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Research Paper

Algorithm for Determining the Permeability and Compaction Properties of a Gas Condensate Reservoir based on a Binary Model

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Abstract. The paper proposes a new technique for the well-test data interpretation using two different steady-state flow tests of gas condensate well to determine the initial value of the effective reservoir permeability and the permeability change factor. The described technique has been developed on the base of the Binary filtration model of a multicomponent hydrocarbon system which considers the gas-condensate mixture as a composition of two pseudo components, taking into account the phase transformation of pseudo components and the mass exchange between the phases. The implementation of the new method requires data on well flow rates measured in two different steady-state conditions. The presented algorithm is verified on a number of examples (including real data) covering a wide range of changes in reservoir pressure and reservoir compaction factor. The results of a number of numerical experiments have confirmed the high reliability of the proposed technique.

Keywords: Gas-condensate, permeability, rocks compaction, permeability change profile, well-test data interpretation.

1. Introduction

Creating and improving a digital geological model is essential for designing and optimizing hydrocarbon field development. However, the construction of a geological model at the build-up stage of field development always takes place under conditions of lack of information obtained from direct measurements. Therefore, methods of field data interpretation in the lack of information play an important role in refining the geological model. In this sense, the development of new methods of reservoir characteristics determination with the least amount of data, such as the proposed method, is an urgent task. Determination of reservoir permeability in the early stages is also of great importance for effective design of development and selection of optimal variant of exploitation of gas-condensate reservoirs. There are three methods of permeability determination - with the use of geophysical methods, laboratory core tests and hydrodynamic interpretation of well test data. Permeability determined by geophysical methods cannot reflect the entire reservoir, as it is obtained by examining the well wall or the flow of formation fluids into the well. In addition, determining the elastic properties of reservoir rocks, including the nature of reservoir permeability changes by geophysical methods, is impossible in principle. Determination of effective permeability of formation by means of laboratory core analysis is also not reliable due to technical difficulties associated with bringing the core into formation conditions [1, 2]. Moreover, the core physically cannot represent the entire formation in its size. Consequently, permeability determined by geophysical methods and core laboratory studies can lead to large deviations [3].

Determination of permeability based on analysis of well test data is the most accurate way to determine reservoir filtration characteristics by achieving a higher REV (Representative Elementary Volume) value. The well-test data method allows determining the effective characteristics of the reservoir representing the entire reservoir and can be used in the hydrodynamic model for reservoir development design. A number of permeability determination methods currently exist [3-6], but they are not suitable for use in gas condensate wells for several reasons, chief among which is the complex thermodynamic behaviors of the gas condensate system in reservoir conditions [7], in contrast to gas and non-volatile oil. Methods based on the Black Oil model, which do not describe the processes of phase transformations during filtration of gas-condensate mixture are ineffective. Traditional hydrodynamic methods for determining reservoir filtration parameters mainly characterize the bottom-hole zone [8, 9] or do not account for compaction of reservoir rocks by reservoir pressure drops, resulting in a decrease in effective permeability [10]. Moreover, some methodologies [11, 12] based on pressure build-up curve processing require lengthy well testing and focus on determining the current permeability value rather than the initial value [13, 14]. They are complicated and not designed to determine a permeability change profile.

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It is well-known that the development of deep gas-condensate reservoirs is accompanied by changes in the filtration properties of the reservoir by the reservoir pressure drops. Numerous studies have shown that neglecting this circumstance when forecasting field development can lead to significant errors [15-17]. Therefore, determining the initial value of permeability and the profile of its change in the gas condensate reservoir by interpreting the results of well testing is an urgent task, the solution of which is the purpose of this paper.

Below we present a solution to this problem, obtained by us based on a Binary model of gas-condensate system filtration in a porous medium. The proposed solution is analytical, so it is easy to use and provides faster processing of well testing data compared to traditional methodologies, which is also important in cases of operational support and monitoring of field development. The advantages of the proposed method over the existing ones are:

- Minimal amount of information required;
- It may not be necessary to suspend well and perform well testing to collect data, as the required data are usually measured and accumulated automatically during well operation;
- The new methodology determines initial permeability, not just current permeability;
- The new methodology determines the effective permeability of the reservoir when traditional methods determine the permeability of the near-wellbore zone;
- It is possible to determine the profile (law) of the permeability change and thus to predict the permeability deterioration;
- The new methodology takes less time than the pressure build-up based methods.
- It is suitable for use in automatic data collection systems.

