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Original article

Mechanism and influence factor of hydrocarbon gas diffusion in porous media with shale oil

Ze Wanyan[1], Yishan Liu[1]*, Zhen Li[2], Chi Zhang[3], Yuqi Liu[1], Ting Xue[2]

[1]*Research Institute of Petroleum Exploration and Development, PetroChina, Beijing 100083, P. R. China*

[2]*Research Institute of Exploration and Development of Changqing Oilfield Company, Xi'an 710018, P. R. China*

[3]*Petroleum Engineering Department, Colorado School of Mines, Golden 80401, America*

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Abstract:
Due to the compactness of shale reservoir matrix and the high conductivity of fractures, the hydrocarbon gas injection huff and puff method or displacement is the most realistic technology to improve shale oil recovery. The diffusion mechanism plays an important role in shale oil development; therefore, it is crucial to figure out the factors influencing diffusion, which could enhance shale oil recovery. In this paper, a physical simulation experiment is designed to evaluate the diffusion ability of hydrocarbon gas. Diffusion experiments are conducted to simulate diffusion in the bulk fluid and in the porous media, to learn about how the pressure, permeability and fracture affect the diffusion behavior. The diffusion coefficients between the bulk diffusion and core sample diffusion are compared. The experimental results show that the diffusion coefficient and mass transfer capacity are positively correlated with permeability and pressure: increasing these parameters can promote the diffusion process. The diffusion coefficient of hydrocarbon gas in a saturated oil core is significantly less than that in crude oil, which indicates that the porous media seriously affects the process of gas diffusion in crude oil. Fractures have little impact on the diffusion behavior. Combined with numerical simulation, the influencing factor of diffusion on the development effect of hydrocarbon gas injection is clarified. The recovery enhances and then decreases with the increasing diffusion coefficient.

1. Introduction

Shale reservoirs differ from conventional reservoirs in that fracturing is required before development; during the volume fracturing development stage, the production capacity declines rapidly. In this respect, the current improvement of shale oil development is in a critical stage, and it is urgent to effectively improve recovery technologies (Aguilera et al., 2014). The annual decline rate of the initial shale oil wells exceeded 30%, 1/3 of the wells could not reach the output designed in the scheme, and it was difficult to achieve the benchmark yield of 6% (Mohanty et al., 2019). The research and testing of enhanced oil recovery (EOR) technology throughout its life cycle is in its infancy, and the efficiency and stable production of the oilfield are facing great challenges (Singh, 2018).

The recovery of shale oil depletion is less than 10% (Yang et al., 2015). In the case of volume fracturing development using the existing technology, the movable reserves of tight/shale oil are low, and the development effect is poor; thereby, it is urgent to take measures to improve production and recovery (Aziz et al., 2009; Mukherjee et al., 2020). However, at present, the mass transfer and displacement mechanism of gas flooding is unclear, the gas injection mode and its applicability have not been established, and gas channeling occurs in many gas injection pilot tests (Wang, 1996; Alfarge et al., 2018; Janiga et al., 2018). The poor effect of reservoir energy supplement seriously restricts the development of gas injection (Alfarge et al., 2017; Jia et al., 2018).

The injected gas is divided into hydrocarbon gases and non-hydrocarbon gases. Non-hydrocarbon gases are mainly nitrogen and carbon dioxide, while hydrocarbon gases include

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*Corresponding author.
E-mail address: wanyanze@petrochina.com.cn (Z. Wanyan); lys2010021519@163.com (Y. Liu); lizhenlz_cq@petrochina.com.cn (Z. Li); chizhang1@mines.edu (C. Zhang); liuyuqi19971129@163.com (Y. Liu); xt519_cq@petrochina.com.cn (T. Xue).
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produced gas, methane, propane and butane (Etminan et al., 2010; Sæle et al., 2022). The type of injected gas determines its dissolving ability in crude oil (Ertas et al., 2006; Atchariyawut et al., 2008). The higher the diffusion coefficient of the gas, the easier the gas will enter the crude oil, and the better the effect of improving the nature of the crude oil, increasing its liquidity and realizing the process of mixing with the crude oil (Mavroudi et al., 2006; Cronin et al., 2019). The gas cap formed by the low-density free gas accumulates in the upper part of the reservoir and drives the crude oil to the bottom of the well by gravity differentiation (Rani et al., 2018). Therefore, the gas diffusion coefficient is not only an important parameter for analyzing the mechanism of gas injection EOR, but also a vital guiding factor for the subsequent gas injection development mode and parameter optimization (Unatrakarn et al., 2011).

