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Study on igneous rock reservoir

Zhaoyuan Shao[1], Ning Ning[2], Fang Zhao[1], Jiewen Sun[2]
[1]Institute of Porous Flow and Fluid Mechanics, Chinese Academy of Science, Langfang, Hebei 065007, (CHINA)
[2]Langfang Branch, Research Institute of Petroleum Exploration and Development, Langfang, Hebei 065007, (CHINA)
E-mail: desfsf@163.com

ABSTRACT

The characteristics of igneous rock reservoir are extremely complicated. It is difficult to develop effectively. In response to the reservoir characteristics, set the gas reservoir in southern Songliao Basin as an example. The experiments study on lithology of igneous rock reservoir, its permeability and pore characteristics were carried out to provide basis for the effective development of gas reservoirs. The results have shown the following points: the igneous rock reservoir has low porosity and permeability, The rock properties are mainly andesite, rhyolite and volcanic breccia and the main reservoir space types are apertures. The flow characteristic was related to the reservoir permeability and pore pressure. The reservoir which has the permeability higher than 0.05mD was prone to high speed non-Darcy effect. According to the experiment data, different flow regimes of permeability and pore pressure were divided. The threshold pressure gradient is existed in the watercut and dense igneous rock reservoir but the pore type and fracture type reservoirs have obvious difference. The differences were small when the water saturation was high. When the water saturation was lower than 65%, threshold pressure gradient of fracture type was much lower than the pore type. So for the high water saturation reservoir, fracturing should be used to change the seepage channel in order to lower the reservoir threshold pressure gradient.

KEYWORDS

Igneous rocks; SEM; Slippage effect; Threshold pressure gradient.

INTRODUCTION

Igneous reservoirs have fast-changing lithofacies, complex internal structures and genetic mechanisms, various lithologies and diversified reservoir spaces, as well as significantly changed reservoir thickness and physical properties[1,2]. The complex geological features lead to multiple forms of water and gas distribution and complex flow mechanisms. By far, many studies have conducted on igneous reservoir features[3,4], but few on flow behaviors[5-8]. In this paper, typical igneous gas reservoirs in the southern Songliao Basin are discussed to identify reservoir features and flow mechanism, through mercury intrusion, SEM, casting thin sections and threshold pressure gradient tests. The results will be significant for further understanding the flow behaviors and guiding the development of igneous gas reservoirs.

RESERVOIR FEATURES

Lithology

The proposed igneous gas reservoirs are mainly composed of andesite, rhyolite, tuff and volcanic breccias, with average clay content of 17.7% (5% to 48%).

Andesite with chloritization and porphyritic calcilization has andesitic and porphyritic textures, whose matrix mainly comprises moderate-basic plagioclase and vitreous material. Rhyolite has porphyritic and micro-porphyritic textures, whose matrix has spherulitic and rhyolitic-felsitic textures and rhyolitic structure, and its phenocrysts are mainly quartz, alkali feldspar and plagioclase. Volcanic breccias mainly include andesite, tuff and minor metamorphic rocks, with significant argillization or alteration. Clay minerals are dominated by illite and illite-montmorillonite (Figure 1-a), followed by chlorite (Figure 1-b).