2. Binary Model of Gas Condensate Filtration

There are several hydrodynamic models for the filtration of a gas-condensate mixture in a porous medium. According to one of them, the gas-condensate mixture is considered as a gas-cut fluid (similar to the Black-oil model). Moreover, the model of the gas-condensate mixture used in this paper is created within the framework of the theory of filtration of multicomponent mixtures, in which the joint flow of mutually soluble fluids is considered (Composite model). The basic principle of such a model is based on the concept of motion in a porous medium of a multicomponent two-phase hydrocarbon system with phase transitions of the mixture components. A special case of this principle is a Binary model, i.e. filtration of a gas-condensate mixture is represented as the movement in a porous medium of a two-phase and two-component mixture of hydrocarbons. The components of the Binary model are gas and potential condensate, which in reservoir conditions are in liquid and gas phases, respectively. The Binary model allows to analytically solving many hydrodynamic problems. This makes it possible to use it in solving a number of inverse problems, including the interpretation methods of well-test data.

Within the framework of the Binary model, the filtration of the gas and liquid phases of the hydrocarbon system in a compacting porous medium is represented as follows [18]:

$$\frac{1}{r}\frac{\partial}{\partial r}\left[r\phi_g(p,s)\frac{\partial p}{\partial r}\right]=-\frac{\partial}{\partial t}f_g(p,s)\,, \tag{1}$$

$$\frac{1}{r}\frac{\partial}{\partial r}\left[r\phi(p,s)\frac{\partial p}{\partial r}\right]=-\frac{\partial}{\partial t}f_o(p,s)\,, \tag{2}$$

here

$$\phi_g(p,s)=\left[\frac{k_{rg}(s)\,p\beta[1-c(p)\,\overline{\gamma}(p)]}{\mu_g(p)z(p)p_{at}}+\frac{k_{ro}(s)S(p)}{\mu_o(p)B_o(p)}\right]k(p)\,,\ \phi(p,s)=\left[\frac{k_{ro}(s)}{\mu_o(p)B_o(p)}+\frac{k_{rg}(s)p\beta c(p)}{\mu_g(p)z(p)p_{at}}\right]k(p)\,,$$
$$f_o(p,s)=\left[\frac{s}{B_o(p)}+(1-s)\frac{p\,\beta\,c(p)}{z(p)p_{at}}\right]\varphi(p)\,,\ f_g(p,s)=\left[\frac{(1-s)p\,\beta\left[1-c(p)\,\overline{\gamma}(p)\right]}{z(p)p_{at}}+s\frac{S(p)}{B_o(p)}\right]\varphi(p)\,; \tag{3}$$

According to [15-17], it is known that applying the method of averaging over the coordinate r and introducing the function, $H=\int\phi(p,s)dp+\text{const}$, equations (1), (2) can be reduced to the following linear form:

$$\frac{1}{r}\frac{\partial}{\partial r}\left\{r\frac{\partial H}{\partial r}\right\}=-\Phi(t)\,. \tag{4}$$

By solution (4) under the boundary conditions $r=R_\kappa$, $H=H_k(t)$; $r=r_w$; $H=H_w(t)$ and $\partial H/\partial r|_{r=R_k}=0$ you can get a formula for calculating the well flow rate:

$$q=\frac{2\pi h(H_k-H_w)}{\ln\frac{R_\kappa}{r_w}-\frac{1}{2}}\,, \tag{5}$$

3. Algorithm for Determining the Initial Permeability and Permeability Change Factor

Formula (5) allows solving some problems of well-test data interpretation. For this purpose, the function $\phi(p,s)$ was investigated and it was found that, in practically interesting pressure drop intervals, it is approximated with high accuracy by the logarithmic function:

$$\phi=a\ln p^{-b}\,, \tag{6}$$

which can be observed by the curves in Fig. 1, where the coefficients a and b for a particular case are determined according to well-test data as described below.