To date, gas injection has become one of the most effective EOR technologies of shale oil development. Shengli, Huabei and other oilfields have carried out laboratory experiments and field tests of gas injection and achieved satisfactory results. It is found that the research on steam flooding, carbon dioxide flooding and nitrogen flooding in tight reservoirs is relatively mature, while studies on hydrocarbon gas flooding such as natural gas have been less frequent. A small number of studies are mainly focused on indoor experiments, and those on the mass transfer mechanism of hydrocarbon gas displacement, such as natural gas, have been scarce (Shu et al., 2016; Fayazi et al., 2018).

The gas diffusion coefficient is the most important parameter to measure diffusion and mass transfer (Zhang et al., 2000). It is defined as the mass or mole number of a substance passing vertically through the unit cross-sectional area for each unit of concentration reduction along the diffusion direction in unit time (Hummel et al., 2013). There are two methods to measure the diffusion coefficient of high-pressure gas in the liquid phase: the direct method and the indirect method (Mohammed et al., 2018). Direct measurement refers to obtaining liquid samples at different time intervals, obtaining the gas concentration according to component analysis, attaining the concentration distribution by using corresponding mathematical model, and finally, calculating the diffusion coefficient of gas in the liquid (Unatrakarn et al., 2011; Sharma et al., 2015).

In this paper, indoor experiments and numerical simulation are combined. The diffusion coefficients of hydrocarbon gases in different media are compared and analysed, and the factors affecting the diffusion behaviour in porous media are comprehensively considered. Combined with the field development mode, the main stage of hydrocarbon gas diffusion and the importance of its impact on production capacity are expounded.

2. Materials and methods

2.1 Experimental method

In order to study the diffusion characteristics of hydrocarbon gases under different conditions, an experimental device was designed for hydrocarbon gas diffusion. The diffusion experiment of hydrocarbon gas crude oil system under different pressure conditions was carried out at the temperature of 70 °C, and the diffusion and mass transfer mechanism of hydrocarbon gas in bulk crude oil and in shale core porous media under the influence of different factors was concluded.

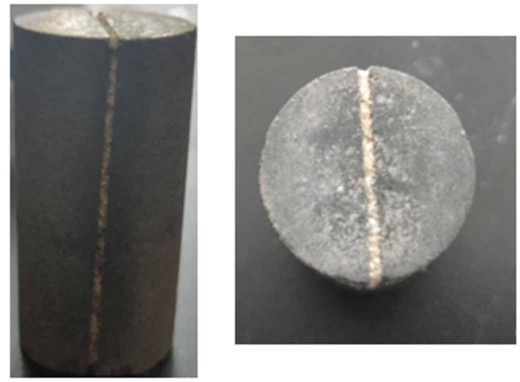

Fig. 1. Core sample: the left one is with penetrating fracture, and the right one is the fracture shape of core cross-section.

2.1.1 Materials

The simulated oil was prepared from degassed crude oil and kerosene in a certain proportion to ensure that the viscosity of the simulated oil is the same as that of the formation crude oil, which is 1.8 mPa·s (at 70 °C). The injected hydrocarbon gas was compounded with reference to the oilfield data, and its component ratio was CH_4: 77.52%, C_2H_6: 21.47%, CO_2: 1.01%. Matrix-fracture dual medium core models were built to simulate the pore-fracture structure in shale oil reservoirs (Fig. 1). The length of the artificial crack was 50 mm, the height was 1.4 mm, and the fracture conductivity was 95.23 mD · mm.

Manufacturing method and steps of matrix-fracture dual medium core:

1) Prepare the core of standard sample, with a diameter of 2.5 cm and a length of 5 cm.
2) Mix the AB glue evenly in a ratio of 1:1, then take an appropriate amount of 40-70 mesh quartz sand and mix it evenly (the volume ratio of glue and sand is about 1:10).
3) Fill the mixed mortar into the fracture evenly to ensure that the end face of the core is flush. Put it into the oven to dry for 6 hours.