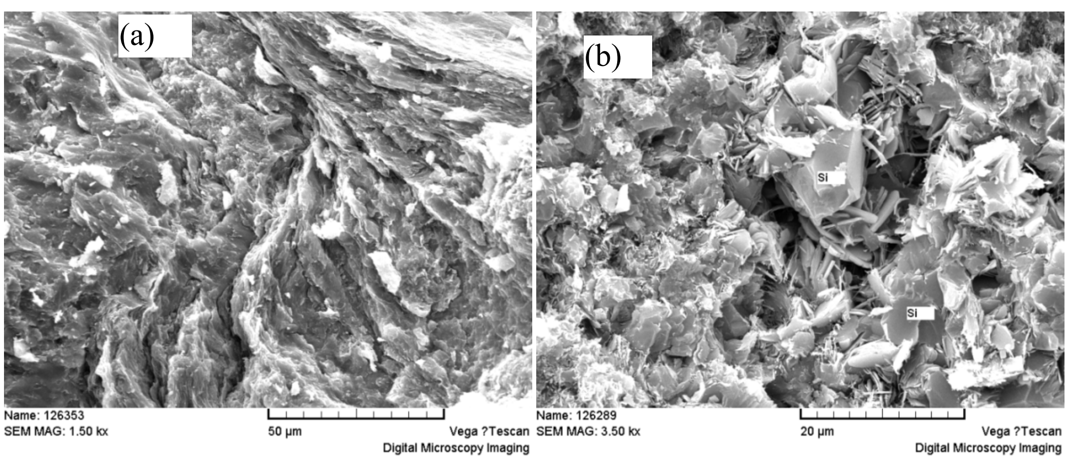


Figure 1 : Igneous rocks under SEM

Pore structure

Analysis of core casting thin section reveals the pore-fracture reservoir space, with surface porosity of 1%~30% or averagely5%. The pores are mainly intragranular and intergranular dissolved pores, intergranular and intercrystalline micro-pores, and minor mold pores and intercrystalline micro-pores of clay minerals (Figure 2-a). Micro-fractures are widely developed in reservoirs, with fracture width of 1-40μm. Rhyolite and andesite contain few structural fractures (Figure 2-b). Core capillary pressure curves of igneous gas reservoir are shown in Figure 3. And Figure 3-a can be analyzed to derive the results in TABLE 1.

TABLE 1 : Capillary pressure curve pressure and pore size distribution frequencies

Curve type	Curve features	Displacement pressure / MPa	Conclusions
Type I	Located in upper right, as high slope type, maximum mercury saturation less than 50%, with no median pressure and median radius.	3~14	Poor sorted pore throats and tiny throat radius.
Type II	Located in upper part, long gentle section in middle part	1.5~5.5	Well sorted pore throats, fine crooked degrees, small throat radius, reservoir properties better than that of Type I.

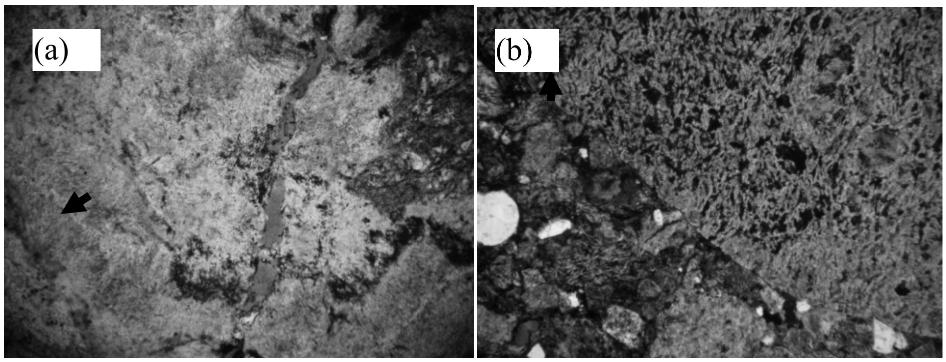
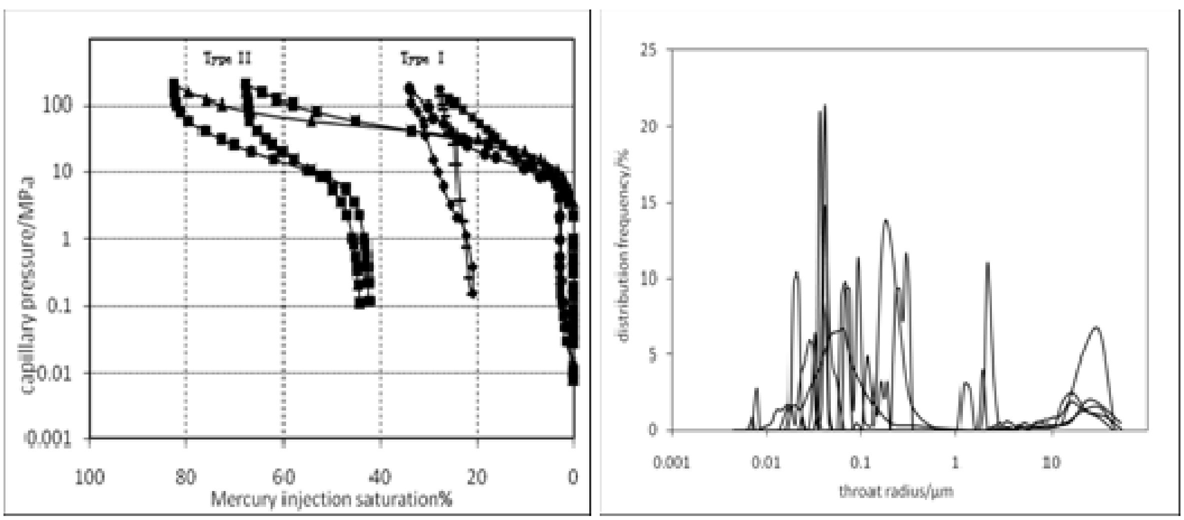


Figure 2 : Core casting thin section of igneous gas reservoir



(a) (b)

Figure 3 : Capillary pressure curve and pore size distribution frequency curve

Analysis of Figure 3-b shows that the pore throat size of igneous gas reservoirs ranges in 0.001~50.1μm, or 0.01~0.1μm as presented by 80% pore throats, and large pore throats (e.g. dissolved pores and micro-fractures) are developed in a small amount.

