

Investigation of well test behavior in gas condensate reservoir using single-phase pseudo-pressure function

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Abstract—Gas condensate reservoirs present complicated thermodynamic behavior when pressure falls below the dew point pressure, due to fluid dropout and change in the fluid composition. Condensate blockage in the near wellbore region reduces the well deliverability. Mixture composition change in the reservoir makes the interpretation of well tests in gas condensate reservoirs a serious challenge. In this study, at first the capillary number effect and Non-Darcy Flow on compositional simulation of gas condensate reservoirs were investigated and then well test analysis was carried out. The main objective of this work was to examine gas condensate well test analysis using single-phase gas pseudo-pressure and radial composite model assuming capillary number effect and Non-Darcy Flow. For this purpose some fluid samples were selected and results compared. Results indicate that estimation of reservoir properties below the dew point is in good agreement with actual input, particularly for lean fluid samples.

Keywords: Gas Condensate, Well Test, Pseudo-pressure, Non-Darcy Flow, Capillary Number, Compositional Simulation

INTRODUCTION

When reservoir temperature is between critical temperature and cricocondentherm, the reservoir is called gas condensate. Gas condensate reservoirs have gained significant importance since the 1930's. Compared with conventional oil and gas reservoirs, these reservoirs need planning, management and different hydrocarbon recovery methods due to complicated thermodynamic behavior especially when pressure falls below dew point pressure. Fig. 1 shows an example of gas condensate reservoir. At the time of discovery, usually the

fluid is a single-phase gas and with pressure falling from the well's wall to reservoir boundary, condensate formation happens. In higher pressure falling, the process is continued until in a specified pressure, the fluids are changed to gas again and gas saturation starts again. Usually, a gas condensate reservoir produces 30 to 300 barrels of condensate for one million standard feet of produced gas. Most of the known gas condensate reservoirs are in depths of 5,000 to 10,000 feet (3,000 to 8,000 Psi pressure and 200 to 400 °F temperature) [1,2].

The important point in these reservoirs is lower levels of relative permeability of condensate and its higher viscosity in comparison with gas. Because of this, condensates are being gathered in reservoirs and they are not produced and they are therefore unrecoverable. There are two factors which affect the behavior of these reservoirs: simultaneous presence of three phases in the reservoir (regarding the water) and change of original fluid composition in the reservoir. These two factors complicate the investigation of well deliverability, well testing, well completion, fluid flow in porous media etc.

One of the approved methods in investigation of well and reservoir behavior is well-test analysis. Pressure transient tests like draw-down and buildup tests are used to analyze reservoir characteristics. Using well test analysis, permeability, skin factor and wellbore storage can be calculated. The most important advantage of this method over core experiments and well logging is that the information is recorded dynamically when producing, and therefore represents a wider range of the reservoir, and hence a better and more precise behavior of the reservoir.

Well test analysis is often interpreted by analytical simulators. Radial composite model is a proper model to explain well test data of gas condensate reservoirs. In these models, by using the change of the pseudo-pressure derivative in the logarithmic scale, the existence of several regions with different permabilities around the wellbore and also the reservoir damage because of the condensate accumulation are distinguishable.

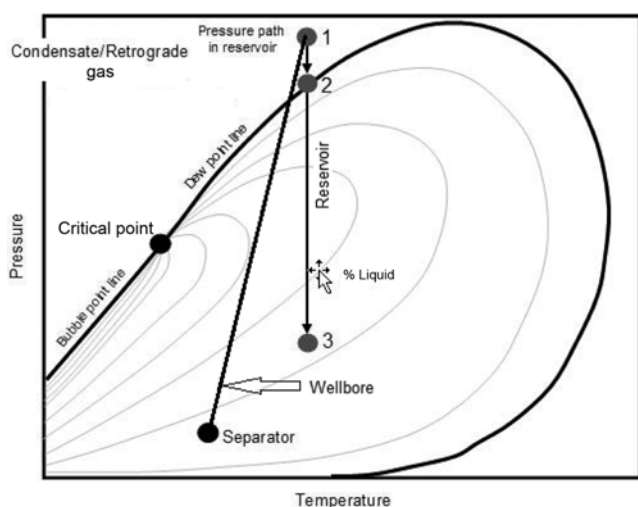


Fig. 1. Phase graph of gas reservoir.

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FLOW BEHAVIOR IN GAS CONDENSATE RESERVOIRS

With the production from gas condensate reservoir, pressure will fall in some parts of the reservoir below the dew point and condensate is produced in the reservoir. In this part theories and approaches about gas condensate flow behavior are reviewed.

O'dell and Miller developed a two region model including condensate and gas based on the concept of steady state flow supposing constant fluid composition in the time of production [3]. Fusel showed that deliverability of gas condensate well is more than what was shown by O'dell and Miller [4]. Boe et al. introduced some techniques to determine saturation in systems where pressure profile and saturation are single-valued functions of (r^2/t) . However, in gas condensate systems with non-zero skin, pressure and saturation are not in the form of $f(r^2/t)$ [5]. Jones and Reghavan showed that in gas condensate systems when the pressure is changed to steady state two-phase pseudo pressure, buildup and drawdown tests can be analyzed by classical liquid equations [6,7]. In 1995, Fevang and Whitson considered a transient region between the two mentioned regions where gas and oil are present but only gas moves and oil cannot move. They defined separate two-phase pseudo pressure for all three regions using the relationship between pressure and saturation [8]. Gringarten et al. suggested a fourth region in the nearest place to the well for these reservoirs using capillary number effect [9].