2.1.2 Equipment

The experiments mainly include a hydrocarbon gas-crude oil diffusion experiment and a hydrocarbon gas-saturated oil core diffusion experiment. The experimental device shown in Fig. 2 was used to simulate the formation temperature of 70 °C. The diffusion experiment of hydrocarbon gas crude oil system was carried out under different pressure conditions, the evaluation standard of diffusion effect was established, and the characteristics and laws of hydrocarbon gas diffusion and mass transfer under the influence of different factors were clarified.

The experimental parameter settings are listed in Table 1. In the experiment, the diffusion coefficient measurement of

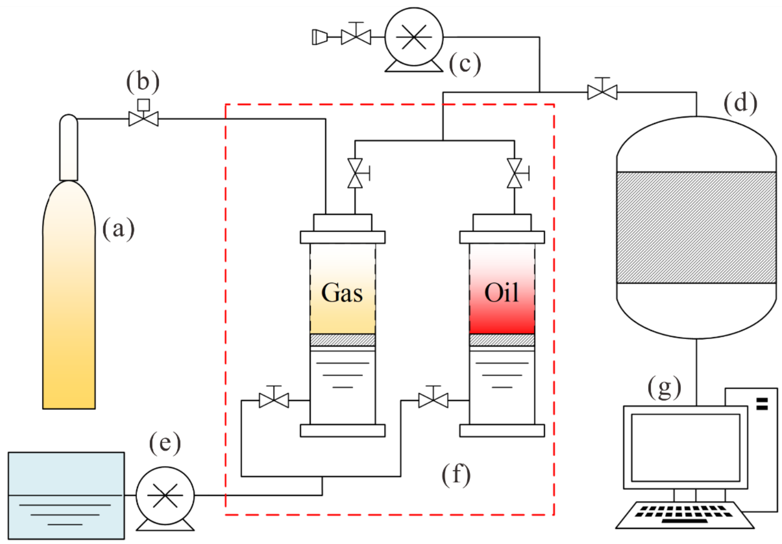

Fig. 2. Schematic diagram of gas diffusion experiment. (a) Hydrocarbon cylinder, (b) pressure relief valve, (c) vacuum pump, (d) high-temperature and high-pressure reactor, (e) ISCO pump, (f) intermediate container, (g) pressure data acquisition equipment.

Table 1. Experimental parameters of hydrocarbon gas diffusion.

Diffusion medium	Experimental condition		
	Pressure (MPa)	Permeability (mD)	With or without fractures
Bulk crude oil	20	/	/
	30	/	/
Shale core sample	20	0.170	N
	30	0.170	No
	30	0.074	No
	30	0.468	No
	30	38.740	Yes

hydrocarbon gas in the bulk fluid and the pore structure of shale core were designed, and the effects of pressure, permeability and fracture were compared.

2.1.3 Experimental process

(1) Diffusion experiment of hydrocarbon gas-bulk crude oil

(a) Pressurize the gas to the experimental pressure (20, 30 MPa), store it in the intermediate container, and place the intermediate container in the oven at 70 °C.

(b) Take 25 mL of simulated oil and place it in a high-temperature autoclave, vacuum for more than 6 hours, adjust the temperature in the autoclave to the experimental temperature, and age for 24 hours.

(c) Open the connecting valve between the intermediate container and the reactor, use an ISCO pump to displace the gas in the intermediate container until the gas pressure in the reactor reaches the experimental pressure, then close the connecting valve.

(d) A pressure sensing device connected to the above the reactor is used to record the pressure change data in the reactor with time.

(e) When the pressure data is stable, the experiment terminates.

(2) Diffusion experiment of hydrocarbon gas-crude oil in core sample

(a) Pressurize the gas to the experimental pressure (20, 30 MPa), store it in the intermediate container, and place the intermediate container in the oven at 70 °C.

(b) Vacuumize the core and saturate with oil, seal the two ends of the core with epoxy resin, and place the core vertically in the high-temperature and high-pressure reactor after the epoxy resin is cured.

(c) Adjust the temperature in the reactor to the experimental temperature and age for 24 h.

(d) Open the connecting valve between the intermediate container and the reactor, use the ISCO pump to displace the gas in the intermediate container until the pressure in the reactor reaches the experimental pressure, then close the connecting valve.

(e) A pressure sensing device connected to the above the reactor is used to record the pressure change data in the reactor with time.

