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Estimation of Gas Condensate Reservoir Behavior Using Multi Phase Pseudo Pressure Function and Well Test Analysis

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Abstract: An unusual behavior in reservoir fluids is caused in gas condensate reservoirs, when the pressure decreasesbelowthe dew point. In this condition the gas condensates start to form. Wellbore vicinity is the first point for the emergence of condensates since the maximum pressure drop happens in this region. Consequently, this procedure is propagated in other parts of reservoir as time elapses and the pressure keeps declining. Generation of gas condensatesreduces both relative gas permeability and performance of the reservoir. In the current paper, the behavior of a real gas condensates reservoir of central Iran was studied through numerical simulation and interpretation of well test data. The research comprises application of multiphase pseudo-pressure function for such reservoirs. To get this goal, the pressure data were simulated in a gas condensate reservoir for pressure draw-down and build-up states in two different conditions. In the first condition, nine days of draw-down and five days of pressure build-up were simulated with zero initial water saturation while the second condition included fourteen days of draw-down and five days of pressure build-up with an initial water saturation of 30%. Finally, the obtained parameters of pressure data were compared with primary and actual ones. The results demonstrate the acceptable applicability of pseudo-pressure function in multi-phase systems for accurately estimating reservoir parameters including total skin factor caused by near-wellbore condensation, effective permeability of phases and initial reservoir pressure.

Key words: Gas condensate · Dew point · Pressure draw-down · Pressure build-up · Pseudopressure function

INTRODUCTION

Condensate gas reservoirs are scattered worldwide, receiving considerable attention in the recent years. These reservoirs are remarkably different from other oil and gas accumulations in terms of fluid behavior and production mechanism. Phase behavior and also pressure variations of gas condensate reservoirs completely differ from that of two-phase systems. In these reservoirs, production rate is not only a function of pressure gradient but instead, it is complexly dependent to bottom-hole pressure as well. Bottom-hole pressure value determines amount and distribution of condensate accumulations in the vicinity of wellbore; this event referred as "*condensate bank phenomenon*" is followed by production decline due to reduction in relative gas permeability. Evaluation of these types of reservoir includes reserve estimation, size of well-head facilities and reservoir production mechanism, while its accuracydepends upon precise understanding of relations and behavior of two-phase flow.

Near-wellbore region exhibits retrograde phase behavior at pressures below dew-point in gas condensate reservoirs. Most known gas condensate reservoirs are single-phase at the time of exploration; however, reservoir pressure decreases isothermally as production proceeds and finally drops below dew point leading to generation of condensates. In multi-phase systems (two or three phases), high gas flow rate causes complexity of well test data analysis; thus, more novel methods such as multi-phase, pseudo-pressure function are required for achieving reservoir characteristics. Newly proposed definitions for pseudo-pressure function incorporate relative permeability of all phases. Accordingly, application of multi-phase pseudo-pressure function for interpreting well-test data in gas condensate reservoirs

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could be a precise method for studying physical gas properties and flow behavior of multi-phase system during transient pressure analysis.

In the world of reservoir engineering, well testing is one of the most applicable tools for estimating reservoir parameters and evaluation of well condition. Most of the proposed approaches for well testing are based on diffusion equation in which several assumptions simplify the problem. Single phase flow of liquid is one of these assumptions, whereas the behavior of reservoir changes to multi-phase after a period of production. Dissolved gas and gas condensate are examples of these types of reservoirs. In recent years, several researches have focused on studying the gas condensate reservoirs because of their importance [1-7]. The temperature of gas condensate reservoirs changes between critical temperature and critical condensation temperature. Generally, the hydrocarbons are completely in gas phase while the condensate starts to evolve during an isothermal process of pressure drop. This reverse behavior in gas condensate reservoir is the main reason for referring this phenomenon as "*retrograde condensation*". However, the generation of liquids will stop if the pressure reduction continues. Under these circumstances, the liquids are converted to gas. The condensates are a mixture of liquid and gas fluids whereas the liquid part is more valuable; therefore it is more desirable for petroleum companies to have liquid component at surface. In the case of condensate generation in the reservoir, the relative gas permeability would be impaired; as a result, production of gas with lower condensate content will not be feasible anymore.In this research, an overall literature review of gas condensate reservoirs is initially presented, which incorporates basic concepts, formerly proposed models, associated formulas and the principles for analysis and interpretation of welltest data in such systems. Then, the methodology used in this paper is introduced by explaining the numerical simulation and respective well test analysis and reservoir properties estimation. The results are presented and discussed in the subsequent section. Finally, the paper ends with conclusions of the research and recommendations for further studies in future concerning simulation and analysis of gas condensate reservoirs.