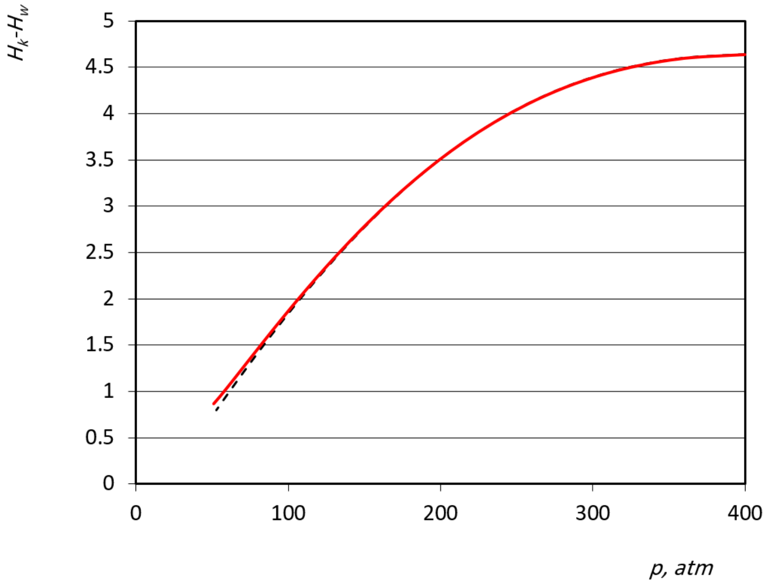

Fig. 1. The H_k-H_w curve versus formation pressure under numerical integration of the ϕ function and the logarithmic approximation: ------- numerical integration, —— logarithmic approximation.

With the consideration of the approximation (6) integrate the functions $H = \int \phi(p,s)dp + \text{const}$ within the pressure range $[p_w, p_k]$ and obtain a formula for determining pseudo-depression $H_k - H_w$ as follows:

$$H_k - H_w = a\left(\ln\frac{p_k^{p_k}}{p_w^{p_w}} - p_k + p_w\right) - b(p_k - p_w)\ , \tag{7}$$

with the consideration of which the formula for determining the flow rate of the well (5) will be:

$$q\ = M\left[a(\ln\frac{p_k^{p_k}}{p_w^{p_w}} - \Delta p) - b\Delta p\right]. \tag{8}$$

Here $M = 2\pi h\,/\,(\ln[R_\kappa / r_w] - 1/2)$, p_κ, p_w - bottom-hole and reservoir pressure, respectively.

If you have two steady-state flow well-test data (p_{w1}, p_{w2} and q_1, q_2) it is possible determination of unknown coefficients a and b by the formula (8). For this purpose let's write formula (8) for two values of bottom hole pressures (p_{w1}, p_{w2}), i.e. for two different depressions (Δp_1, Δp_2):

$$\begin{cases} q_1 = M\left[a(\ln\dfrac{p_k^{p_k}}{p_{w1}^{p_{w1}}} - \Delta p_1) - b\Delta p_1\right] \\ q_2 = M\left[a(\ln\dfrac{p_k^{p_k}}{p_{w2}^{p_{w2}}} - \Delta p_2) - b\Delta p_2\right] \end{cases} \tag{9}$$

From the system of equations (9) we find unknown coefficients a and b by following expressions:

$$a = \frac{\dfrac{q_1}{M} + b\Delta p_1}{\varepsilon_1 - \Delta p_1}\ ,\ b = \frac{q_2(\varepsilon_1 - \Delta p_1) - q_1(\varepsilon_2 - \Delta p_2)}{M(\Delta p_1\varepsilon_2 - \Delta p_2\varepsilon_1)}\ , \tag{10}$$

or taking into account b rewrite the coefficient a, as follows:

$$a = \frac{q_1\Delta p_2 - q_2\Delta p_1}{M(\Delta p_2\varepsilon_1 - \Delta p_1\varepsilon_2)} \tag{11}$$

Taking (10) and (11) into account, then (6) will be:

$$\phi = \frac{q_1\Delta p_2 - q_2\Delta p_1}{M(\Delta p_2\varepsilon_1 - \Delta p_1\varepsilon_2)}\ln(p) - \frac{q_2(\varepsilon_1 - \Delta p_1) - q_1(\varepsilon_2 - \Delta p_2)}{M(\Delta p_1\varepsilon_2 - \Delta p_2\varepsilon_1)}\ , \tag{12}$$

Here $\varepsilon_1 = \ln[p_k^{p_k} / p_{w1}^{p_{w1}}]$, $\varepsilon_2 = \ln[p_k^{p_k} / p_{w2}^{p_{w2}}]$. Taking into account (3), the coefficients a and b from (10) in expression (12) we write:

$$k(p)k_{rg}(s) = \frac{\dfrac{q_1\Delta p_2 - q_2\Delta p_1}{M(\Delta p_2\varepsilon_1 - \Delta p_1\varepsilon_2)}\ln(p) - \dfrac{q_2(\varepsilon_1 - \Delta p_1) - q_1(\varepsilon_2 - \Delta p_2)}{M(\Delta p_1\varepsilon_2 - \Delta p_2\varepsilon_1)}}{\bar{\phi}} \tag{13}$$