(f) When the pressure data reaches a constant value, the experiment terminates.

2.2 Diffusion coefficient calculation

The diffusion coefficient governing equation is as follows (Zhang et al., 2000):

$$p(t) = p_{eq} + \frac{8BLC_{eq}}{\pi^2} e^{-D_e\left(\frac{\pi}{2L}\right)^2 t} \tag{1}$$

where $p(t)$ denotes the diffusion system pressure at time t, MPa; p_{eq} denotes diffusion equilibrium pressure, MPa; C_{eq} denotes the concentration of CO_2 in the pore, %; D_e denotes the diffusion coefficient, m^2/s; B denotes the diffusion area

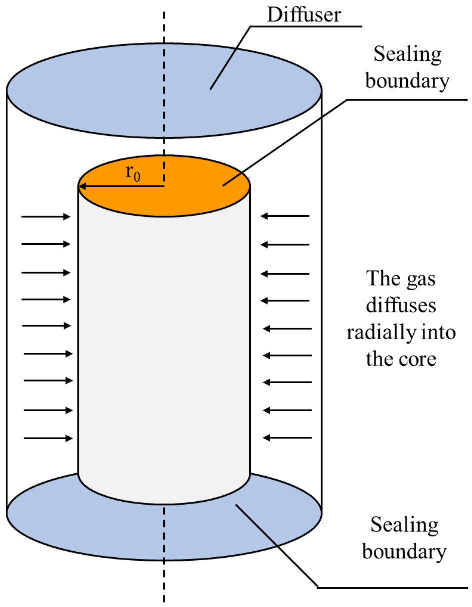

Fig. 3. Physical map of core physical model.

area of CO_2, m^2; L denotes the height of oil volume in the reactor, m; t is the diffusion time, s.

By changing the logarithm on both sides of the above formula, one can obtain:

$$\ln\left[p(t)-p_{eq}\right]=\ln\frac{8BLC_{eq}}{\pi^2}-D_e\left(\frac{\pi}{2L}\right)^2 t \tag{2}$$

Draw $\ln\left[p(t)-p_{eq}\right]\sim t$ relation curve in a rectangular coordinate system and calculate the diffusion coefficient D_e of hydrocarbon gas in crude oil from the slope m of the curve.

$$D_e=|m|\left(\frac{2L}{\pi}\right)^2 \tag{3}$$

where m denotes the slope of the 0.5th power relationship curve between diffusion chamber pressure and time.

The schematic model of hydrocarbon gas diffusion in saturated oil cores is shown in Fig. 3. Different from the directional differential pressure injection method in the displacement mode, in the diffusion experiment, the core of saturated oil is placed in a container full of hydrocarbon gas, such that all contact surfaces will become the entry channels of hydrocarbon gas. The governing equation is as follows:

$$\frac{\partial C}{\partial t}=D_{eff}^{'}\left(\frac{\partial^2 C}{\partial r^2}+\frac{1}{r}\frac{\partial C}{\partial r}\right),\quad 0<r<r_0,\ t\geq 0 \tag{4}$$

$$C|_{t=0}=0,\quad 0<r<r_0 \tag{5}$$

$$C|_{r=l_0}=C_0,\quad t\geq 0 \tag{6}$$

By solving the above formula, the diffusion coefficient calculation formula is obtained:

$$D_e=D_{eff}^{'}=\frac{\pi}{16}\left(\frac{r_0 mV}{N_\infty ZRT}\right)^2 \tag{7}$$

where C denotes the concentration of CO_2 in the pore at time, t; N_∞ denotes the amount of gas diffused into the core when the diffusion time tends to infinity, mol; l_0 denotes the diffusion initial position of CO_2; r_0 denotes the core radius, m; V denotes the volume of annular space formed between core and diffusion cylinder, m^3; R denotes the ideal gas constant, 8.314 $J/(mol\cdot K)$; T indicates the temperature, K; Z is the compression factor of hydrocarbon gas, which is obtained by referring to standing and Katz plates (Hoteit, 2011).