Capillary number shows the ratio of viscous forces to capillary forces. At two or three feet around the well, a high capillary number at high gas rate reduces oil saturation and increases relative gas permeability. They concluded that this new region near to the well with high capillary number increases productivity of gas condensate reservoirs significantly [9].

According to previous studies, four regions are considered in gas condensate reservoirs, which will be introduced briefly.

1. Region 1

This region exists when bottomhole pressure (P_w) is lower than the dew point pressure of external boundary of the region 2 (P^*). Condensate saturation is not adequately high in this region in order for flow to happen. The flow composition of mixture and also GOR is constant in this region; therefore, constant composition expansion test can be applied for determining the condensate saturation [10]. By condensate accumulation, the gas relative permeability will decrease, which is the most important reason for well deliverability decrease [11].

2. Region 2

This is a transition region where condensate is produced from the beginning of the region. At the outer edge of region 2, the first droplets of liquid condensate from the original gas are formed; therefore, the pressure at the outer edge of region 2 (the boundary with region 3) will be equal to the dew point pressure of the original reservoir gas. The amount of condensate formed in this region is less than the critical amount, so still gas is the only mobile phase. Size of this region for rich reservoirs is smaller than lean ones. Regarding the fluid composition change in this region, constant volume depletion test is used to measure condensate saturation [10].

3. Region 3

In this region the pressure is above the dew point pressure and

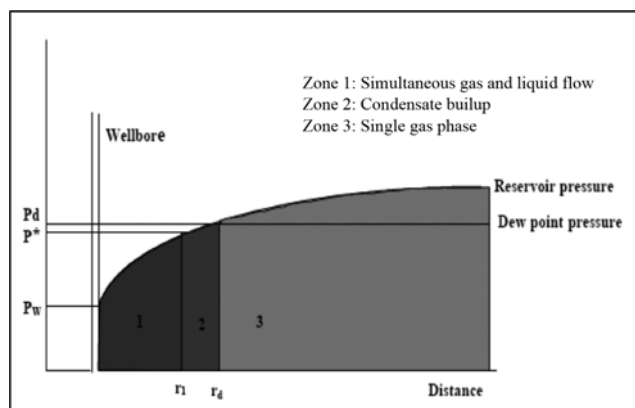


Fig. 2. Pressure gradient around condensates gas well.

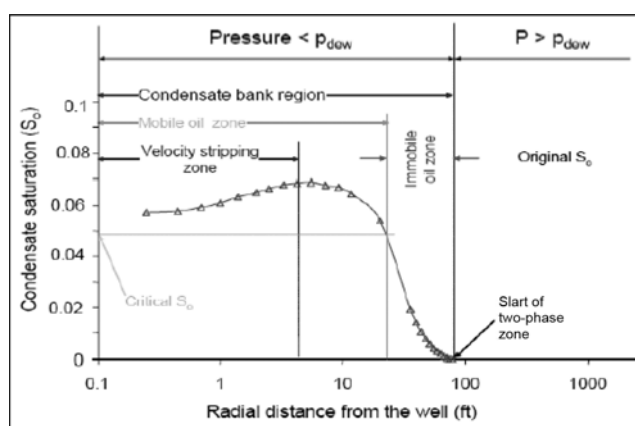


Fig. 3. Four flow region around condensates gas reservoirs.

there is only mobile single-phase gas, which is the reservoir's original gas.

4. Region 4

This region was introduced after Gringarten et al. considered effects of high velocity of gas in high flow rates near the wellbore [9]. They argued that consideration of capillary number phenomenon decreases condensate saturation and increases reservoir productivity. The only difference of this region with the first region is in amount of gas or oil saturation or their relative permeability. Oil mixture and gas GOR are constant in this region too. Fig. 2 shows pressure limit around well and Fig. 3 shows condensate saturation profile for gas condensate reservoir.

EFFECTIVE PARAMETERS ON THE BEHAVIOR OF GAS CONDENSATE RESERVOIRS

The area near the well is the most important region in calculation of well efficiency when studying the behavior of gas condensate reservoir. In pressures lower than dew point, well productivity depends on the percent of critical condensate saturation and curves of relative gas permeability which are influenced by non-Darcy flow and capillary forces.

1. Capillary Number

For a specific production rate, the highest velocity happens in a region near the wellbore, because of the small wellbore area. The

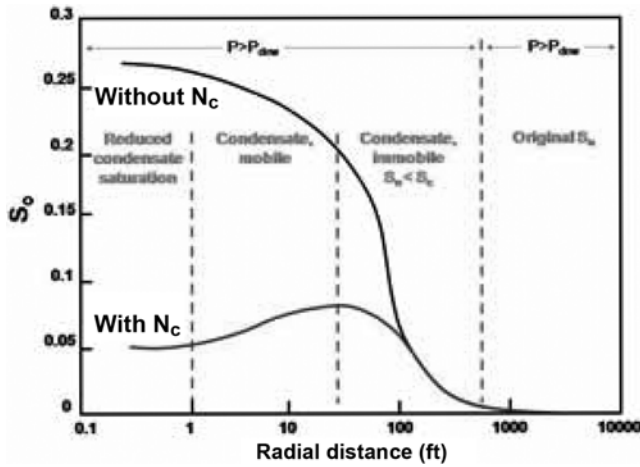


Fig. 4. Capillary number effect on condensate saturation.

