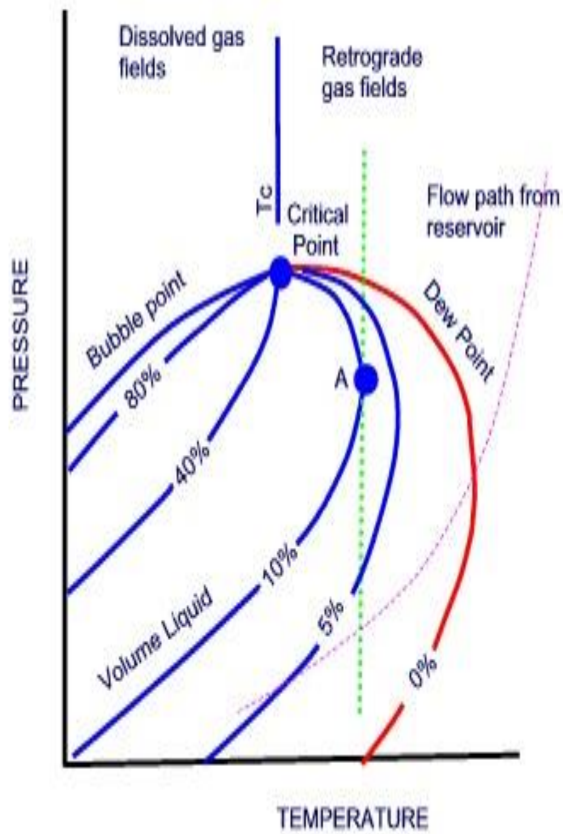

Figure 01. Phase diagram for three-phase gas condensate reservoirs [7]

Research Methodology

Suppose the pressure in a gas condensate reservoir falls below the dew point pressure. In that case, different fluid regions develop around the well—a circular pool formed of concentric areas with a vertical well located at the centre. Three regions in the gas condensate well are shown in Figure No.01. A well is in

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the centre of the gas condensate reservoir. Three distinct fluid zones exist: region 01 contains gas and condensate, whereas region 02 contains gas and condensate. But only gas can flow. In region three, only gas in a single phase exists. Three regions around the well are shown in Figure No. 02.

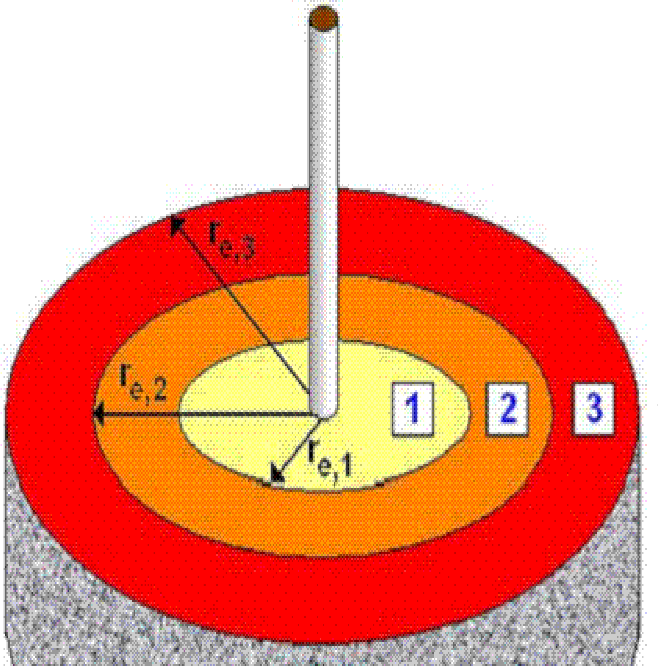

Figure 02. A circular reservoir with three regions.

In the Conceptual model for the multiphase flow of gas condensate reservoir, three regions are shown. In region 01, gas and oil both exist. Initially, the pressure high gas-only flow as pressure drops condensate start to build up will not move until critical saturation is reached as saturation reached both gas and oil cab flow from region 01. In region 02, the saturation of the oil is low as compared to gas. That's why oil can not flow in region 03. The saturation of the oil is equal to zero. Only gas exits. Figure No. 03 illustrates the conceptual model of multiphase flow.