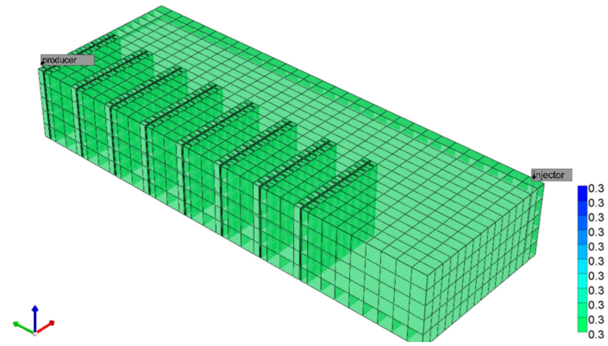

Fig. 4. Gas flooding mechanism model (water saturation).

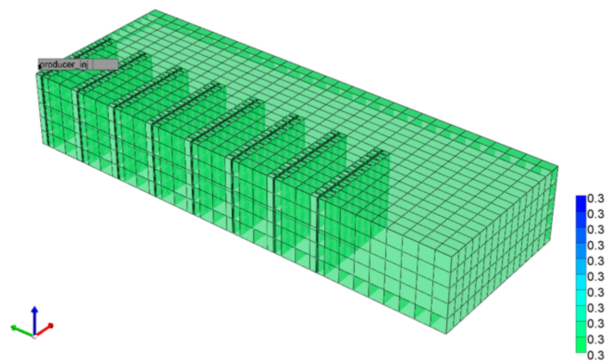

Fig. 5. Gas injection huff and puff mechanism model (water saturation).

The calculation method of the diffusion coefficient includes the following three main steps:

1) Draw the pressure curve of the diffusion chamber with time.
2) Draw the relation curve for the diffusion chamber pressure vs. time to the power of 0.5.
3) The diffusion coefficient is calculated according to the slope of the fitting line and other relevant parameters.

2.3 Numerical simulation

In order to further study the influence of diffusion coefficient on the development effect of hydrocarbon gas flooding, a gas flooding model was established based on the results of diffusion experiment (Fig. 4). The numerical simulation of hydrocarbon gas flooding with different diffusion coefficients was carried out, and the influence of diffusion coefficient on gas flooding under different parameter conditions was analyzed. The specific parameter settings are shown in Table 2.

Subsequently, we established the same numerical simulation mechanism model as that for natural gas flooding (Fig. 5). The numerical simulation of hydrocarbon gas huff and pu-

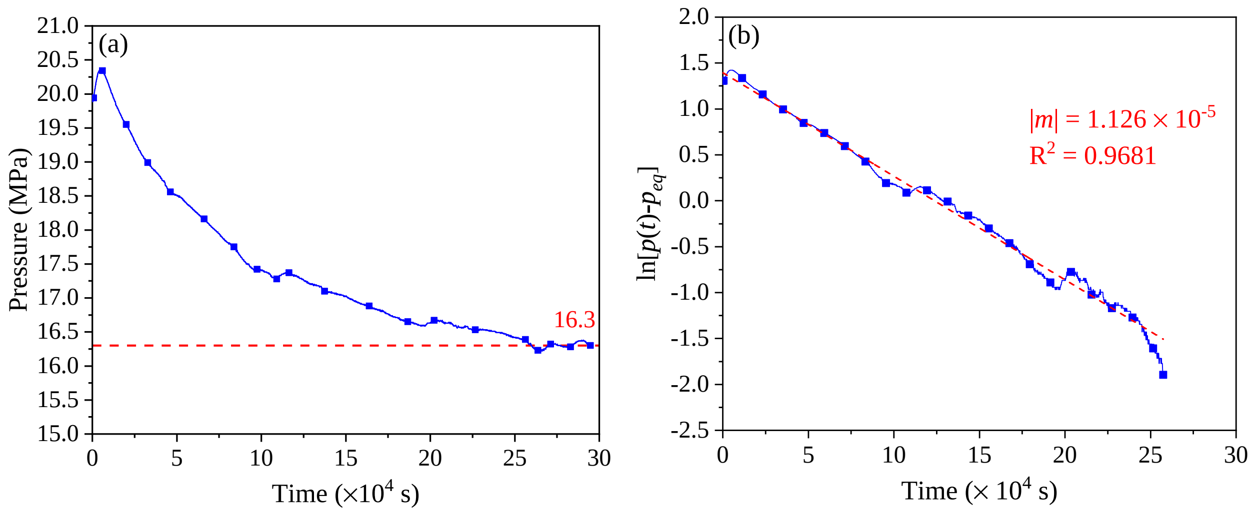

Fig. 6. Diffusion characteristic curve of gas-oil system at the initial pressure of 20 MPa. (a) Pressure versus time curve, (b) $\ln[p(t)-p_{eq}] \sim t$ relation curve.