Theoretical Background: Condensation might occur in entire reservoir if average pressure keeps on decreasing in gas condensate reservoirs [8]. proposed a simple model for investigating behavior of such systems, in which reservoir is divided in three regions and the pseudo-pressure function is defined in terms of relative permeabilities and reservoir fluid properties:

- Region 1:Liquid (condensate) saturation in this region is above critical saturation and hence both gas and liquid phases are mobile. Production gas-oil-ratio (GOR) is constant in the first region.
- Region 2: The intermediate region is where condensates start forming. Condensate saturation is below critical value and therefore, only gas phase is mobile because condensate mobility is zero in this region.
- Region 3: This region is far away from wellbore and in fact includes all points, where reservoir pressure is higher than dew-point pressure. Single-phase gas is present in this region, being the only mobile phase.

Depending on production condition, one, two or three zones might occur. These three regions introduce pseudo-steady state flow state signifying that they represent steady state in a certain interval of time but steady state gradually changes during reservoir depletion.Pseudo-steady state assumption is held for defining relative of permeability of different phases. Ratio of oil and gas permeability is a function of reservoir fluid's thermodynamic properties as evaluated from the following formula:

$$\frac{K_{rg}}{K_{ro}}(p) = \left\langle \frac{GOR_{producing} - GOR_{solution}}{1 - GOR_{solution} \times GOR_{producing}} \right\rangle \frac{B_{gd}\mu_g}{B_o\mu_o} \qquad (1)$$

Also, [9] proposed presence of a fourth layer in wellbore vicinity. High Capillary number and low interfacial molecular tension in high flow rates results in reduction of liquid saturation and improvement of relative gas permeability. They inferred that the new region in wellbore vicinity with high capillary number contributes to remarkable enhancement of well productivity in gas condensate reservoirs.

Many pressure transient tests can be interpreted and analyzed using solution of diffusivity equation having assumed slight compressibility of reservoir fluid. When reservoir fluid is liquid, it can be considered as single-phase fluid with low and constant compressibility and fixed viscosity. The final diffusivity equation in this condition is linear and will have different solutions for varying boundary conditions.

[10] proposed pseudo-pressure function for linearization of flow equations in multi-phase reservoirs. After three years, this methodology was developed by [11]. He proposed an applied methodology for evaluating pseudo-pressure function in reservoirs with solution-gas-drive mechanism and showed that this procedure can be used for obtaining absolute reservoir permeability using the well-test interpretation methods analogous to those of oil reservoirs. Pseudo-pressure transform for multi-phase oil and gas flow is presented below:

$$m(p)_o = \int_{p_b}^{p} \frac{K_{ro}}{\mu_g B_g} dp \quad (2)$$

[12] proposed the following formula for pseudo-pressure function of gas in surface conditions and with the assumption of immobile water:

$$m(p)_o = \int_{p_b}^{p} (\frac{K_{rg}}{\mu_g B_g} + R_{so} \frac{K_{ro}}{\mu_g B_g}) dp \quad (3)$$

[13] used a new equation for multi-phase pseudo-pressure function as below:

$$m(p)_g = \int_{p_b}^{p} (\frac{K_{rg}}{\mu_g B_g} + R_{so} \frac{K_{ro}}{\mu_g B_g}) dp = \int_{p_b}^{p} (\frac{K_{eg}}{\mu_g B_g} + R_{so} \frac{K_{eo}}{\mu_g B_g}) dp \quad (4)$$

They also modified the two-phase pseudo-pressure function for 3-phase case as follows:

$$m(p)_g = \int_{p_b}^{p} (\frac{K_{eg}}{\mu_g B_g} + R_{so} \frac{K_{eo}}{\mu_g B_g}) dp + R_{sw} \frac{K_{ew}}{\mu_w B_W}) dp \quad (5)$$

[14] took advantage of a similar two-zone method for defining saturation profile in wellbore vicinity. He used a one-dimensional radial and compositional model to predict well performance in a gas condensate reservoir.