Here formula $\bar{\phi}$ for gas condensate system from (3) is:

$$\bar{\phi} = \frac{\phi_g}{k(p)k_{rg}(s)} = \frac{p\beta[1 - c(p)\bar{\gamma}(p)]}{\mu_g(p)z(p)p_{at}} + \frac{S(p)}{\psi\mu_o(p)B_o(p)}, \tag{14}$$

by the consideration of which, (13) rewrite as:

$$k(p)k_{rg}(s) = \frac{\dfrac{q_1\Delta p_2 - q_2\Delta p_1}{M(\Delta p_2\varepsilon_1 - \Delta p_1\varepsilon_2)}\ln(p) - \dfrac{q_2(\varepsilon_1 - \Delta p_1) - q_1(\varepsilon_2 - \Delta p_2)}{M(\Delta p_1\varepsilon_2 - \Delta p_2\varepsilon_1)}}{\dfrac{p\beta[1 - c(p)\bar{\gamma}(p)]}{\mu_g(p)z(p)p_{at}} + \dfrac{S(p)}{\psi\mu_o(p)B_o(p)}} \tag{15}$$

Here $\psi = k_{rg} / k_{ro}$. ψ can be determined according to the formula [5]:

$$\psi = \frac{[G - S(p)]zp_{at}}{\bar{\mu}(p)B_o(p)p\beta[1 - c(p)\bar{\gamma} - c(p)G]},$$

Here $\bar{\mu}(p)$ is the viscosities ratio of the liquid and gas phases; G is the gas condensate factor, known from the well testing.

If we plot a curve of dependence of kk_{rg} on pressure p according to the results obtained from (15) and continue this line until the intersection of the vertical at $p = p_0$, we obtain the initial permeability value, since, $k_{rg} = 1$ at the initial pressure. However, this is an inaccurate approach and requires many points, i.e. it is necessary to get data at several reservoir pressures, which is not always possible. In order to eliminate this difficulty, we have investigated the dependence $-\ln(kk_{rg})$ on p and found that it has been a line close to a straight line (see below for more details). This fact allows us to determine the initial permeability, having data on flow rates, measured only on two steady-state flow well conditions at two different reservoir pressures.

Thus, k_0 is determined by continuing the straight line connecting the points $[-\ln(kk_{rg})_1, p_1]$ and $[-\ln(kk_{rg})_2, p_2]$ until the intersection the vertical $p = p_0$, where $-\ln(kk_{rg})$ has the value $c = -\ln k_0$, by the expression $k_0 = e^{-c}$.

To make possible computer implementation of the methodology, it is more expedient to approximate this dependence by a linear binomial with two unknown coefficients

$$-\ln(kk_{rg}) = \alpha p + \beta, \tag{16}$$

where the coefficients α and β are determined by the same data corresponding to two reservoir pressures p_1 and p_2 :

$$\alpha = \frac{[\ln(kk_{rg})_2 - \ln(kk_{rg})_1]}{p_1 - p_2}, \ \beta = -\ln(kk_{rg})_1 - \alpha p_1 \text{ , where 1, 2 - measurement number} \tag{17}$$

However, if there is more data for greater accuracy, the coefficients α and β can be calculated by the least-squares method [19] using the following expressions:

$$\alpha = \frac{\sum_{i=1}^{n}\left[-\ln(kk_r)|_i\right] \cdot \sum_{i=1}^{n} p_i^2 - \sum_{i=1}^{n}\left[-l(kk_r)|_i \cdot p_i\right] \cdot \sum_{i=1}^{n} p_i}{n \cdot \sum_{i=1}^{n} p_i^2 - \left(\sum_{i=1}^{n} p_i\right)^2},$$

$$\beta = \frac{n \cdot \sum_{i=1}^{n}\left[-\ln(kk_r)|_i \cdot p_i\right] - \sum_{i=1}^{n}\left[-\ln(kk_r)_i\right] \cdot \sum_{i=1}^{n} p_i}{n \cdot \sum_{i=1}^{n} p_i^2 - \left(\sum_{i=1}^{n} p_i\right)^2}, \tag{18}$$

where i, n are the number and quantity of measurements, respectively. Finally, according to (16), using the values α and β found from (17) or (18), is determined at $p = p_0$:

$$k_0 = e^{-(\alpha p_0 + \beta)}, \tag{19}$$

For clarity, below is a step-by-step algorithm for implementing the above methodology to determine the initial reservoir permeability according to the well-test data in two steady-state flow conditions:

1. Having data on well flow rates q_1 , q_2 at two different bottom-hole pressures p_{w1}, p_{w2} (or depressions $\Delta p_1, \Delta p_2$) and G, kk_{rg} is calculated according to (16) for two reservoir pressures p_1 and p_2 ;
2. Using the numerical values kk_{rg} for various reservoir pressures, the coefficients α and β of the approximating function $-\ln(kk_{rg}) = \alpha p + \beta$ are determined by (18);
3. The numerical value $-\ln(kk_{rg})$ is calculated according to (16) at the initial pressure p_0 ;
4. The value k_0 is calculated by the expression (19) at p_0 .

Now consider how to determine the nature of the permeability change. Let us suppose that the reservoir undergoes elastic deformation, therefore, obeys the exponential law [2]:

$$k = k_0 \exp[\beta_k(p - p_0)] \tag{20}$$

For two sufficiently close values p_1, p_2 of reservoir pressure, we rewrite (20) by multiplying it's both sides by k_{rg} :

$$k_1^* = k_0 k_{rg} \exp[\beta_k(p_1 - p_0)],$$

$$k_2^* = k_0 k_{rg} \exp[\beta_k(p_2 - p_0)],$$

Table 1. Changes in reservoir pressure over time by variants. The selected data is used as well-test data.

t, years	p, atm		
	Incompressible formation	β_k = 0.005 1/atm	β_k = 0.01 1/atm
0.00	400.0	400.0	400.0
0.56	363.5	371.8	377.2
1.11	331.7	345.3	354.8
1.67	303.2	320.2	332.9
2.22	277.3	296.4	311.4
2.78	253.3	273.5	290.2
3.33	230.9	251.6	269.3
3.89	209.6	230.4	248.7
4.44	189.3	209.7	228.2
5.00	169.7	189.4	207.8
5.56	150.6	169.3	187.3
6.11	131.9	149.4	166.7
6.67	113.5	129.5	145.8
7.22	95.1	109.5	124.4
7.78	76.7	89.1	102.3
8.33	58.2	68.2	79.2
8.89	39.3	46.6	54.8
9.44		23.9	28.6

Table 2. Step-by-step calculations and results.

Variants	*p, atm*	*p_s, atm*	$\bar{\varphi}$	a	b	φ	kk_{rg}	$-\ln(kk_{rg})$	α	β	$-\ln(kk_{rg}) = \alpha p+\beta$	*Nominal k_0, $10^{-12}m^2$*	*Deviation, %*	*Calc. β_k, atm^{-1}*	*Deviation, %*
β_k=0.01atm^{-1}	383	373 / 363	1.16225E+12	0.3257	1.8397	0.0977	8.40696E-14	2.47611	-0.0100	6.3213	2.4761				
	360	350 / 340	1.16027E+12	0.2481	1.3830	0.0774	6.67358E-14	2.70701			2.7070				
	400										2.3054	**0.0997**	**0.28**	**0.0100**	**0.04**
β_k=0.005atm^{-1}	383	373 / 363	1.16223E+12	0.1860	0.9995	0.1067	9.17701E-14	2.38847	-0.0050	4.3161	2.3885				
	360	350 / 340	1.16028E+12	0.1626	0.8620	0.0948	8.17388E-14	2.50423			2.5042				
	400										2.3029	**0.0999**	**0.03**	**0.0050**	**0.66**
β_k=0	370	360 / 350	1.16175E+12	0.0083	-0.0673	0.1162	9.99918E-14	2.30267	0.0000	2.3156	2.3027				
	340	330 / 320	1.15420E+12	0.0187	-0.0060	0.1153	9.98865E-14	2.30372			2.3037				
	400										2.3016	**0.1001**	**0.10**	**-**	**-**

Table 3. "Well-test" data at different reservoir pressures and depressions for reservoirs of different permeability change factor.