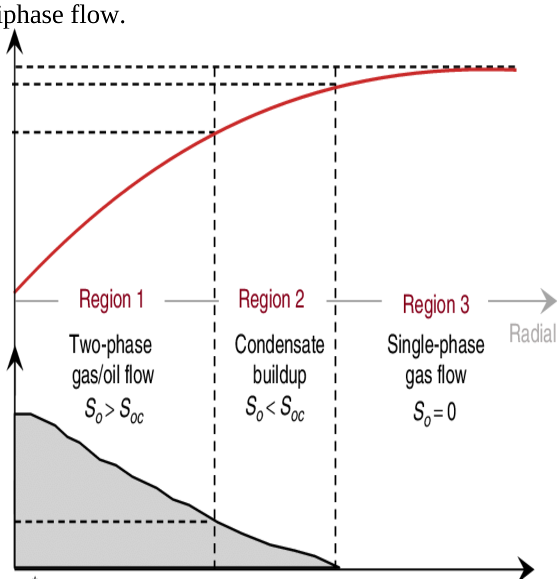

Figure 03. Multiphase flow regions in a condensate reservoir conceptual model [10].

It initially contains natural gas, which accelerates the hydrocarbon liquid as the pressure decreases. Gas condensate is a liquid stream of hydrocarbons separated from natural gas and composed of higher molecular weight hydrocarbons that occur as a component of natural gas in a reservoir but are obtained as a liquid in separators, field facilities or gas refineries [11].

There are a variety of techniques for analysing the results of a build-up test [12]. The most widely used method is Horner's, which is based on the assumption that the reservoir is infinite, which allows for applying the transformed solution for transient flow. Horner's plot predicts a linear relationship between p_{ws} and log $(\frac{t_p+\Delta_t}{\Delta_t})$, presented in Figure. No. 04. as an MTR (*middle transient region*).

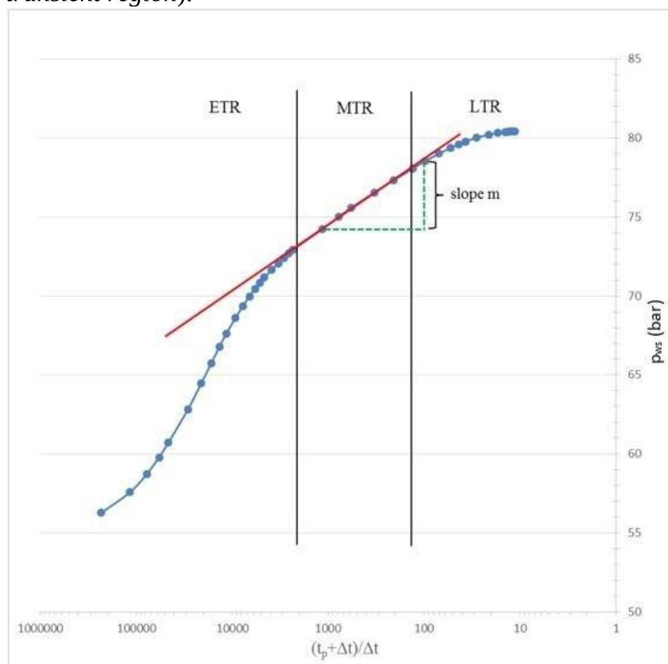

Figure No.04. pressure build-up graph showing early, middle and late time regions [13].

A pressure build test was conducted on the XYZ gas condensate reservoir field, a well flowing under the multiphase in gas condensate reservoir. The pressure build-up test can be modified for the multiphase flow as given below in equation [10, 14] for an infinite acting reservoir.