Data analysis using single-phase pseudo-pressure is a well-known method for interpreting well-test data. [15]used this methodology and identified presence of three different regions in the reservoir. They simulated different states in various time durations.

What Is Retrograde Condensate?: The term "*retrograde condensate*" is used to describe highly complicated behavior of condensate reservoirs, caused by liquid formation due to isothermal pressure decline. Though the total composition is constant, but the ratio of gas and liquid phases changes along these lines. In such systems, saturation pressure is where quality is 100% and dew-pressure line represents the points where liquid percentage is zero. Retrograde condensate zone is defined by quality lines which exhibit a maximum with respect to temperature and pressure. However, it must be noted that this temperature must lie between critical temperature and maximal temperature of phase diagram (critical condensate temperature). If initial reservoir pressure is greater than the dew-line pressure of reservoir fluid, therefore, this hydrocarbon system is initially at single-phase state (gas phase) and remains in the same state line during isothermal pressure reduction until reaching to saturation curve. When the pressure drops below dew-point, liquid phase starts being formed in the reservoir. Liquid formation continues until reaching to a maximum point. Condensate gases are also called "retrograde gases" because, unlike pure materials, more liquid is observed in them with further pressure reduction.

Methodology: Pseudo-pressure function method was used in this study to analyze well-test data of a gas condensatereservoir located in Central Iran. Despite simplicity, these methods are able to bring about useful predictions of reservoir fluid conditions.

The first step in this regard is to prepare a numerical simulation for estimating reservoir parameters. To do so, a numerical simulator was applied for generating pressure data, in which composition changes, non-linearity of gas system and concept of three-phase relative permeability have been all taken into account. In the subsequent step, the pressure data obtained from simulation are analyzed using SAPHIR software.

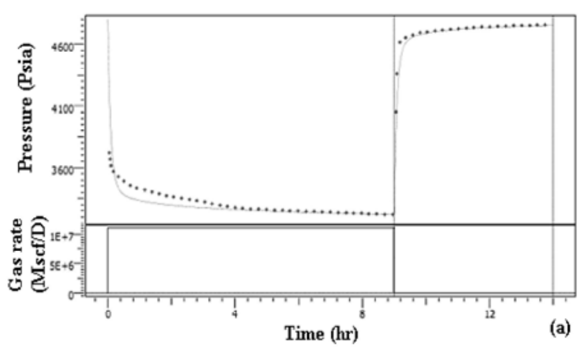
Numerical Simulation: In this paper, the understudy model is composed of 10 homogeneous layers with 41 grids. The grids have been selected in wellbore vicinity in order to investigate impact of condensates on different parameters such as relative permeability and saturation of each phase. It was also assumed that the well is completed all over the reservoir thickness due to drilling and completion not condensation bank and initial skin factorwas neglected. The reservoir fluid in this study is a lean condensate gas with maximum liquid formation of 10%. Simulation data are presented in table 1; reservoir fluid properties and composition are included in table 2.

Table 1: The reservoir characteristics and production data used in the simulation.

Initial Reservoir Pressure,Psia	4800
Reservoir Temperature, °F	350
Porosity	0/2
Formation Permeability, md	15
Formation Thickness, ft	131/2
Drainage Radius, ft	6000
Well Radius, ft	0/32808
Number of grids in “r” direction	41
Number of grids in “z” direction	8
Number of grids in “è” direction	1
Production Rate, MMSCF/D	5/2

Table 2: Composition and properties of the understudy reservoir fluid.