β_k, 1/atm	*Reservoir pressure p, atm*	*Bottomhole pressure p_s, atm*	*q, m^3/day*	G
0.01	383	373	13.5	5628
		363	25.7	
	360	350	10.7	5788
		340	20.3	
0.005	383	373	15.0	5628
		363	29.3	
	360	350	13.3	5788
		340	26.0	
0.00	370	360	16.7	5713
		350	33.4	
	340	330	16.6	5960
		320	33.1	

from which, after some transformations, we obtain the following simple expression to determine β_k:

$$\beta_k = \frac{\ln\frac{k_2^*}{k_1^*}}{p_2 - p_1}, \tag{21}$$

where k_1^*, k_2^* - are the values kk_{rg} already known to us at reservoir pressures p_1, p_2, respectively.

4. Methodology Verification

All the preconditions noted above have been confirmed by the results of computer simulation of a hypothetical reservoir depletion process, using the example of the PVT data of the VII horizon of the Bulla-Deniz gas condensate field (Azerbaijan Rep.). In this case, the process is simulated for three cases that differ in values of β_k: $\beta_k = 0.005 atm^{-1}$, $\beta_k = 0.01 atm^{-1}$ and $\beta_k = 0$ (i.e., incompressible reservoir) using the following initial data:

Initial reservoir pressure $p_0 = 400$ *atm*;
Actual initial permeability $k_0 = 0.1\ 10^{-12} m^2$;
Reservoir thickness h=20m;
The well-drainage zone radius and well radius R_k, $r_w = 1000$ and 0.1m, respectively;
Initial porosity $\phi_0 = 0.2$.

Figure 2 shows the dynamics of changes in reservoir pressure in the considered variants. Marked points on the curves are selected as the well-test data. These points on the curve are specially selected at the end of the process, since they correspond to the worst development period in terms of approximation accuracy. These data are presented in numerical form in Table 1, where the values highlighted in red correspond to the marked points on the curves. In order to demonstrate the reasonableness of the proposed approach, the values $-\ln(kk_{rg})$ for the selected pressures are calculated for now using formula (3) based on the known data from the model. The obtained results for the variants are shown on the graph and they are of satisfactory accuracy, and in cases of compacting reservoirs they are even perfectly approximated by straight lines. This is conspicuously seen in Fig. 3. It is also seen that all approximating lines intersect the vertical p=400*atm* at almost the same point. That is, for variants with the same initial permeability, differing in the permeability change factors:

$$\text{at } \beta_k = 0.01 atm^{-1}\text{: } -\ln(k_1 k_{rg}) = y1 = -0.01p + 6.3162$$

$$\text{at } \beta_k = 0.05 atm^{-1}\text{: } -\ln(k_2 k_{rg}) = y2 = -0.005p + 4.2894$$

$$\text{at } \beta_k = 0 : -\ln(k_3 k_{rg}) = y3 = -0.00002p + 2.2918$$

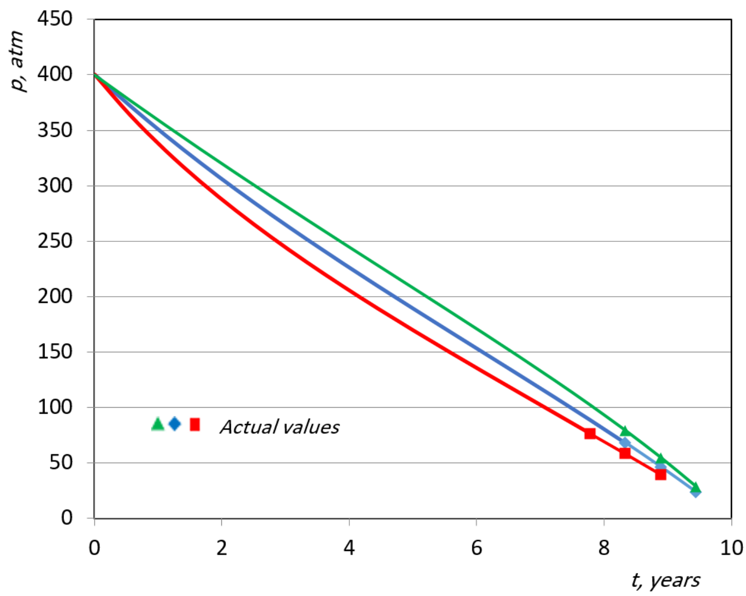

Fig. 2. Curves of changes in reservoir pressure in various variants
(green - β_k = 0.01 atm^{-1}, blue - β_k = 0.005 atm^{-1}, red - non-deformable reservoir). The marked points on the curves is well-test data.

Table 4. Well-test data at low reservoir pressures.