$P_{ws} = p_i - 162.6\frac{qR_t}{\lambda_t h} log\frac{t_p+\Delta_t}{\Delta_t}$………….. [1]

Where:

P_{ws}= well head pressure at shut in
p_i = initial reservoir pressure
$qR_{t=}$ total well flow rate
λ_t= total mobility of the fluid
h= pay zone thickness
t_p= producing time

In equation [1], *qRt is a constant that equals the total reservoir flow rate (RB/D).*

$qR_t = q_o B_o + \left(q_g - \frac{q_o R_s}{1000}\right) B_g + q_w B_w$………….. [2]

where λ_t represents the total mobility, given by equation [3]

$\lambda_t = \frac{k_o}{\mu_o} + \frac{k_g}{\mu_g} + \frac{k_w}{\mu_w}$………………….. [3]

The mobility is the ration of the effective permeability of the fluid and its density. Which is given by the equation.

According to the preceding equations, mobility can be determined from the slope (m) of a build-up test done on a well-running in multiphase. From equation [1], slope (m) can be calculated.

$m = \frac{162.6q_{Rt}}{\lambda_t h}$……………. [4]

From the above equation [4], mobility can be estimated

$\lambda_t = \frac{162.6qR_t}{mh}$………….. [5]

The permeability for each phase of the fluid can be estimated from the above equation [5]

$k_o = \frac{162.6\ q_o B_o \mu_o}{mh}$……….. [6]

$k_g = \frac{162.6\left(q_g - \frac{q_o R_s}{1000}\right)B_g \mu_g}{mh}$………….. [7]

$k_w = \frac{162.6\ q_w B_w \mu_w}{mh}$……………… [8]

Correlation used for the calculation of PVT properties of the fluids

Critical temperature and pressure calculation [15].

These parameters are needed in Standing and Katz compressibility chart for calculating the compressibility factor (z)

Standing correlation for pseudo critical properties of gas condensate

$$T_{pc} = 168 + 325\gamma_g - 12.5{\gamma_g}^2$$
$$P_{pc} = 706 + 51.7\gamma_g - 11.1{\gamma_g}^2$$

Where

T_{pc} = pseudo critical temperature, °R

P_{pc} = pseudo critical pressure, Psia

γ_g = Specific gravity of the gas mixture

$$P_{pr} = \frac{P}{P_{pc}}$$
$$T_{Pr} = \frac{T}{T_{pc}}$$

Calculate compressibility factor using Standing and Katz compressibility chart

Z (compressibility factor)

B_g calculations using the following equation

$B_g = 0.005035\frac{zT}{P}\ bbl/scf$

1.1.4. *Calculate gas density using the following equation*

$\rho_g = \frac{PM}{RT}$ lb/ft^3

where R denotes the universal gas constant and M represents a gas's molecular weight.

Calculated the gas viscosity using the Lee-Gonzalez-Eakin relationship

$$\mu_g = 10^{-4}Kexp\left[X\left(\frac{\rho_g}{62.4}\right)^Y\right]$$

Where

$$K = \frac{(9.4 + 0.02M_a)T^{1.5}}{209 + 19M_a + T}$$
$$X = 3.5 + \frac{986}{T} + 0.01M_a$$
$$Y = 2.4 - 0.2X$$

$$\mu_g = 10^{-4}Kexp\left[X\left(\frac{\rho_g}{62.4}\right)^Y\right]$$

Calculated R_{so} using the following equation for light oil.

Standing correlation for R_s at a pressure more significant than the bubble point of the crude oil

$$R_s = \gamma_g\left[\frac{P_b}{18(10)^{Y_g}}\right]^{1.2048}$$
$$Y_g = 0.00091(T) - 0.0125API$$

γ_g = Specific gravity of the gas mixture

$$Y_g = 0.00091(354) - 0.0125(50) = -0.30286$$

Calculated vapour phase in the gas phase, R_o $[STB/MMscf]$

$$R_o = -11.66 + 4.706\times10^{-9}{R_s}^3 + 1.623\sqrt{R_s} - \frac{42.3815}{\sqrt{R_s}}$$

Producing gas-oil ratio, R_p, is measured during the well test, 9470 SCF/STB.

Oil properties

Oil formation volume factor (B_o) Standing's correlation

$$B_o = 0.9759 + 0.000120\left[R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25(T - 460)\right]^{1.2}$$

This factor is known as oil formation volume factor; this factor is needed for calculating the effective permeability of the oil phase.