Component	Composition (mole fraction)	Pc (atm)	Tc (°R)	Vc (m^3/kgmole)	Molecular weight (Kg/kgmole)	Acentric factor	Parachor
CO2	0.161	72.82	304.2	0.093	44.01	0.225	49
C1	0.709	45.41	190.6	0.099	16.04	0.008	71
C2-C3	0.079	45.72	330.5	0.169	34.33	0.1191	130
C4-C6	0.026	34.9	453.8	0.298	67.13	0.2257	230
PS1	0.019	26.01	606	0.49	122.63	0.3056	327
PS2	0.003	14.87	869.6	1.058	294.67	0.7879	761



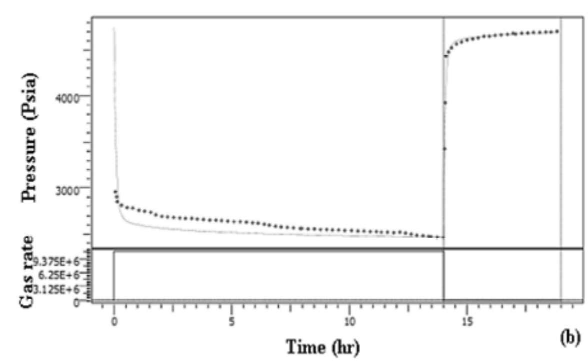


Fig. 1: Pressure and flow rate diagram in the under-study gas condensate reservoir. (a) initial water saturation is 0%, (b) initial water saturation is 30%.

Initial reservoir temperature is 335 °C and initial reservoir pressure is 4800 psia, greater than dew-point pressure, which is equal to 4408 psia.

Four different types of fluids were considered in this study: water, oil, gas and gas condensates. The respective relative permeability curves were introduced to the simulators. Also, multi-phase pseudo-pressure function was used to assess accuracy and application of this method in well-test data. Finally, the effect of flow velocity was investigated on relative permeability of multi-phase system in the simulation.

Studying a Real Gas Condensate of Central Iran: After numerical simulation, two different conditions were simulated in this study. In the first condition, the test included 9 days of drawdown and 5 days of pressure build-up. Initial water saturation was taken equal to zero in this state. The second conditionwas 14 days of drawdown and 5 days of pressure build-up. All production and reservoir data were the same as the first condition but initial water saturation which was 30% in the second scenario. In fact, only pressure build-up data are preferred for estimation of reservoir propertiesin both conditionsbecause the data achieved from draw-down test are influenced by flow rate fluctuations; this problem is specifically emphasized in gas condensate reservoirs. However, saturation and relative permeability of different phases will be presented during draw-down test for interpretation of reservoir model and overall behavior. Bottom-hole pressure curves are illustrated in Figure 1. The simulated models comprise effect of relative permeability and zero initial skin factor

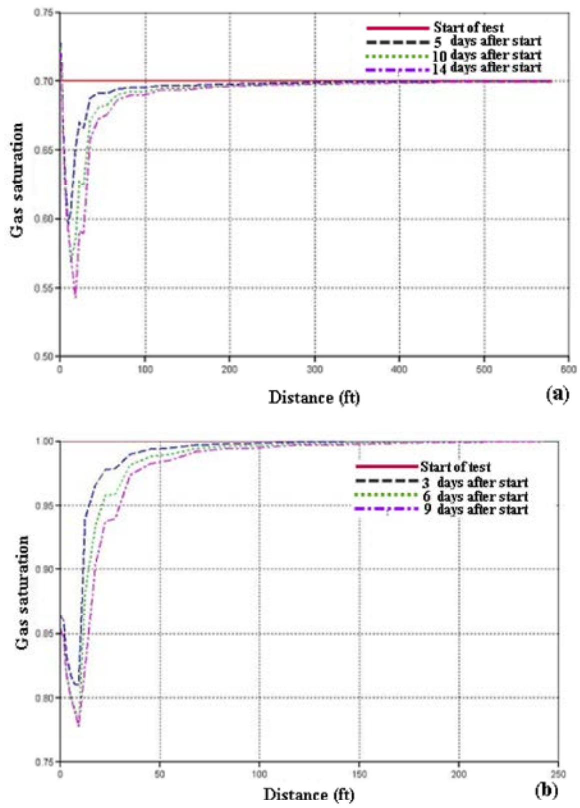


Fig. 2: Gas Saturation profile during pressure drawdown Test (a) initial water saturation is 0%, (b) initial water saturation is 30%.