Actual β_k, atm^{-1}	Reservoir pressure p, atm	Bottomhole pressure p_w, atm	q, m^3/day	G
0.01	90	80	0.30	16047
		70	0.54	
	82	72	0.25	16536
		62	0.46	

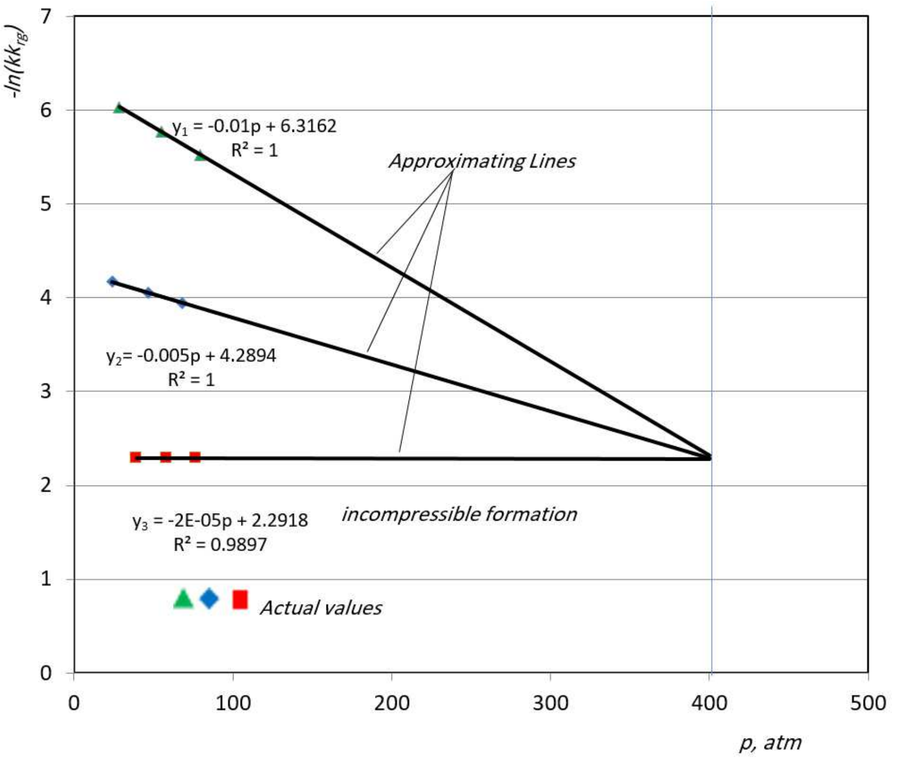

Fig. 3. Actual values of $-\ln(kk_{rg})$ and approximation straight lines.
Green - $\beta_k = 0.01\ atm^{-1}$, blue - $\beta_k = 0.005\ atm^{-1}$, red - incompressible formation.

Since, at p = 400 atm, $k_{rg} = 1$ and $k_1 = k_2 = k_3 = k_0$ then, for each variants we write:

$$-\ln(k_0) = \text{-0.01} \cdot 400\text{p} + 6.3162 = 2.3162\text{ , hence } k_0 = \exp(\text{-2.3162}) = 0.09864774$$

$$-\ln(k_0) = \text{-0.005} \cdot 400 + 4.2894 = 2.2894\text{ , hence } k_0 = \exp(\text{-2.2894}) = 0.10132724$$

$$-\ln(k_0) = \text{-0.00002} \cdot 400 + 2.2918 = 2.2838\text{ , hence } k_0 = \exp(\text{-2.2838}) = 0.10189626,$$

Here k_1,k_2,k_3 are current permeability of the corresponding variants. It is seen that in all three variants, the results are very close to the actual value of the initial permeability, which confirms the reliability of the our approach. Further, the methodology for the same variants was verified on the basis of the "well-test data", in the role of which were the flow rates corresponding to bottomhole pressures p_{s1}, p_{s2}, known from the results of simulation the depletion process. These data are shown in Table 3. Recall that we are considering three reservoir variants that differ in permeability changes (the first column in the table). For each variant, we have flow rates and gas condensate factors (columns 4 and 5) "measured" at two steady-stay flow well conditions at different dates (i.e. reservoir pressures).