In this equation

T = Temperature, °R

γ_o = specific gravity of the oil in the stock tank

γ_g = specific gravity of the solution gas

2.2.2. Viscosity of oil (μ_o) Beal's correlation

$$\mu_o = \left(0.32 + \frac{1.8(10^7)}{API^{4.53}}\right)\left(\frac{360}{T - 260}\right)^a$$

With

$$a = 10^{\left(0.43 + \frac{8.33}{API}\right)}$$

Where

$\mu_o = Cp\ Viscosity\ of\ oil\ at\ 14.7\ psia\ and\ temperature\ of\ reservoir$

T = Temperature, ^{0}R

2.*3 properties of water*

2.3.1. *Formation volume factor for water*

$$B_w = A_1 + A_2P + A_3P^2$$

Where the coefficients A1 -A2 is defined as follows:

$A_i = a_1 + a_2(T - 460) + a_3(T - 460)^2$

Where a1-a2 denotes free water in Table No. 01.

Table No. 01. Correlation values.

A_i	a_1	a_2	a_3
A_1	0.9947	5.8(10^{-6})	1.02(10^{-6})
A_2	-4.228(10^{-6})	1.8376(10^{-8})	-6.77(10^{-11})
A_3	1.3(10^{-10})	-1.3855(10^{-12})	4.285(10^{-15})

Table No.02. Well and fluid data.

Pi	5,000 psi	H	100 ft
GWR	10,000 CF/STB	C	0.2 STB/psi
WGR	100 STB/MMSCF	S	3
SG	0.7	Kh	100 md-ft
P_d	5,000psi	K	1md
T_p	1000psi	q_g	1MMSCF/D

C_r	$3\times10^{-6}psi^{-1}$	q_o	100STB/D
T	250 ^{0}F	q_w	100 STB/D
GOR	20,000 CF/STB	API	50
r_w	0.35 ft		

The temperature is °R.

Water viscosity by Brill and Beggs correlation which consider only temperature effect [16]

$$\mu_w = exp(1.003 - 1.479 \times 10^{-2}T + 1.982 \times 10^{-5}T^2)$$

Where T is in °F and μ_w is in cp

Result and Discussion

A pressure build-up test was carried out on a gas condensate well that was operating under multiphase conditions. The parameters of the reservoir rock and fluid determined during well testing are listed in Table No.02.

A pressure build-up test was conducted in a gas condensate well flowing under multiphase flow. The data of pressure is given in Table No.03.

Table No.03. Pressure build-up versus time at reservoir pressure 6750 Psi.

Time Hours	Pressure Psi	Time Hours	Pressure Psi
0	1083.1	22	6161
0.167	1174.5	28	6336.5
0.333	1226.7	34	6406.1
0.5	1303.6	42	6452.5
1	1490.6	50	6487.3
2	1751.6	58	6507.6
3	2046	68	6525.5
4	2279.4	82	6556.9
6	2279.4	97	6574.3
8	3246.5	112	6587.3
12	4210	141	6601.8
16	5162		

We estimated the reservoir fluid parameters shown in Table No.04, utilizing the correlations mentioned above provided by various researcher's shut-in pressure versus time on semi-log graph paper delivered in Figure.No.05 [17].

Table 04. Calculated values of reservoir fluid properties.

q_o	100STB/D	q_g	1MMSCF/D	q_w	100STB/D
μ_o	0.1153 cp	μ_g	0.011cp	μ_w	0.1739 cp
B_o	1.420 RB/STB	B_g	0.0016 bbl /scf	B_w	1.10637 RB/STB
		R_s	528.055 scf/STB		

Effective permeability of gas condensate fluid for different phases such as effective permeability of the oil, effective permeability of gas and the effective permeability of water is calculated by putting all values in the above-given equation [6], [7] and [8] of permeability. The calculated values are given in Table No.05.

Gas condensate mobility

Effective permeability is divided by apparent fluid viscosity [18]. Mobility is a term used to describe the ease with which a fluid moves through reservoir rock.