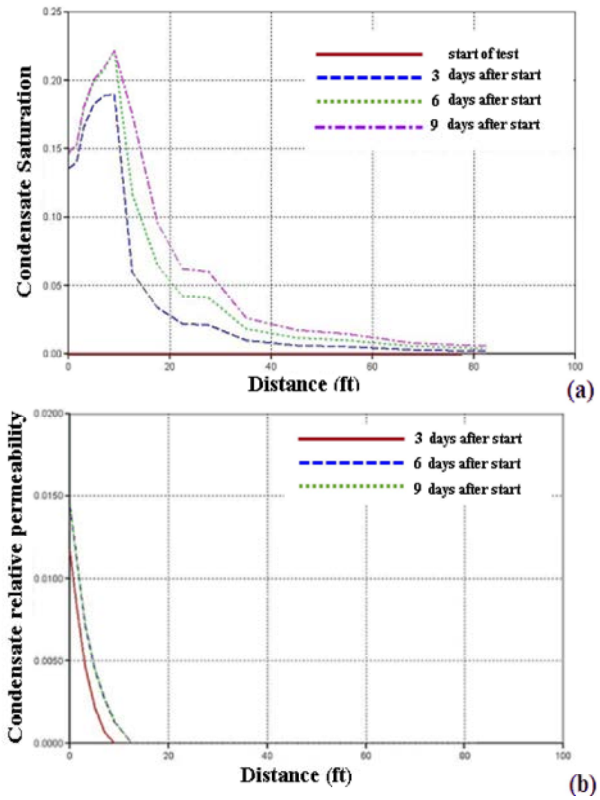


Fig. 3: (a) Condensate saturation and (b) condensate Relative Permeability Profile during Pressure draw-down test, whereas initial water saturation is 0%.

(before production). To interpret both cases, gas was chosen instead of gas condensate gas because the maximum condensation was about 1% suggesting very low condensate saturation and as a result,leading to extremely low relative permeability of this phase when pressure drops below dew-point pressure.

Figure2 demonstrate gas saturation profiles for both states (S_w=0% andS_w=30%). Saturation and relative permeability increase in the vicinity of wellbore where capillary number is high and/or relative permeability of gas would improve as flow rate increases.

Condensate saturation and relative permeability profiles are shown for both cases in Figures3and 4. Increase in gas saturation and relative permeability near wellbore is followed by reduction in saturations of condensate and water as well as their relative permeabilities. According to these profiles four distinct regions are well identified just as proposed by [9] in the literature review.

Figure 4: (a) Condensate saturation and (b) condensate Relative Permeability Profile during Pressure draw-down test, whereas initial water saturation is 30%.

Diagnostic build-up pressure diagram and pressure derivative responses can be observed in Figure 5(a). This diagram is indicative of a radial homogeneous model for the respective reservoir. Diagram in Figure 5(b) represents the semi-log plot for the first case. Semi-log plot is a straight line and, effective gas permeability, skin factor and initial reservoir pressure were calculated equal to 47 md, 9.3 and 4800 psia, respectively.Diagramin Figure5(c)demonstrates gas relative permeability profile for the first case. Absolute permeability was taken to be 45md in the simulation; hence, based on gas relative permeability curves, effective permeability in farther regions from wellbore is supposed to be equal to 45md. Therefore, a 4% error exists in estimation of effective permeability.

Total skin factor caused by condensate accumulation near wellbore is 9.3, which is a large value. The initial reservoir pressure is very close to the input initial pressure. It is worth noting that effective permeability of the condensates was evaluated to be zero. Actually, relative permeability of condensate is extremely in wellbore vicinity and nearly zero in farther zones.