Reservoir physical properties

Conventional core tests suggest that the reservoir permeability is $(0.001\sim20)\times10^{-3}\mu m^2$, mainly $<0.1\times10^{-3}\mu m^2$, implying few high values, and the porosity is 2~25%, mainly 5~14%, indicating the reservoirs as low porosity-tight igneous gas reservoirs. NMR results show that the reservoirs feature high irreducible water saturation (30%~90%, and mainly 40%~75%) - the lower the permeability, the higher the irreducible water saturation is.

FLOW TEST

Flow test was conducted at room temperature. Gas drive water method was used to determine the water saturation of rock samples. Simulated formation water, nitrogen and data measured under the overburden pressure conditions were used.

Gas flow test

Twelve cores of igneous gas reservoirs with different lithologies and permeability were selected to identify the flow behaviors of the single phase in igneous cores. According to the relationship between flow rate and square difference gradient of pressure, the Klinkenberg's method[9] was applied to understand the relationship between gas permeability and reciprocal curve of average pressure ("Klinkenberg curve"). The results indicate that cores with different permeability have different gas flow behaviors, as shown in Figure 4 and Figure 5.

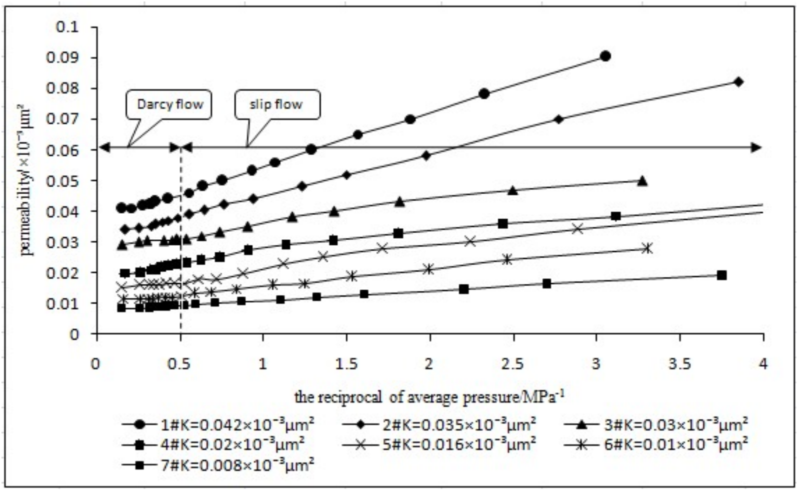


Figure 4 : Klinkenberg curve of rock samples with permeability less than 0.05×10-3μm2

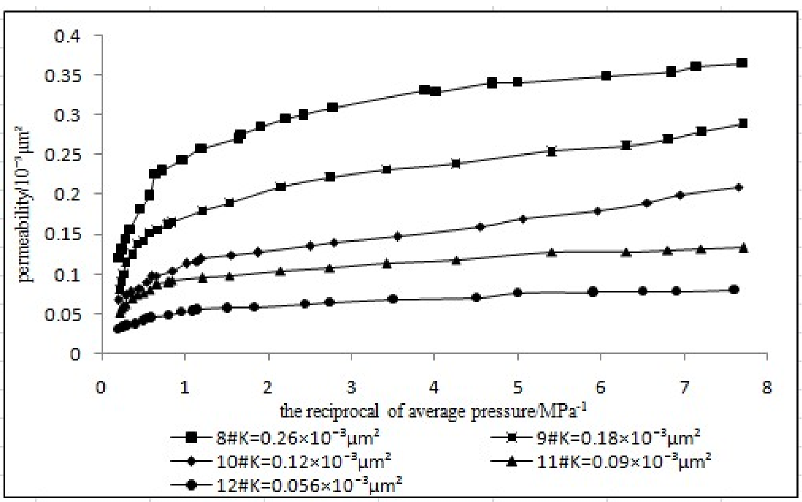


Figure 5 : Klinkenberg curve of rock samples with permeability more than 0.05×10-3μm2

It is seen from Figure 4 and Figure 5 that the Klinkenberg curves of igneous cores roughly reflect two types of flow regimes by taking $0.05\times10^{-3}\mu m^2$ as a boundary. Firstly, the flow regimes of cores with permeability less than $0.05\times10^{-3}\mu m^2$ are Darcy flow and slip flow (Figure 4), with critical pressure of