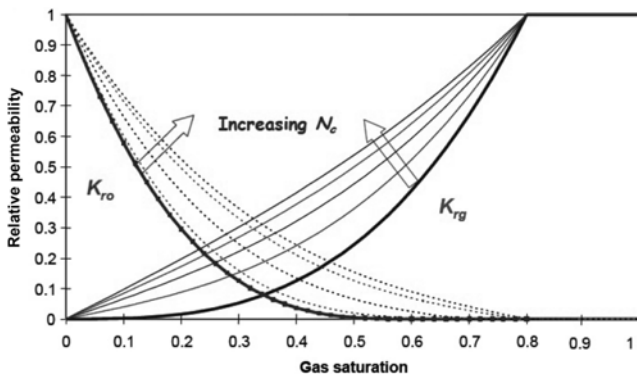


Fig. 5. Capillary number effect on relative penetrating curves.

amount of capillary number which shows the ratio of viscous forces to the capillary forces is presented in Eq. (1).

$$N_c = \frac{\mu V}{\sigma \phi} \quad (1)$$

Increase of capillary number near the wellbore has two important effects: decline of residual condensate saturation (Fig. 4) and transformation of relative permeability curves from immiscible to miscible curves (straight lines) (Fig. 5).

There are two methods for the changes of relative permeability due to capillary number in commercial simulators:

1-1. Corey Function Method

In this model relative permeability is shown by Corey function. This method is shown in Eq. (2).

$$k_{ra}(S_a, N_c) = k_{ra}^*(N_c) \left[\frac{S_a - S_{ra}(N_c)}{1 - S_{ra}(N_c)} \right]^{c(N_c)} \quad (2)$$

1-2. Interpolation Method

In this empirical method, the relative permeability curve is in near critical condition, which is often in the form of a linear function of relative permeabilities of miscible and immiscible conditions. f is weight function factor for capillary number and α and N are empirical constants. Eqs. (3) and (4) show this model.

$$k_{ra} = f(N_c)k_{ra(base)} + (1 - f(N_c))k_{ra(misc)} \quad (3)$$

$$f = \frac{1}{(\alpha N_c)^n + 1} \quad (4)$$

In this study, Corey function method for capillary number effect has been used. There are two advantages to this method. First, the influence of low interfacial tension and high velocity could be directly translated to the coefficient values. Second, Corey functions enable construction of a plausible relationship between relative permeability and the capillary number if there is no experimental data. However, the interpolation method is particularly suitable for fitting large sets of experimental data. Therefore, due to the theoretical nature of this study the Corey function is preferred.

2. Non-Darcy Flow

The Darcy equation is a linear relationship between pressure gradient and rate. This equation is not precise at high flow rates. In 1914, Forchheimer added a non-Darcy term to Darcy flow equation to explain the relationship between velocity and drawdown in porous media. This is shown in Eq. (5).

$$\frac{dp}{dl} = \frac{\mu}{k} v + \beta \rho v^2 \quad (5)$$

For single phase, the non-Darcy coefficient is constant and can be obtained through empirical equations that Li and Engler introduced in 2001 and is shown below in Eq. (6). Values a , b and c are obtained by experiment.

$$\beta = \frac{a}{k^b \phi^c} \quad (6)$$

For two-phase flow there are some limited equations like Henderson (2000), which shows the relation of non-Darcy flow coefficient (β) with fluid saturation, porosity and permeability. In Eq. (7), a , b and c are constants in the equation.

$$\beta = \frac{a}{\phi^b S_j^c (k k_r)_j^d} \quad (7)$$

WELL TEST ANALYSIS

Well test analysis is one of the methods of reservoir characterization. This technique is an invert problem solving method and well and reservoir are recognized by the use of well bottomhole pressure data versus time.

Well test analysis was started by Theis for underground waters [13]. Later, Horner suggested semi-logarithm curves [14]. Ramey developed type curves analysis [15]. Bourdet used derivative pressure curves [16]. Recently, Schroeter et al. introduced the new concept of deconvolution [17].

In single well test analysis, drawdown and buildup tests are used. The advantage of the drawdown pressure test is that it is used while producing, and the advantage of the buildup pressure test is that because the well is closed and flow rate is zero, flow rate variations are less than for the drawdown test. Usually, the buildup test is used in gas condensate reservoirs under dew point pressure, because the formation of condensate puts many variations on production flow rate in the drawdown test.

1. Well Test Analysis in Gas Reservoirs

Methods of well test analysis in oil reservoirs cannot be used for gas and gas condensate reservoirs due to high compressibility of

gas and creation of two phases in the reservoir. Many methods like pressure method and pressure-squared method have been introduced in gas reservoirs, but pseudo-pressure is the most accurate one which can be used in gas condensate systems. Pseudo-pressure function is defined as follows [19]:

$$m(p) = 2 \int_{p_o}^p \frac{p dp}{\mu Z} \quad (8)$$

Therefore, the diffusivity equation for gas becomes Eq. (9).

$$\nabla^2 m(p) = \frac{\mu c \phi \partial m(p)}{k \partial t} \quad (9)$$

2. Well Test Analysis in Gas Condensate Reservoirs

In gas condensate reservoirs above the dew point pressure, the equations are exactly like gas reservoirs, but for pressures below dew point, single or two-phase pseudo pressure methods are used.