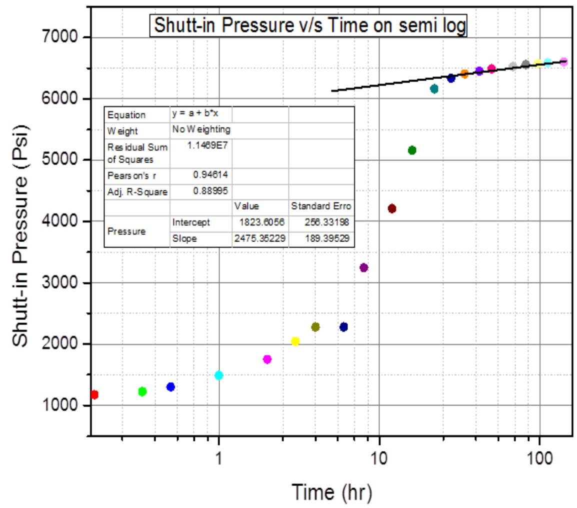

Figure 05. Semi-log graph paper of shut-in pressure vs time

The value of slope (m) calculated from the graph which is 1823 Psi/cycle.

Table 05. Calculated values effective permeability of oil, gas and water.

K_o	14.603 mD
K_g	0.148 mD
K_w	17.159 mD

The ease with which a fluid travels through reservoir rock is determined by its mobility. The gas condensate mobility is a vital function of the flow of the fluid phase. It was affected by the permeability, Viscosity, flow rate, and pressure of the flowing fluid. The values of the mobility at the different permeability are tabulated [19].

$$\lambda_t = \frac{k_o}{\mu_o} + \frac{k_g}{\mu_g} + \frac{k_w}{\mu_w}$$

$$\lambda_t = \frac{14.603}{0.1153} + \frac{0.148}{0.011} + \frac{17.159}{0.1739}$$

λ_t = 238.778 md/cp

Calculated values of the mobility of gas condensate fluid for each phase, such as oil, gas and water, are given in Table No.06.

Table No.06. Calculated values of mobility of oil, gas and water.

Mobility	mD/cp
λ_o	126.652
λ_g	13.454
λ_w	98.671

Gas condensate mobility effects on the effective permeability

The rock permeability was determined by modifying the mobility of the gas condensate fluid such as oil, gas, and water while maintaining the fluid's Viscosity constant to estimate the impacts of gas condensate mobility on the effective permeability. calculated values are given in Table No.07.

Table 07. Calculated values of oil, gas and water viscosity.

viscosity	cp
μ_o	0.1153
μ_g	0.011
μ_w	17.159

By changing the mobility of the oil, gas and water, the effective permeability of each phase of the fluid is changing; by increasing the mobility, the effective permeability is increased, the calculated mobility is given in Table No.08.

Table 08. Calculated values effective permeability and mobility of oil, gas and water.

λ_o mD/cp	k_o mD	λ_g mD/cp	k_g mD	λ_w mD/cp	k_w mD
126.652	14.603	13.454	0.148	98.671	17.159
100	11.53	100	1.1	100	17.39
105	12.106	105	1.155	105	18.259
110	12.683	110	1.21	110	19.129
115	13.259	115	1.265	115	19.998
120	13.836	120	1.32	120	20.868
130	14.989	130	1.43	130	22.607

Conclusion

Thus, well test procedure data can be used to calculate the mobility of the gas condensate reservoir, which is a fundamental property to the flow characteristic of the reservoir fluid. It was concluded that effective permeability of the reservoir fluid such as, oil 14.603 mD, gas 0.148 mD and water 17.159 mD. Using the data obtained through the correlations, the mobility (λ) of the each phase of fluid such as oil, gas and water phase is 126.652 mD/cp, 13.454 mD/cp and 98.671 mD/cp, respectively. According to the computed results, the mobility of gas condensate is a vital function of the fluid phase's flow. They are affected by the permeability, Viscosity, flow rate, and pressure of the flowing fluid.

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