Table 2. Geological model parameters.

Parameter	Value
Porosity (−)	0.099
Permeability (10^{-3} μm^2)	0.05, 0.1, 0.2, 0.5, 1.0
Initial oil saturation (−)	0.694
Temperature (°C)	70
Fracture spacing (m)	0.03, 0.1, 0.5, 1, 10
Gas injection pressure (MPa)	14, 16, 18, 20, 22
Diffusion coefficient (10^{-9} m^2/s)	0.5, 1, 2, 4, 8
Formation pressure (MPa)	14.841

ff technique under different diffusion coefficients was carried out, and the influence of diffusion coefficients on the huff and puff development under different parameters was analyzed.

3. Results and discussion

3.1 Diffusion ability of hydrocarbon gas

The variation curve of experimental pressure with time is shown in Fig. 6(a), and the equilibrium pressure is 16.21 MPa. Draw $\ln[p(t)-p_{eq}] \sim t$ relation curve as shown in Fig. 6(b), and the slope of curve fitting is 1.1276×10^{-5}; then, substitute the slope m into Eq. (3) to get $D_e = 5.717\times10^{-9}$ m^2/s. The pressure versus time curve with the initial pressure of 30 MPa is shown in Fig. 7(a), and the equilibrium pressure is 24.97 MPa. Draw $\ln[p(t)-p_{eq}] \sim t$ relation curve as shown in Fig. 7(b), and the slope of curve fitting is 1.356×10^{-5}; then, substitute the slope m into Eq. (3) to get $D_e = 6.875\times10^{-9}$ m^2/s.

From the data analysis, it can be found that the pressure of the whole system first decreases and then tends to stabilize in the process of hydrocarbon gas diffusion to crude oil at 70 °C. Under higher pressure, the pressure in the system needs less time to reach the equilibrium state. It can be seen that, under the condition of large concentration difference, hydrocarbon gas quickly diffuses into crude oil, and the gas diffusion speed slows down with the decline of concentration difference. Combined with field production, in the process of gas injection development, the effect of crude oil upgrading and viscosity reduction is the best in the initial stage of gas injection. Assuming that the gas and crude oil are homogeneous fluids, the diffusion front of gas in crude oil advances evenly. With the diffusion distance extending, the concentration of gas components in the diffusion front and the crude oil decreases, and the effect of crude oil modification becomes weaker. Compared with the 20 MPa low-pressure condition, the 30 MPa high-pressure condition increases the molecular density of hydrocarbon gas and crude oil, increases the probability of intermolecular collision, and intensifies the thermal movement of molecules, making it easier for them to diffuse; however, under the condition of high pressure, the molecular density of fluid is higher and the diffusion is more intense, which eliminates the diffusion limit, the diffusion distance becomes less and the equilibrium time is shorter under the same concentration difference.

The calculation results of diffusion coefficient under different pressure conditions are shown in Table 3. The experimental results show that the system pressure first decreases, and then tends to stabilize with time (Fig. 8). The higher the initial pressure, the greater the decrease in equilibrium pressure, and the longer the equilibrium time. Compared with diffusion in crude oil, the diffusion coefficient in the saturated oil core is obviously smaller. This is because in the core, the diffusion direction of gas is related to the distribution of fluid, while the diffusion of gas in the bulk fluid is directionless. In the core, the rock structure restricts the diffusion direction of gas, and the pore connectivity and tortuosity in the core will affect the gas diffusion rate.

The diffusion experiment in a saturated core considers the effect of porous medium on diffusion, which better reflects the