In single-phase pseudo pressure for gas condensate reservoirs, radial composite model is used [20]. In this model, the region of condensate formation (first and second regions) and gas single phase region (third region) are considered separately and permeability can be calculated for both regions. In condensate region, the calculated permeability is the effective permeability of gas phase, and in gas single phase, it is regarded as absolute permeability. In this method the condensate is not considered as the second phase and the effect of condensate formation around the well is inserted as a skin factor around the well.

The problem with pseudo pressure is that it only considers the deviation of high compressibility of fluids in comparison with oil and neglects decline of gas permeability due to the presence of condensate around the well. So the two-phase pseudo pressure was introduced later. In the buildup test, the two-phase pseudo pressure is defined as the following:

$$m(p) = \int_{p_{ob}}^{p_{ef}} \left(\frac{\rho_g k_{rg}}{\mu_g} + \frac{\rho_o k_{ro}}{\mu_o} \right) dp \quad (10)$$

Two-phase pseudo pressure can be solved with two steady states and three-zone methods. Steady state was developed by Chopra and Carter (1986) and Jones and Raghavan (1988) [6,21]. The base of this theory is that fluid mixture in the first region is the original mixture of the reservoir and the second region is small and negligible.

Three-region method is the most comprehensive method of two-phase pseudo pressure presently. Fevang and Whitson defined two-phase pseudo pressure for each of the three regions, and finally for well deliverability used the total of these three terms [8].

The worthwhile point is that using two-phase pseudo pressure has a higher precision than single-phase pseudo pressure. In two-phase pseudo pressure “steady state” we need relative permeability curves, and in three-zone method beside relative permeability curves

we should measure the GOR and PVT properties exactly. Rous-sennac (2001) showed that even the existence of slight error in measuring these three parameters has a significant effect on calculation of two-phase pseudo pressure and leads to a big error in calculations [10]. Hence using two-phase pseudo pressure could have high uncertainty, and therefore if one cannot trust the input data, single phase gas pseudo pressure should be used.

DESCRIPTION OF SIMULATION MODEL

In this part the produced condensate around the wellbore and its effect on the behavior of well testing in gas condensate reservoirs are considered. To do this, one rich and one lean fluid were made by using the appropriate module of the commercial software. To make the reservoir model, compositional reservoir simulator was used. The effects of non-Darcy flow and capillary number were considered in this model. In the second phase, the outputs of the software (flow rate versus time) and physical characteristics of the model were used as input for the well test software.

1. Fluid Properties Model

To have a better comparison, two samples of rich and lean fluids were made. In both of them the Peng-Robinson three variable equation was used.

Molar mixture of the two fluids and their general properties are shown in Tables 1 and 2.

2. Reservoir Model

For simulation of gas condensate flow behavior, compositional simulation software is used. The following hypothesis and characteristics are regarded in reservoir simulation:

Geological complexities in the reservoir are neglected. The model is single-well and one-dimensional radial. The reservoir is assumed infinite acting. A fine-grid block system is defined in the vicinity of the wellbore to simulate condensate formation effect more precisely. The physical properties of model are assumed to be equal along the reservoir and the mechanical skin factor is zero.

The reservoir model is shown in Fig. 6. In addition, the total properties of reservoir and well are shown in Table 3 as well. The relative permeability curves for the gas-oil and water-oil are shown in the Figs. 7 and 8. If there are three phases in the reservoir, relative permeability of each phase can be counted by use of empirical correla-

Table 1. Molar composition of rich and lean fluid in the constructed model

Fluid sample/ molar composition	C1 (%)	C4 (%)	C7 (%)	C10 (%)	C14 (%)
Lean fluid	82	11	6.2	0.4	0.4
Rich fluid	75	14	10	05	0.5

Table 2. General properties of lean and rich fluids in the model

Fluid sample/ general properties	Temperature, °F	Dew point pressure, psi	Gas condensate ratio ^a , bbl/MMscf	Maximum of condensates saturation (%)
Lean fluid	200	3192.94	44.93	8.23
Rich fluid	200	3145.76	93.90	22.97

^aGas condensate ratio (CGR)

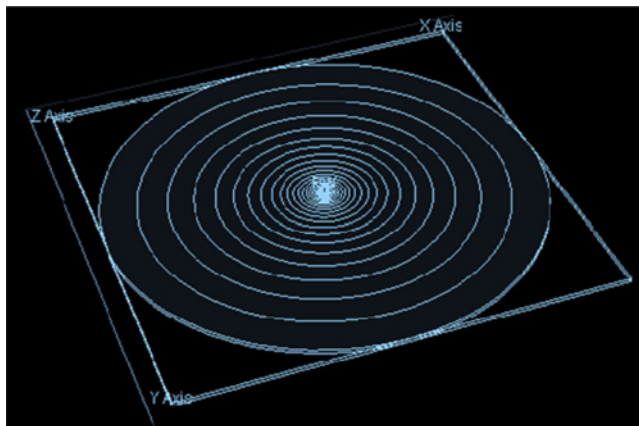


Fig. 6. A facet of single-well model at the center of radial one-dimensional reservoir model.

Table 3. Well and reservoir properties

Property	Quantity
Initial reservoir pressure, psi	3500
Reservoir temperature, F ⁰	200
Reservoir thickness, ft	50
Top of reservoir height from ground surface, ft	9000
Rock and fluid compressibility, psi ⁻¹	6.02E-6
Absolute permeability, mD	5
Porosity, %	20
Well radius, ft	0.354
Reservoir drainage radius, ft	7000
Produced flow rate, MMscf/day	5

tions such as Stone and Corey.