Based on these data, using (15), kk_{rg} values were calculated and, therefore, $-\ln(kk_{rg})$ for two different bottom-hole pressures at two reservoir pressures according to the variants. Straight lines are drawn connecting these two points in each variant and, using (17), the coefficients α and β of the approximating binomial (16) are calculated, from which the values $-\ln(kk_{rg})$ were determined at a pressure of 400 atm and finally, the values k_0 are calculated according to (19) for all variants. For clarity, the results are presented step by step in Table 2. As can be seen from the data of the fourth column on the right, the calculated values of the initial permeability in all cases are close to the actual permeability. As can be seen from the data of the fourth column on the right, the calculated values of the initial permeability in all cases are close to the actual permeability. It is also seen from the data of the next column, the deviation of the calculated values of the initial permeability from the actual does not reach one percent in all variants. The second column on the right shows the values of β_k calculated by (21) for compressible formations. It can be seen that this parameter also quite well coincides with its actual values.

The above example is based on a well-test data, when the reservoir pressure is still quite high. It is interesting, but how can the proposed technique show itself at low reservoir pressures? To study this, it was verified on data "measured" at a late stage of development. These data are presented in Table 4.

The calculated values of the initial permeability and the permeability change factor obtained on the basis of the above data (Table 4), were also sufficiently close to their actual values. Although in this case, the relative deviations of these parameters increase slightly, but do not exceed 2.3 and 4.9 percent, respectively. Thus, the results of the verification confirm the validity and high reliability of the proposed technique, which allows determining the initial permeability and the permeability change factor in gas-condensate reservoir according to well-test data in two different steady-state flow conditions.

5. Conclusion

In the paper, on the basis of a Binary filtration model of a gas condensate system, a method was developed for determining the filtration and rheological characteristics of a reservoir formation from well-test data interpretation. The developed method required data measured in two different steady-state conditions. It was presented an algorithm for application of the obtained solution, which was verified on a number of examples (including real data) covering a wide range of changes in reservoir pressure and degree elasticity of reservoir rocks. The above approach had a number of advantages over similar techniques. The proposed technique made it possible to determine a set of parameters characterizing the filtration properties of a gas-condensate reservoir with a limited amount of data. Its implementation required information on well flow rates for two values of bottom-hole pressures and thermodynamic data of the hydrocarbon system in reservoir conditions. In contrast to similar methods, the proposed approach was based on the idea of linear approximation. This made it possible to minimize the input data (the number of measurements) and at the same time increased the reliability of interpretation, eliminating the factor of subjectivity. The proposed method was simple and reliable, as evidenced by the above verification results. It is easy to apply on the computer, which is important when automating the interpretation well-test data. Computer studies carried out in a wide range of changes in reservoir and bottom-hole pressures, initial permeability and permeability change factor have confirmed its stability and reliability.

Author Contributions

All authors contributed equally to the paper. The manuscript was written through the contribution of all authors. All authors discussed the results, reviewed, and approved the final version of the manuscript.

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Conflict of Interest

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Data Availability Statements

The datasets generated and/or analyzed during the current study are available from the corresponding author on reasonable request.

Nomenclature

Parameters with the “o” and “g” indexes correspond to a liquid and gas phase, respectively

k	Formation effective permeability, $10^{-12}m^2$
k_0	Initial effective permeability, $10^{-12}m^2$
$k_{ro}(s), k_{rg}(s)$	Relative phase permeability for liquid and gas phases, respectively, dimensionless
ϕ	Current formation porosity, dimensionless
ϕ_0	Initial formation porosity, dimensionless
a_m	Rock compressibility factor, $1/atm$
s	Pore saturation with a liquid phase, dimensionless
z, β	Gas compressibility factor and temperature correction for the gas phase, dimensionless
c	Content of potentially liquid hydrocarbons in the gas phase, m^3/m^3
μ_o, μ_g	The viscosities of the liquid and gas phases, respectively, $atm.s$
B_o	Volume factor of the liquid phase, dimensionless
S	Solubility of gas in liquid phase, m^3/m^3
p	Reservoir pressure, atm

p_{at}	Atmospheric pressure, atm
p_0	Initial reservoir pressure, atm
p_w	Bottom-hole pressure, atm
p_e	Pressure at the external boundary, atm
$\bar{\gamma} = \gamma_o(p) / \gamma_g(p)$	Ratio of the specific gravities of the liquid and gas phases at reservoir pressure, dimensionless
r	Radial coordinate
R_k	Well drainage area radius, m
r_w	Wellbore radius, m
ν	Velocity, m/s
Ω	Porous volume, m^3
Ω_0	Initial porous volume, m^3
ρ	Density of liquid phase, kg/m^3
h	Formation thickness, m
t	Time, s

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