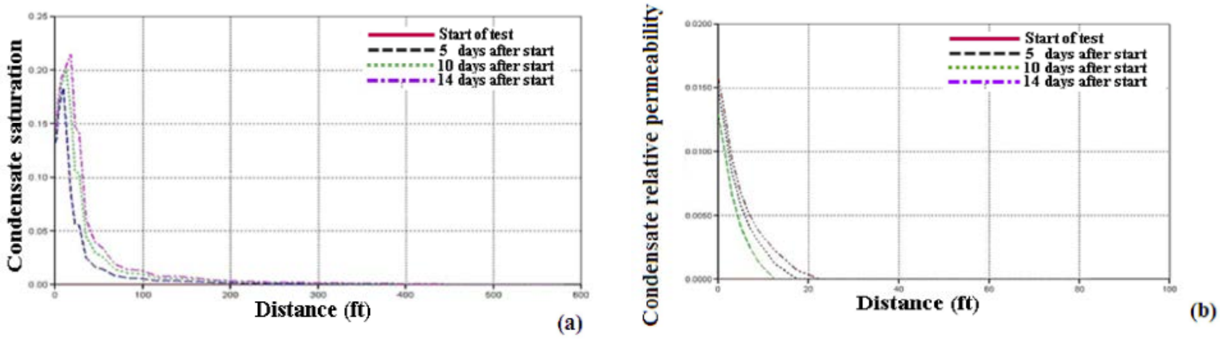


Fig. 4: (a) Condensate saturation and (b) condensate Relative Permeability Profile during Pressure draw-down test, whereas initial water saturation is 30%.

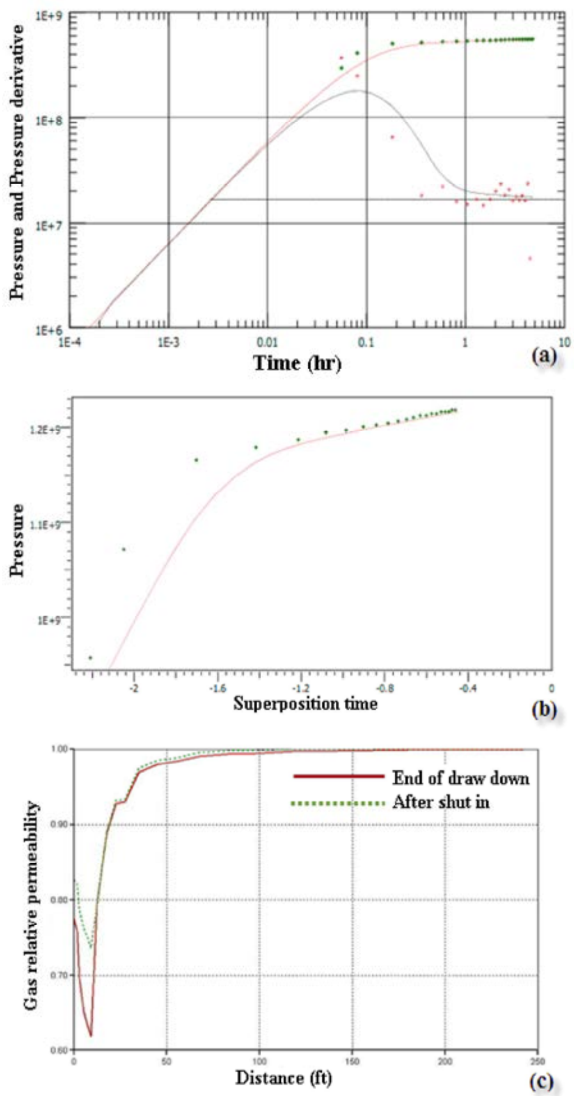


Fig. 5: (a) Log-log diagram of Pressure derivative, (b) Semi-log diagram of pressure, and (c) gas relative permeability profile during pressure build-up test, whereas initial water saturation is 0%.

