Frontiers in Computing and Intelligent Systems
ISSN: 2832-6024 | Vol. 4, No. 3, 2023

Well Testing Analysis Method and Practice for Low Permeability Gas Reservoirs

Huohai Yang, Qingrong Liao

Petroleum Engineering School, Southwest Petroleum University, Chengdu, China

Abstract: With the gradual maturity of well testing interpretation theory, some scholars have conducted research on vertical well testing models, horizontal well testing models, and inclined well testing models for fractured and vuggy reservoirs, and plotted typical well testing curves. However, during the drilling process, the wellbore is usually connected to both the fractures and the reservoir matrix, resulting in a dual permeability situation where the fractures and matrix simultaneously supply fluid to the wellbore. Based on this, some scholars have established a horizontal well dual hole dual permeability testing model, a vertical well three hole dual permeability testing model, and a horizontal well three hole dual permeability testing model, making the results of well testing interpretation more reasonable and reliable. For the well testing analysis of inclined wells in fractured and vuggy reservoirs, the existing inclined well models only consider the three hole single permeability situation where the fractures are connected to the wellbore. There is little research on the three hole dual permeability well testing model where the inclined well matrix and fractures supply the wellbore simultaneously. Therefore, based on previous research, this article establishes and solves a well testing model for inclined wells with three pores and dual permeability, using the effective wellbore diameter and the principle of Duhame superposition, taking into account the bottom hole pressure effect, and draws sample curves for the analysis of inclined wells in fractured and vuggy reservoirs. This provides a reference for the analysis of inclined wells in fractured and vuggy reservoirs.

Keywords: Well Testing Interpretation; Homogeneity; Fractured and Vuggy Reservoirs; Three Pore Media.

1. Introduction

At present, inclined wells have been widely used in oilfield production. Conducting research on inclined well testing models and understanding the laws of underground fluid seepage are important means to ensure efficient oilfield development[1]. For the study of inclined well testing theory, many scholars have used methods such as Green's function, Laplace transform, and point source function superposition to establish and solve inclined well testing models for homogeneous infinite reservoirs and homogeneous reservoirs with complex outer boundaries[2]. They have obtained analytical solutions for bottom hole pressure and analyzed their fluid flow patterns. Scholars have conducted research on inclined well testing models for dual porosity medium reservoirs with developed natural fractures[3].

2. Study on Flow Mechanism of Fractured and Caved Carbonate Reservoir

The flow mechanism of fractured carbonate reservoirs is complex, mainly due to the multi-scale nature of the reservoir space, especially the development of large-scale karst caves, and the presence of unfilled or semi filled large-scale karst caves. However, there is currently no unified conclusion on the study of fluid flow patterns in large-scale karst caves[4]. Therefore, it is necessary to conduct research on the flow mechanism of fractured carbonate reservoirs. This article focuses on studying the flow mechanism of fluids in large-scale karst caves through theoretical analysis and numerical simulation methods.

2.1. Theoretical Analysis Method

Consider the flow of fluid in an unfilled large-scale cave and simplify it to flow in a uniform circular tube. In a laminar state, the flow satisfies Poiseuille's law:

$$q = \frac{\pi r^4 \Delta p}{8 \mu \Delta L}$$

In the formula:

Δp is the pressure difference at both ends of the circular tube, Pa;

ΔL is the length of the circular tube, m;

Q is the flow rate through the circular tube, m^3/s;

R is the radius of the circular tube, m;

μ is the viscosity of the fluid, Pa*s.

In the state of laminar flow, the flow of fluid in porous media satisfies Darcy's law:

$$q = \frac{AK\Delta p}{\mu \Delta L}$$

In the formula:

A is the cross-sectional area of the medium;

K is the permeability of the medium.