2MPa (0.5 MPa in Figure 4). When the pressure is less than 2MPa, the gas flow corresponds to slip flow as described by Klinefelter curve, where the smaller the average pressure, the greater the apparent permeability. When the pressure is greater than 2MPa, the gas flow basically matches with Darcy flow, where the permeability does not change with pressure. Secondly, the flow regimes of cores with permeability more than $0.05\times10^{-3}\mu m^2$ are turbulent flow and slip flow (Figure 5), with critical pressure of 1MPa. When the pressure is less than 1MPa, the gas flow corresponds to slip flow. When the pressure is more than 1MPa, nonlinear flow regime of turbulent flow will appear, where the greater the permeability, the more severe the turbulent flow and the lower the pressure (the higher the average pressure reciprocal). Flow equation follows Forchheimer's equation[10].

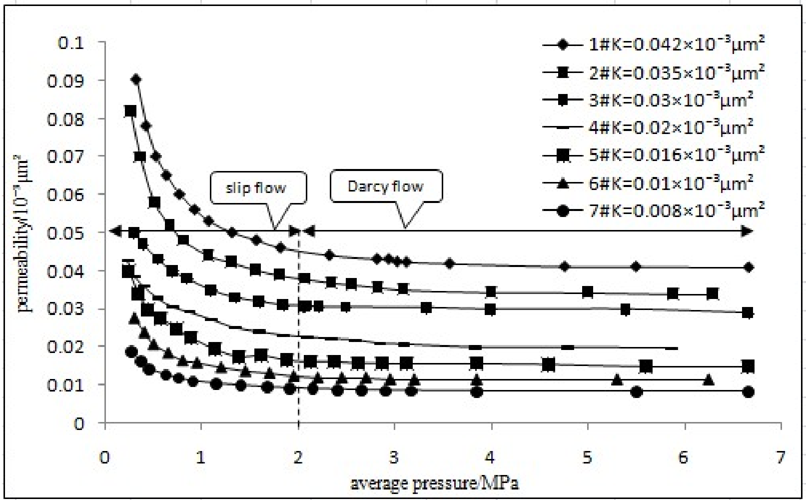


Figure 6 : Relation curve of permeability and average pressure

The flow regime of cores with permeability less than $0.05\times10^{-3}\mu m^2$ can also be expressed by the relationship between average pressure and permeability (Figure 6). When average pressure is less than 1MPa, the permeability decreases rapidly with the increase of average pressure. When average pressure is more than 2MPa, the permeability basically remains unchanged. So, the flow regime matches with Darcy flow.

Analysis of Figures 4~6 shows that the gas flow in tight igneous cores corresponds to three regimes: Darcy flow, slip flow, and turbulent flow. Cores with different magnitudes of permeability present different flow regimes (TABLE 2).

TABLE 2 : Core permeability and flow regimes

Core type	Type a		Type b	
Permeability, $\times10^{-3}\mu m^2$	**>0.05**		**<0.05**	
Critical pressure, MPa	>1	<1	>2	<2
Flow regime	Turbulent flow	Slip flow	Darcy flow	Slip flow

Analysis above indicates that pressure of 1~2MPa is the critical point at which the gas flow regime in low-permeability igneous gas reservoirs will break over. Slippage effect is negligible, since formation pressure is much greater than 2MPa. However, the turbulent effect possibly generated when the gas flows at high speed around bottom hole should be considered.

Figure 7 is the curve fitting between gas flow rate and square difference gradient of pressure, suggesting that Type a cores present good binomial relation, namely $v = a\left[\frac{\Delta p^2}{L}\right]^2 + b\left[\frac{\Delta p^2}{L}\right] + c$, while Type b cores represent linear relation, namely $v = m\left[\frac{\Delta p^2}{L}\right] + n$, where a, b, c, m and n are fitting constants. When the square difference gradient of pressure is zero, the intercept of flow curve in flow velocity axis is positive, in other words, a "pseudo-initial flow rate" exists when the square difference gradient of pressure is zero. Such flow rate means that gas is influenced by slippage effect in dry cores.