3. Well Test Analysis above Dew Point Pressure

This case uses lean fluid and the initial pressure of the reservoir has been considered 5,000 Psi; therefore, there will not be enough time for the formation of condensate during the production period. The capillary number and non-Darcy flow effects were considered. Other features of the model are shown in Table 3. To investigate well testing, a drawdown test was carried out for 19 days. Fig. 9 shows bottomhole pressure drop for this model. Fig. 10 shows logarithm-logarithm diagram of this model which has been drawn by well test software. This figure shows a good adaptation among inputs. Permeability is 4.86 mD and skin factor is predicted to be 0.009.

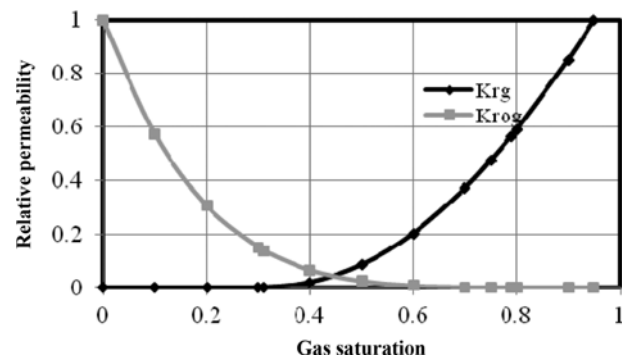


Fig. 7. Oil-gas relative permeability graph in the model.

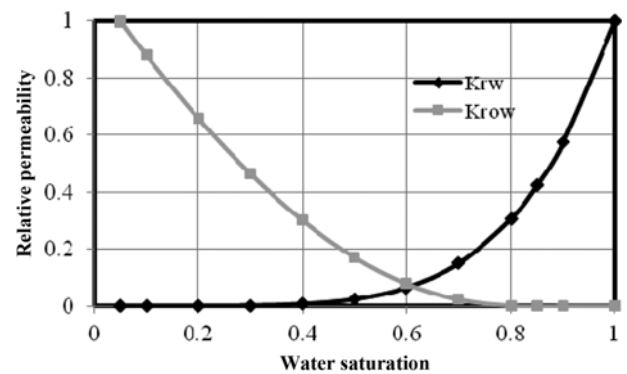


Fig. 8. Oil-water relative permeability graph in the model.

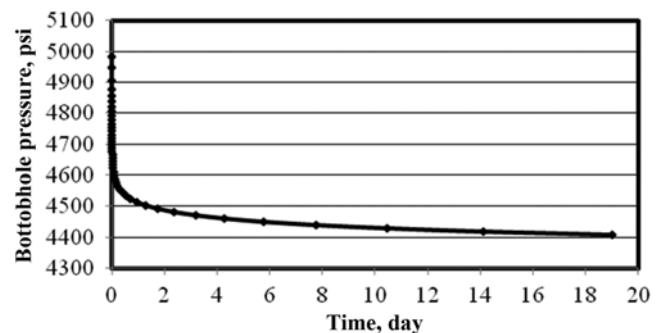
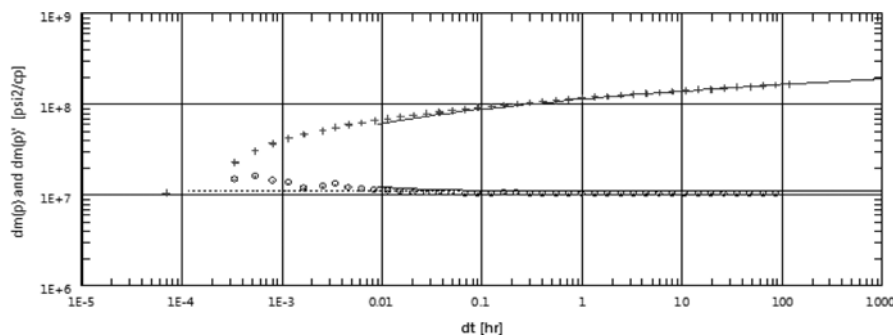


Fig. 9. Bottomhole pressure vs. time above dew point in drawdown test.

The errors of well test estimation are 2.8 percent for permeability and very small for skin, which is very good.



Well = Storage + Skin
Reservoir = Homogeneous
Boundary = Infinite

Pi = 4984.31 psia
k.h = 243 md.ft
Skin = 0.009
C = 4.85E-4 bbl/psi

Fig. 10. Logarithm-logarithm plot for lean fluid sample in drawdown test above dew point pressure.

4. Well Test Analysis below Dew Point Pressure

The permeability and the skin factor of the well test in the pressure above the dew point (single phase) are very near to the real amount; therefore, the model is credible and the difference between

real (assumed) values and values obtained by well test software in the pressure below and above the dew point are related to the condensate blockage around the wellbore. Fluid richness below the dew

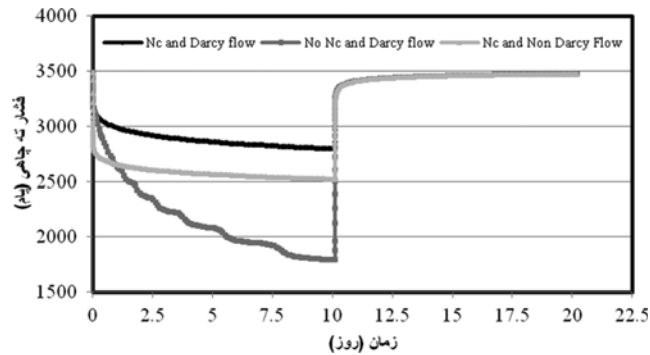


Fig. 11. History of pressure for lean fluid sample in buildup test below dew point pressure for three states.