We can consider a uniform circular tube as a porous medium when the porous medium is in the shape of a uniform circular tube and Å Å 1, and establish the relationship between Poiseuille's law and Darcy's law. In this case, the equivalent permeability of the circular tube is:

$$K = \frac{\pi r^4}{8A} = \frac{\pi r^2}{8}$$

When the radius of the circular tube is 1m, its equivalent permeability is $\pi/8\times10^{12}$ mD, it can be seen that the permeability of unfilled large-scale karst caves is very good, and the propagation speed of pressure in unfilled large-scale karst caves will be very fast.

2.2. Numerical Simulation Method

The theoretical analysis method simplifies a large-scale karst cave into a uniform circular tube[5]. Although it is easy to understand, the boundary of the large-scale karst cave considered is too regular and the compressibility of the large-scale karst cave and fluid is not considered. Below, COMSOL software will be used to establish a small-scale model of the actual oil reservoir based on similarity criteria, and numerical simulation methods will be used to study the situation of considering large-scale karst caves and fluid compressibility, The flow pattern of fluids in large-scale karst caves with irregular boundaries. COMSOL is a multi-physical field coupling software that has great advantages in handling complex boundaries and coupled flows through finite element methods. Considering reservoirs characterized by large-scale karst caves, there are two large-scale karst caves developed in the reservoir, and there is a high permeability channel formed by faults and associated fractures between them, and neither of the two large-scale karst caves is filled. Considering that the flow of fluid in large-scale karst caves is free flow, and the flow in fractures is Darcy's law, based on similarity theory, a coupled model of free flow seepage in fractured carbonate reservoirs is established, as shown in Figure 1.

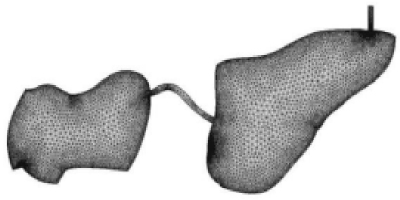

Figure 1. COMSOL Model Grid Splitting Diagram

And take 9 monitoring points in the model, as shown in Figure 2. From left to right, point A, point B, point C, point D, point E, point F, point G, point H, and point I. Point A and point B are distributed at both ends of the large-scale karst cave on the left, point C, point D, point E, point F, and point G are sequentially distributed on the crack, and point H and point I are distributed at both ends of the large-scale karst cave on the right.

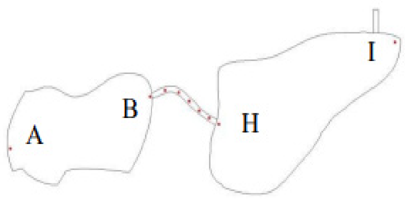

Figure 2. Distribution of Monitoring Points in COMSOL Model

Figure 3 is the pressure distribution map of the model, and Figures 3-33 are the contour distribution map of the model pressure. From Figures 3-32 and 3-33, it can be intuitively seen that pressure loss mainly occurs in high permeability channels formed by fractures and associated fractures, and the pressure drop in unfilled large-scale karst caves is particularly small.