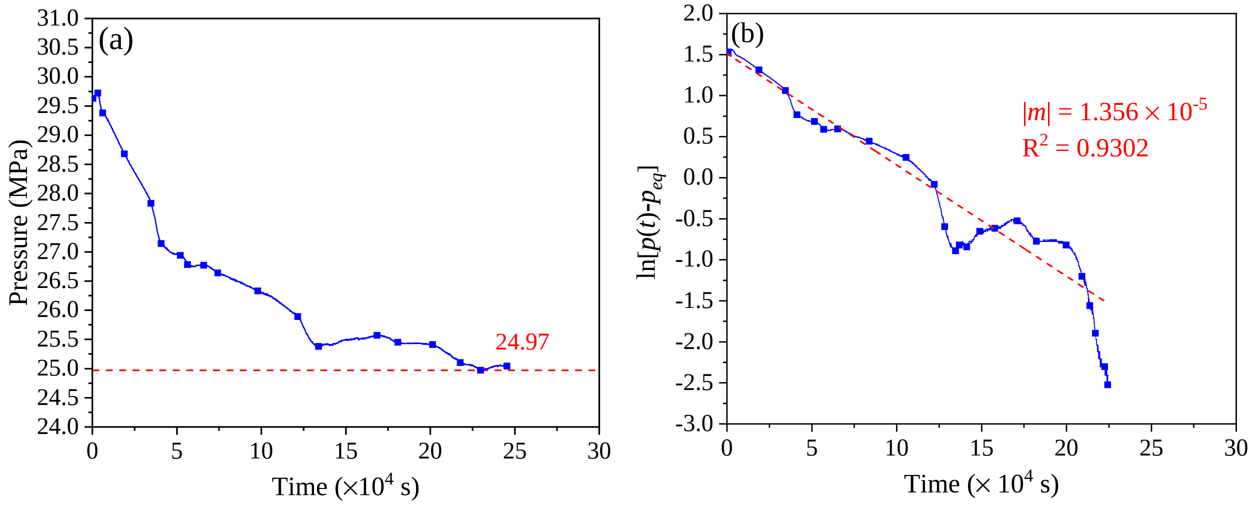

Fig. 7. Diffusion characteristic curve of gas-oil system at the initial pressure of 30 MPa. (a) Pressure versus time curve, (b) $\ln[p(t)-p_{eq}] \sim t$ relation curve.

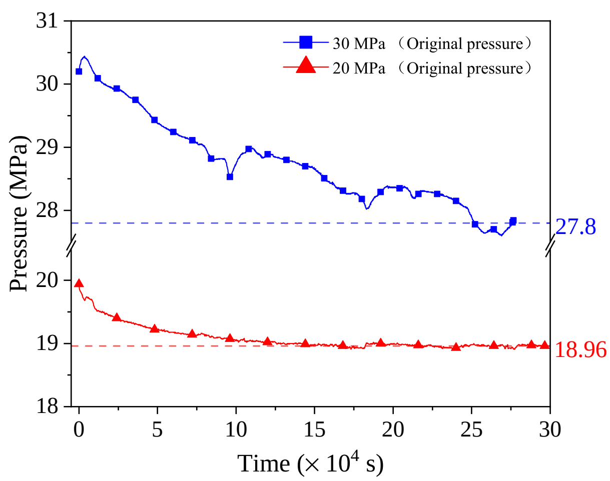

Fig. 8. Variation curve of pressure with time.

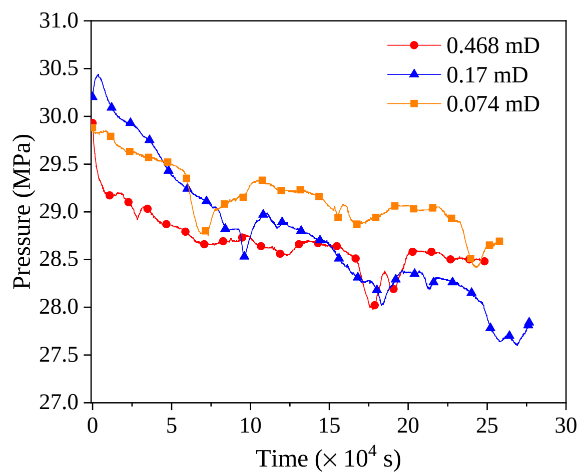

Fig. 9. Variation curve of pressure with time under 30 MPa.

diffusion behavior in reservoirs. Influencing factors such as pore connectivity and tortuosity will limit the direction of gas diffusion, and the pore structure will cause molecules to collide with the pore walls, thus affecting gas diffusion. Meanwhile, the bulk crude oil diffusion experiment is not affected by geological factors such as pore structure or pore size, so the diffusion coefficient obtained from the bulk crude oil diffusion experiment is larger than that from the saturated core diffusion experiment. The higher the pressure, the greater the diffusion coefficient, which is consistent with the law of gas diffusion in bulk fluid.