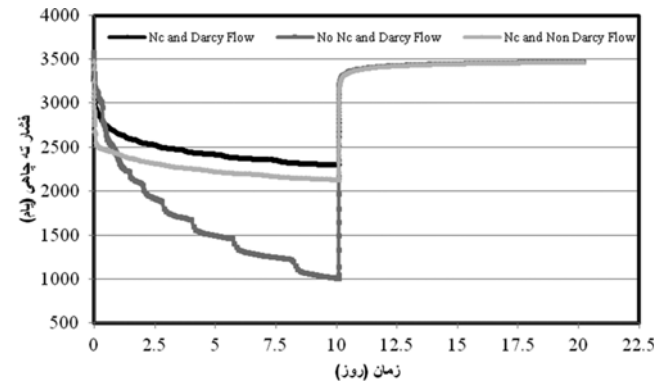


Fig. 12. History of pressure for rich fluid sample in buildup test below dew point pressure for three states.

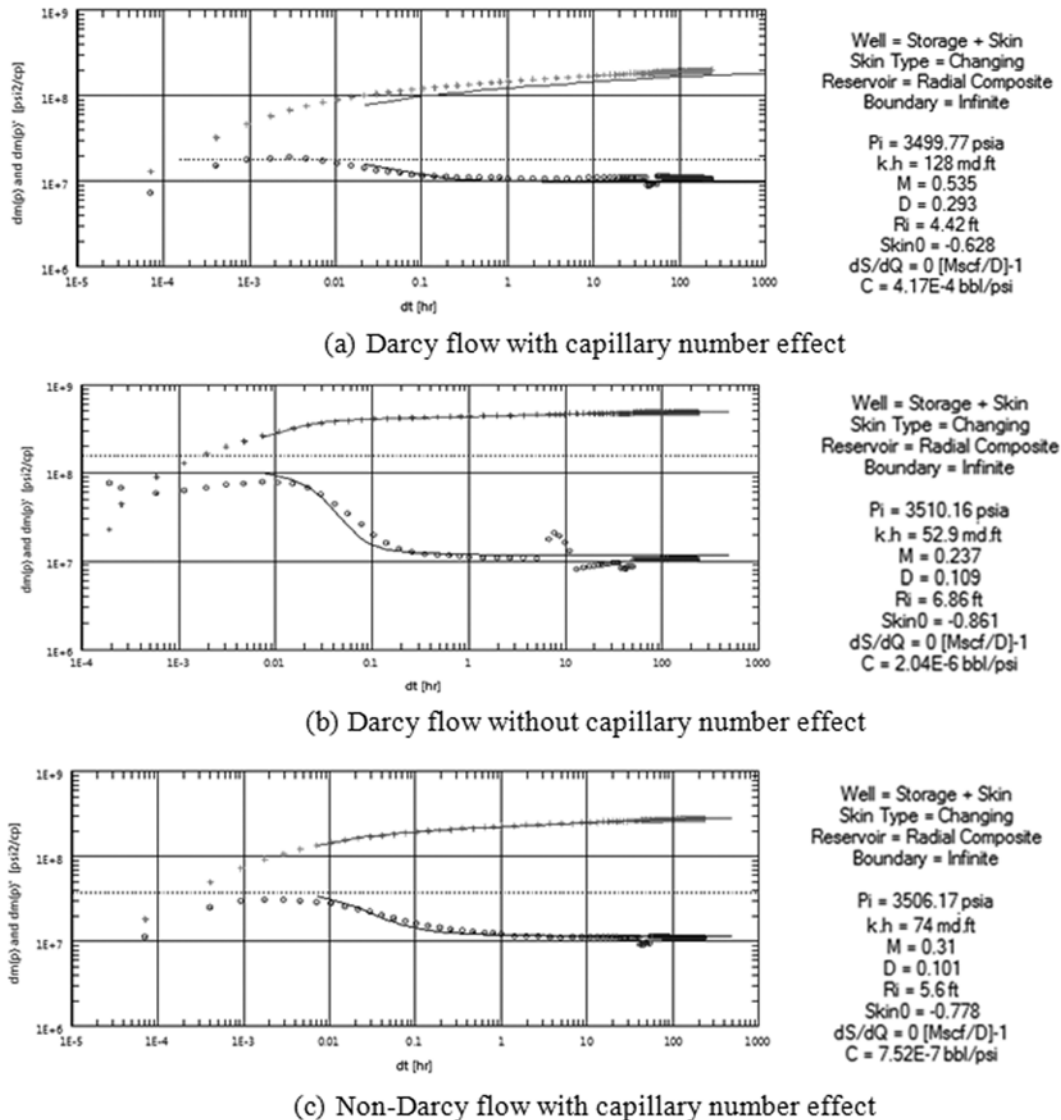


Fig. 13. Logarithm-logarithm plot for lean fluid sample in buildup test below dew point pressure for three states.