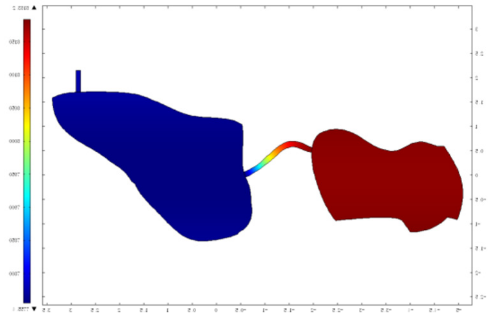

Figure 3. Pressure distribution diagram

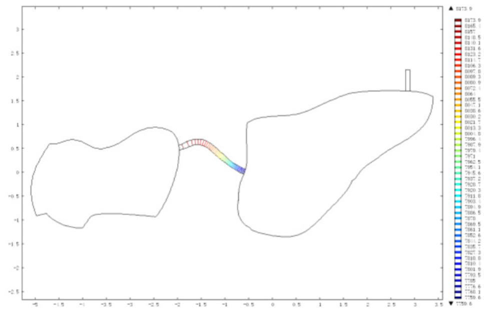

Figure 4. Pressure contour distribution map

Figure 5 shows the semi logarithmic relationship curve between pressure and time at each monitoring point. From Figure 5, it can be intuitively seen that during the process of relying on the elastic energy of the reservoir for exploitation, the pressure at each point shows a downward trend, and the closer the distance to the oil well, the smaller the pressure; The curves of points A and B coincide, while the curves of points H and I coincide. The pressure difference between points A and B, as well as the pressure difference between points H and I, is very small.

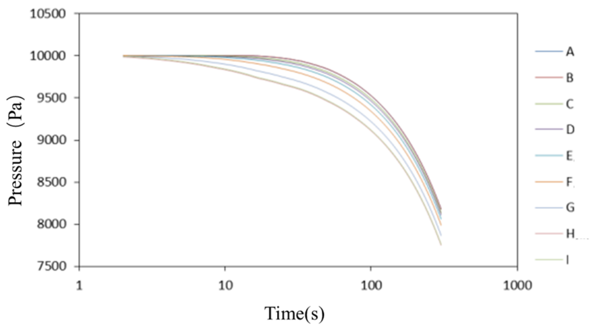

Figure 5. Semi logarithmic relationship between pressure and time at each monitoring point

Record P_{AB} as the average pressure difference between points A and B, P_{HI} as the average pressure difference between points H and I, P_{BH} as the average pressure difference between points B and H. H_{AB}, H_{HI}, and H_{BH} are the height differences between points A and B, H, and I, respectively. PAB=9.47 (Pa); PHI=16.47 (Pa); PBH=428.3 (Pa); HAB=0.7 (m); HHI=1.2 (m); HBH=0.5 (m).

The ratio of pressure drops between AB section, HI section, and BH section after eliminating the influence of gravity is:

$$\frac{P_{AB} - \rho g H_{AB}}{P_{BH} - \rho g H_{BH}} = 0.937\%$$

$$\frac{P_{HI} - \rho g H_{HI}}{P_{BH} - \rho g H_{BH}} = 1.649\%$$

It can be seen that pressure loss mainly occurs in cracks, and the pressure loss in large-scale karst caves can be ignored. It is believed that the pressure difference between points A and B represents the pressure difference at both ends of the left large-scale karst cave, the pressure difference between points H and I represent the pressure difference at both ends of the crack, and the pressure difference between points B and H represents the pressure difference at both ends of the right large-scale karst cave.

Based on theoretical analysis and numerical simulation methods, the following conclusions can be drawn: the propagation speed of pressure is particularly fast and the pressure drop is very small in the unfilled or semi filled areas of large-scale karst caves. If we only care about the distribution and propagation of pressure, we can consider the unfilled or semi filled parts of large-scale karst caves as equipotential bodies. This approach has the following advantages: (1) it ignores the influence of irregular boundaries of large-scale karst caves, so we can simplify it into a sphere, solving the problem of difficulty in characterizing large-scale karst caves; (2) Without considering the description of the internal flow of an equipotential body, the equations considering its internal flow are often very complex and difficult to solve, making it convenient for subsequent solutions.

3. Analysis Model of Three Hole and Double Permeability Well Testing in Fractured and Caved Reservoirs

3.1. Physical Model

Establish a physical model for the analysis of three hole dual permeability well testing in a fractured and vuggy reservoir with inclined wells, assuming the following conditions: 1) production with fixed production rate in inclined wells; 2) The reservoir is a triple porous medium composed of matrix, natural fractures, and karst caves, taking into account the dual permeability seepage of matrix wellbore and matrix fracture wellbore, as well as the situation where karst caves simultaneously flow towards the matrix and fractures; 3) The reservoir is horizontal, equally thick, and has impermeable boundaries at the top and bottom, with infinite outer boundaries in the horizontal direction; 4) Both reservoir rocks and crude oil can be slightly compressed, and the compression coefficients of matrix, karst caves, and fractures are all fixed values; 5) The permeability of the matrix and fractures is not equal in both horizontal and vertical directions[7].