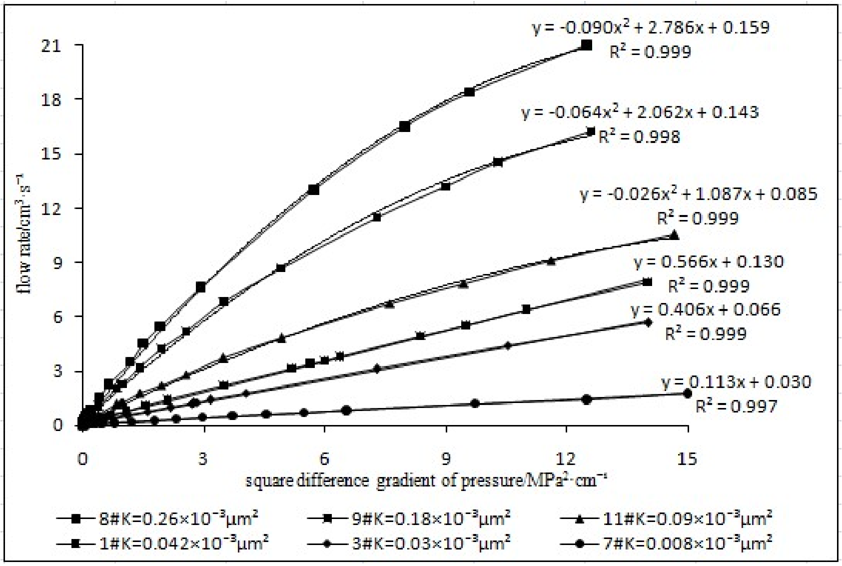


Figure 7 : Relation curve of flow rate and square difference gradient of pressure

Threshold pressure gradient test

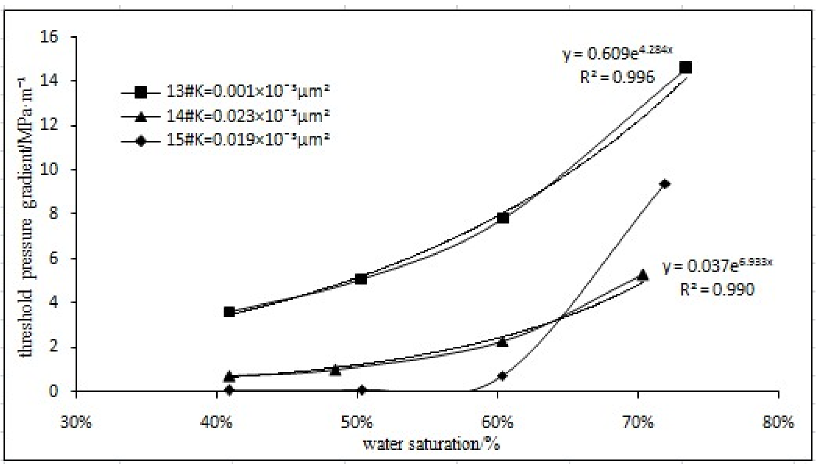


Figure 8 : Relation curve of threshold pressure gradient and water saturation

Three cores with different porosity and permeability were selected to identify the threshold pressure gradients of such igneous cores under different water saturations. As shown in Figure 8, the threshold pressure gradient is associated with permeability and irreducible water saturation - the lower the permeability, the greater the threshold gradient; the higher the water saturation, the greater the threshold gradient. When the water saturation is lower than 60%, the threshold pressure gradient changes slightly. When the water saturation is greater than 60%, the threshold pressure gradient increases rapidly.

For No.15 core which is a fracture core, when water saturation is less than 60%, the threshold pressure gradient is very small. For No.13 and No.14 cores which are pore cores, the threshold gradient increases exponentially with the increase of water saturation. For fracture cores in which flow space is even and there is no abrupt change of pore and throat, when water cut is low, water film is less thick and causes small flow resistance on gas, and water cut has small influence on threshold pressure gradient. Fore pore cores with staggered pores and throats, since water film closes the small pore throats, gas flows in form of small bubbles which will generate Jamin effect in each throat. Therefore, the capillary resistances which lead to Jamin effect along displacement direction are superimposed and present generally that the higher the water saturation, the greater the threshold pressure gradient.

CONCLUSIONS

(1) The igneous gas reservoirs are mainly composed of andesite, rhyolite and volcanic breccias, with pores and fractures as reservoir space. They are low porosity tight reservoirs.

(2) When the pore pressure is 1~2MPa, the single-phase flow regime of gas breaks over in igneous rocks. Relation curve of flow rate and square difference gradient of pressure indicates two types of flow regimes by taking $0.05\times10^{-3}\mu m^2$ as a boundary, namely, linear and nonlinear flow regimes.

(3) When the water saturation is less than 60%, the threshold pressure gradient of fracture cores changes slightly with the increase of water saturation, but the threshold pressure gradient of pore cores increases exponentially with the increase of water saturation. The fact that the threshold pressure gradient of fracture cores is significantly smaller than that of pored cores is favorable for the development of gas reservoirs.

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