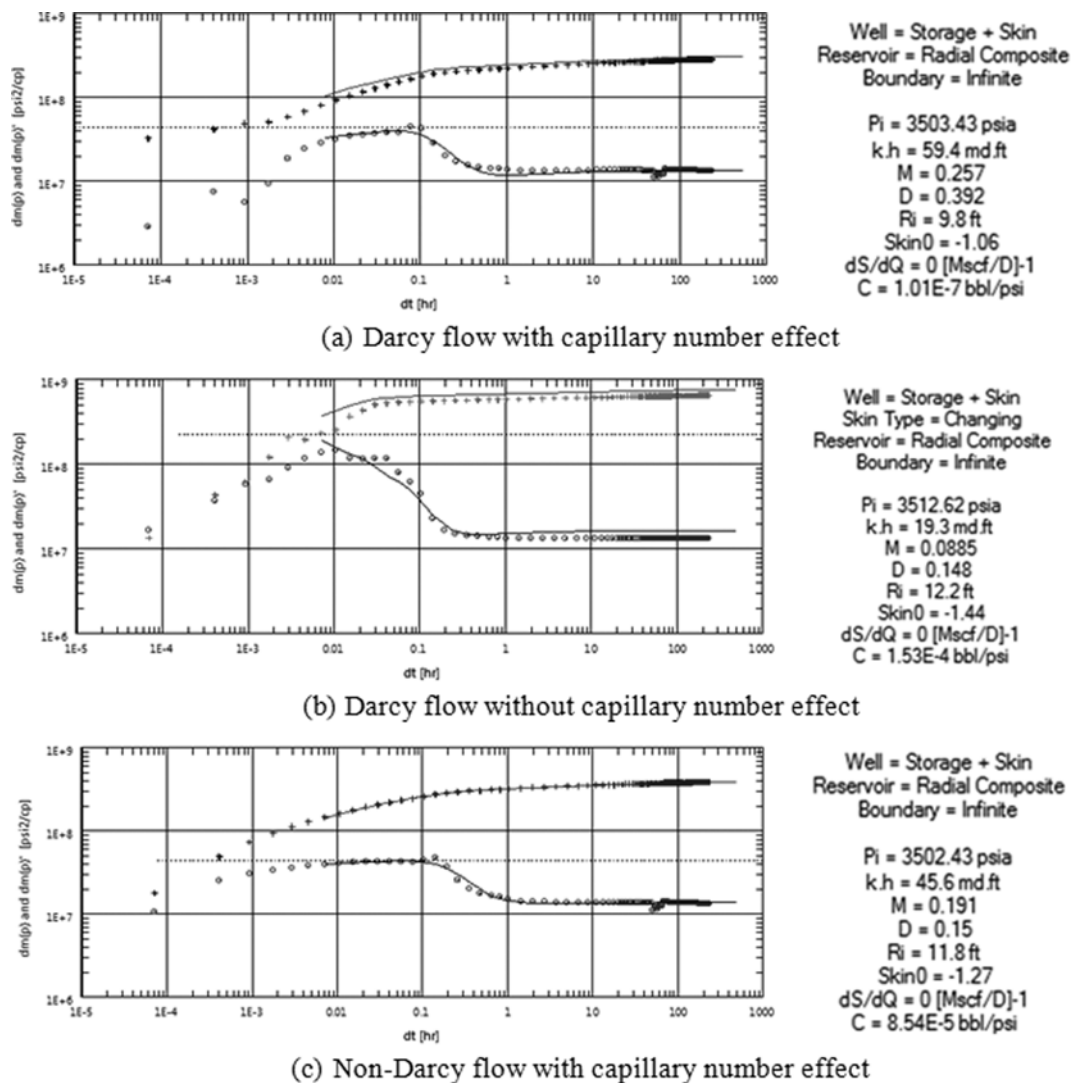


Fig. 14. Logarithm-logarithm plot for rich fluid sample in buildup test below dew point pressure for three states.

point pressure has a significant effect on condensate formation. So, well test analysis was carried out separately for lean and rich fluids. In this study, well test analysis was done in three states: Darcy flow with capillary number effect, Darcy flow without capillary number effect and non-Darcy flow with capillary number effect.

Single-phase pseudo pressure method was used for well test analysis. As it was mentioned, for cases where the input data are not reliable, single phase gas pseudo pressure is employed. Practically, because of simplicity and low cost, the single-phase pseudo pressure is preferred. To analyze well test input data in single-phase pseudo pressure method, radial composite model is used.

For lean and rich fluids, the production rate was taken as 5 million cubic feet per day and the production and shut-in (for buildup test) times were the same and assumed to be 10.11 days. Figs. 11 and 12 show the pressure drop history for lean and rich fluids in three states. Regarding these figures, the pressure drop for rich fluid is more than lean fluid, and also the effect of capillary number in the decrease of pressure drop and non-Darcy flow phenomena in the increase of pressure drop are clearly shown.

Input data are analyzed by entering the required parameters into

well test analysis software. Figs. 13 and 14 show logarithm-logarithm diagram for two fluids in three states. Predicted permeability in well test of radial composite model in Figs. 13 and 14 is related to effective permeability of gas around the wellbore. To calculate absolute permeability of a gas in a farther region from the well which only single-phase gas flows (region 3), we should divide effective permeability to its M value.

Table 4 shows predicted absolute gas permeability and initial pressure and its error for all three states of rich and lean fluids. The average absolute relative error of absolute gas permeability and initial pressure for lean fluid is 6.513% and 0.0157%, respectively, and for rich fluid are 0.176% and 8.270%, respectively. The obtained mean errors are negligible and results are acceptable for permeability.