3.2. Division of Flow Stages and Sensitivity Analysis of Well Testing Curves

3.2.1. Division of Flow Stages

Based on the calculated typical inclined well pressure of fractured and vuggy reservoirs, and based on the characteristics of the bottomhole dimensionless pressure and its derivative curve, the well testing curve is divided into 8 flow stages: the wellbore storage effect stage (Stage I), which reflects the flow characteristics of crude oil in the wellbore during the initial well opening period, has a derivative curve slope of 1; The skin effect stage (Stage II) reflects the pollution situation in the near wellbore area, and its derivative curve shows a hump shape; The early radial flow stage (Stage III), linear flow stage (Stage IV), and transitional flow stage (Stage V) that reflect the characteristics of inclined well seepage (Figure 6a-c) have derivative curves of horizontal, oblique, and arc lines, respectively; The derivative curves of the karst cave towards fracture flow stage (stage VI), karst cave towards matrix, and matrix towards fracture flow stage (stage VII), which reflect the fluid exchange between the triple media of the reservoir, all show a concave shape; The overall radial flow stage (Stage VIII) under infinite geological boundary conditions (Figure 6d) has a derivative curve slope of 0.

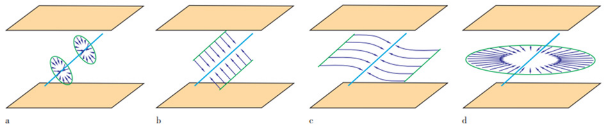

Figure 6. Schematic diagram of inclined well flow stage

3.2.2. Sensitivity Analysis

Based on the typical well testing curve flow stage division of fractured and vuggy reservoirs, this study investigates the influence of different well inclination angles and the permeability ratio of fractures to reservoirs on pressure, analyzes the sensitivity of different parameters to the curve and the flow stages that occur, in order to more accurately evaluate the production performance of fractured and vuggy reservoirs in deviated wells. The inclination angle of the well does not affect the well testing curve during the storage effect stage of the wellbore, but has a significant impact on the dimensionless pressure curve of all seepage stages. The larger the inclination angle of the well, the larger the drainage area of the oil well, the smaller the pressure drop required for extraction under constant production conditions, and the lower the position of the dimensionless pressure curve; The inclination angle of the well will have an impact on the pressure derivative curve before the channeling stage. The larger the inclination angle of the well, the lower the position of the pressure derivative curve in stages II to V, and the more obvious the early radial and linear flow characteristics. When the inclination angle of the well is 0 ° and 90 °, the inclined well test model becomes a conventional vertical well model and a horizontal well model, respectively. The corresponding test curves are the conventional vertical well test curve and the horizontal well test curve.

Set the well inclination angle to 45 ° and the wellbore length to 42.43m, with other parameters unchanged. Take the permeability ratios of fractures to reservoirs as 0.5, 0.7, and 0.9, and analyze their impact on the well testing curve. The ratio of permeability between fractures and reservoirs has an impact on the position of the dimensionless pressure curve in all seepage stages except for the wellbore storage effect stage and the overall radial flow stage. The larger the ratio of permeability between fractures and reservoirs, the higher the position of the pressure curve. However, the ratio of fractures to reservoir permeability only affects the pressure derivative curves of stages II-V and VII. The larger the value, the higher the position of the pressure derivative curve of stages II-V, the lower the position of the pressure derivative curve of stage VII, and the deeper the channeling concave (Figure 7). In addition, the influence of the channeling coefficient and elastic storage capacity ratio on the well testing curve is similar to that of the conventional three hole single permeability well testing model, and will not be repeated here.