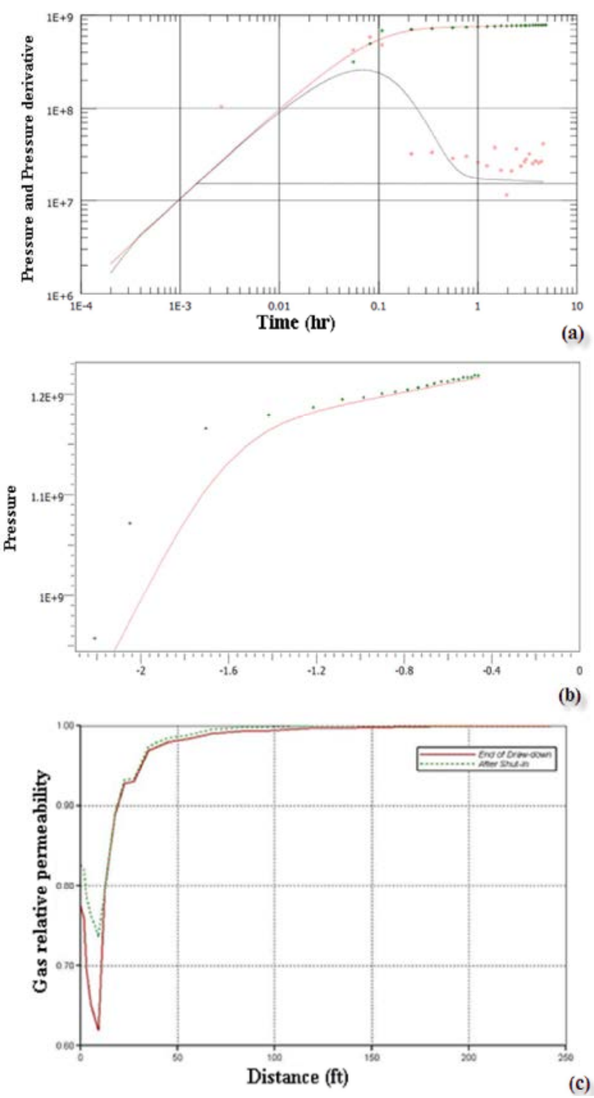


Fig. 6: (a) Log-log diagram of Pressure derivative, (b) Semi-log diagram of pressure, and (c) gas relative permeability profile during pressure build-up test, whereas initial water saturation is 30%.

Figure 6(a) illustrates the diagnostic diagram for the second case suggesting a homogeneous radial model as well. Similar to former state, semi-log plot is a straight line as manifested in Figure 6(b). The line slope is used to estimate reservoir properties as follows: effective gas permeability: 29.5md, effective water permeability: 0.8 md, skin factor: 8 and initial pressure 4903 psia. Gas relative permeability profile for the latter case was illustrated in Figure 6(c). According to these diagrams, relative permeability of gas in farther regions from wellbore, where gas saturation is 70%equals 0.65. Consequently, initial value of effective gas permeability in simulation (29.25 md) is similar to analysis results. Effective water permeability curves for the region 200 ft away from the wellbore is approximately 0.9 md, very close to the estimated value (0.8 md). The estimated initial reservoir pressure (4803 psia) is also analogous to the input value i.e. 4800 psia with a negligible error of 0.063%.

DISCUSSION

Total skin factor was evaluated equal to 8 for the second state. In this case, higher capillary numbercauses displacement of condensates in wellbore vicinity. Thus, amount of condensate formed near wellbore will decrease leading to a reduction in the value of skin factor compared to the first case. Analysis of multi-phase pseudo-pressure of pressure build-up data for both cases provides an estimate of effective gas permeability, which is very close to the initial simulation input. It can be deduced that transient pressure analysis of condensate gas reservoirs based on multi-phase pseudo-pressure function achieves a more accurate estimation of effective gas permeability with an error of 10%. The estimated total skin factor is due to the damage caused by condensate bank in wellbore vicinity, whose value is strongly dependent on capillary number. Finally, transient pressure analysis of build-up data yields a precise estimation of initial reservoir pressure with a negligible error of 0.1%. As a result, application of multi-phase pseudo-pressure function in transient pressure analysis is rather acceptable for lean condensate gas systems.

CONCLUSIONS

- Based on the results obtained in this research, multi-phase pseudo-pressure function is a reliable tool to analyze well-testing data in condensate gas reservoirs, in particular for lean condensate gas systems.
- Total skin factor would assume a remarkable value due to condensate formation in near-wellboreregion.
- Application of compositional simulation would help better understanding of condensation process and formation of condensate bank.
- According to saturation and relative permeability profiles of gas and condensate phases, 4-region model is observed in the simulation results.

Recommendations for Future Work:

- Further studies shall be conducted for investigating application of multi-phase pseudo-pressure function method for well-testing data analysis of more complex real field cases.
- Application of multi-phase pseudo-pressure function method is recommended to be assessed for rich condensate gas reservoirs.
- Effect of non-Darcy flow can be investigated in data analysis by using compositional simulation.

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