Table 5 shows effective gas permeability in the vicinity of the well (condensate accumulation region). The radius of this region has been calculated for each of the three states explained previously for lean and rich fluids. Based on this table, the radius of condensate region for rich fluid is larger than lean one. Also capillary number effect in decrease of radius of condensate blockage region and increase of effective permeability of gas is clearly seen. The effect of

Table 4. Results of buildup test below dew point pressure for lean and rich fluid

Fluid sample	State	Property	Real value	Well test value	Error (%)
Lean fluid	Darcy flow with capillary number effect	Permeability, mD	5	4.785	4.3
		Initial reservoir pressure, psi	3500	3499.77	0.006
	Darcy flow without capillary number effect	Permeability, mD	5	4.464	10.72
		Initial reservoir pressure, psi	3500	3510.16	0.290
	non-Darcy flow with capillary number effect	Permeability, mD	5	4.774	4.52
		Initial reservoir pressure, psi	3500	3506.17	0.176
Rich fluid	Darcy flow with capillary number effect	Permeability, mD	5	4.623	7.54
		Initial reservoir pressure, psi	3500	3503.43	0.098
	Darcy flow without capillary number effect	Permeability, mD	5	4.362	12.76
		Initial reservoir pressure, psi	3500	3512.62	0.360
	non-Darcy flow with capillary number effect	Permeability, mD	5	4.775	4.50
		Initial reservoir pressure, psi	3500	3502.43	0.070

Table 5. Gas effective permeability and radius of condensates blockage region for lean and rich fluid

Fluid sample	State	Effective gas permeability in condensates blockage region, mD	Radius of condensates blockage region, ft
Lean fluid	Darcy flow with capillary number effect	2.56	4.42
	Darcy flow without capillary number effect t	1.058	6.86
	non-Darcy flow with capillary number effect t	1.48	5.6
Rich fluid	Darcy flow with capillary number effect	1.188	9.8
	Darcy flow without capillary number effect t	0.386	12.2
	non-Darcy flow with capillary number effect t	0.912	11.8

non-Darcy flow is opposite of capillary number effect.

Maximum gas effective permeability and minimum condensate radius happen for the condition when there is lean fluid and the capillary number effect and Darcy flow are considered. Also, minimum gas effective permeability and maximum condensate radius occur when there is rich fluid, Darcy flow is considered and the capillary number effect is neglected.

CONCLUSIONS

Well test behavior was studied in homogeneous gas condensate reservoirs for rich and lean fluids in different states with the effect of non-Darcy flow and capillary number below dew point pressure. Also, the effect of produced condensate on absolute permeability and initial pressure was investigated. Models for a reservoir and its fluid were made by compositional simulator and well test software was used to analyze the results. Based on performed simulation and analysis, the following conclusions are made.

1. Due to influence of capillary number, a new region (region 4) exists in the gas condensate reservoirs immediately in the vicinity of wellbore.

2. The capillary number effect and non-Darcy flow are responsible for decrease and increase of pressure drop in the gas condensate reservoirs. Usually, non-Darcy flow effect is less than capillary number effect such that the total effect of these two is positive, which makes gas effective permeability to increase and condensate saturation to decrease.

3. With employing radial composite model and single-phase pseudo-pressure in gas condensate well test analysis, acceptable results

can be obtained. These results are more accurate for lean fluid than rich fluid.

4. Well test behavior in the gas condensate reservoirs is very sensitive to the properties of the reservoir fluid behavior. Therefore, fluid sampling must be carried out very carefully.

5. For rich fluids, pressure drop and condensate saturation are higher around the wellbore and derivative plot of single-phase pseudo-pressure is in a higher place than the final state. Hence, effective gas permeability decreases and condensate blockage region radius increases.

NOMENCLATURE

C	: wellbore storage constant [bbl/psi]
D	: storativity ratio of the first region to the second one in the radial composite model
M	: mobility ratio of the first region to the second one in the radial composite model
P	: pressure [psi]
P_d	: initial fluid dew point pressure in gas condensate system [psi]
P_i	: initial pressure [psi]
P_w	: bottomhole pressure [psi]
P^*	: produced fluid dew point pressure in gas condensate system [psi]
R_i	: discontinuity radial between region 1 and 2 in the radial composite [ft]
S_a	: saturation of phase a
S_r	: residual saturation percent
h	: reservoir thickness [ft]

k	: permeability [mD]
k_r	: relative permeability [mD]
$k_{ro(base)}$: basic relative permeability diagram for immiscible state (capillary forces dominated)
$k_{ro(misc)}$: basic relative permeability diagram for miscible state (viscous forces dominated)
k_r^*	: end point of the relative permeability curve
$m(p)$: pseudo-pressure [psi ² /cp]
r	: distance from the well [ft]
s	: skin factor
t	: time [hr]
z	: gas compressibility factor
dS/dQ	: rate dependent skin factor in the gas reservoirs
ε	: core function exponent
β	: non-Darcy flow coefficient
ϕ	: porosity
σ	: interfacial tension [dyne/cm]
μ	: viscosity [cp]
ρ	: density [lb/ft ³]
v	: velocity in the porous media [ft/s]
GOR	: gas oil ratio [MMscf/bbl]
N_c	: capillary number
PVT	: pressure volume temperature
o	: subscript relating to the oil phase
g	: subscript relating to the gas phase

SI Metric Conversion Factor

bbl×1.5900	E-01=m ³
cp×1.0	E-03=Pa·s
ft×3.048	E-01=m
md×9.869233	E-04=μm ²

psi×6.894757	E+00=kPa
dyne×1.0	E-05=newton
lb/ft ³ ×1.603	E+01=kg/m ³

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