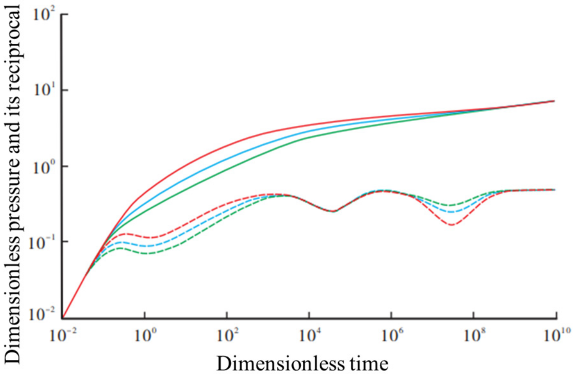

Figure 7. Impact of the ratio of fractures to reservoir permeability on the inclined well testing curve

4. Conclusion

(1) The typical well testing curves of inclined wells in fractured and vuggy reservoirs are divided into 8 fluid flow stages: wellbore storage effect stage, skin effect stage, early radial flow stage, linear flow stage, transitional flow stage, karst cave to fracture channeling stage, karst cave to matrix and matrix to fracture channeling stage, and overall radial flow stage.

(2) The well inclination angle mainly affects the position and shape of the curve in the skin effect stage, early radial flow stage, linear flow stage, and transitional flow stage of the inclined well testing curve. The larger the inclination angle of the well, the lower the position of the pressure derivative curve, and the longer the duration of early radial and linear flow.

(3) The larger the permeability ratio between fractures and reservoirs, the higher the position of the pressure derivative curve in the skin effect stage, early radial flow stage, linear flow stage, and transitional flow stage, and the lower the position of the pressure derivative curve in the karst cave to matrix and matrix to fracture channeling stage.

References

[1] Yue Dali, Lin Chengyan, Wu Shenghe, et al. Application of quantitative characterization method for reservoir heterogeneity in the development of reef limestone oil fields [J]. Journal of Petroleum, 2004, 25 (5): 75-79.

[2] Yu Xinghe. Fundamentals of Oil and Gas Reservoir Geology [M]. Beijing: Petroleum Industry Press, 2009. Wang Lien, Jiang Fudong. Quantitative Characterization Method for Heterogeneity of Carbonate Reservoir [J]. Natural Gas Technology, 2009, 3 (1) 27-29, 78.

[3] Chen Huanqing, Wang Jue, Du Yijing. Progress in Research Methods for Reservoir Heterogeneity [J]. Journal of University Geology, 2017, 23 (1): 104-116.

[4] FITCH P J R, LOVELL M A, DAVIES S J, et al. A integrated and quantitative approach to petrophysical hematogenity [J] Marine and Petroleum Geology, 2015, 63:82-96.

[5] Huang Sijing. Diagenesis of Carbonate Rocks [M]. Beijing: Geological Publishing House, 2010. HUANG Sijing. Diagenesis of Carbonate Rocks [M]. Beijing: Geo logical Publishing House, 2010.

[6] ABDULAZIZAM, HAWARY S S. Prediction of carbon dioxide emissions from well logs using artificial neural network: An innovative technology to understand complex carbon systems [J] Ain Shams Engineering Journal, 2020, 11 (4): 1387-1 401.

[7] Liu Jingshou, Ding Wenlong, Xiao Zikang, et al. Research progress on comprehensive characterization and prediction of reservoir fractures [J]. Progress in Geophysics, 2019, 34 (6): 2283-2300.

[8] CILONA A, FAULKNER D R, TONDI E, et al. The effects of rock heterogeneity on compaction localization in porus carbonates [J] Journal of Structural Geology, 2014, 67:75-93.

[9] THOMASH, BRIGAUDB, BLAISE T, et al. Contribution of drone photogrammetry to 3D output modeling of factors, porosity, and performance indicators in carbon reserves (Paris Basin, Middle Jurassic) [J]. Marine and Petroleum Geology, 2021123:104772.