Fig. 9 shows the comparative analysis of diffusion coefficient of hydrocarbon gas in saturated oil rock core under different permeability/pore throat size values. The calculation results of diffusion coefficient under different pressure conditions are shown in Table 4. The parameters p and Z of the comparative experiments are fixed values at 30 MPa and 0.904, respectively. The experimental results show that the system pressure decreases first and then tends to stabilize. At 70 °C, the higher the core permeability, the larger the throat radius, the larger the proportion of oil-bearing pores controlled by the throat, and the easier the gas to diffuse in the oil-bearing pores. Therefore, higher permeability can reduce the equilibrium time (Fig. 9). The lower the complexity of diffusion trajectory caused by tortuosity, the easier the diffusion of hydrocarbon gas, and the greater the diffusion coefficient. However, they are basically in the same order of magnitude (10^{-9}), hence it can be further speculated that when the throat radius is greater than a certain value, the influence of permeability and throat radius on the diffusion coefficient begins to weaken.

Fig. 10 presents the pressure change over the entire diffusion process. The experimental results reveal that the system pressure decreases first and then tends to stabilize with time. As for the time requirement to reach to the equilibrium state, they are similar, which indicates that the fracture has little influence on the diffusion behavior. The calculation results of diffusion coefficient under different core conditions are shown in Table 5. The compression factor Z of hydrocarbon gas is 0.904. The diffusion coefficient of hydrocarbon gas in saturated oil fractured rock core is not much different from

Table 3. Calculation results for the diffusion coefficient under different pressure conditions.

p (MPa)	Z	V (cm^3)	N_∞ ($\times 10^{-9}$ mol)	p_{eq} (MPa)	$\lvert m\rvert$ ($\times 10^{-3}$)	D_e ($\times 10^{-9}$ m^2/s)
20	0.824 at 19.94 MPa 0.819 at 18.96 MPa	19.78	7.3	18.96	1.9909	0.931
30	0.9040 at 29.90 MPa 0.8847 at 28.03 MPa	19.78	9.6	27.80	4.1743	1.967

Table 4. Diffusion coefficient under different permeability conditions.

K (mD)	V (cm^3)	N_∞ ($\times 10^{-9}$ mol)	p_{eq} (MPa)	$\lvert m\rvert$ ($\times 10^{-3}$)	D_e ($\times 10^{-9}$ m^2/s)
0.074	17.78	4.6	28.90	2.027	1.63
0.170	19.78	9.6	27.80	4.174	1.967
0.468	21.21	8.6	28.48	3.790	2.32

Table 5. Calculation results of diffusion coefficient with or without fractures.

p (MPa)	K (mD)	V (cm^3)	N_∞ ($\times 10^{-9}$ mol)	p_{eq} (MPa)	$\lvert m\rvert$ ($\times 10^{-3}$)	D_e ($\times 10^{-9}$ m^2/s)
30 (without fracture)	0.074 (matrix)	17.78	4.6	28.90	2.027	1.630
30 (penetrating fracture)	0.069 (matrix)	25.22	12.5	27.98	3.429	1.586

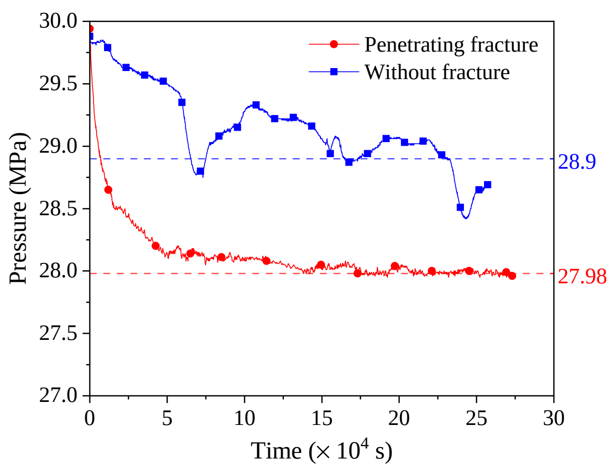

Fig. 10. Pressure versus time under 30 MPa and 0.074 mD, and sample without fracture.

that in core without fractures, which indicates that fractures have a smaller effect on diffusion.

As for the results of physical simulation experiments, the diffusion experimental results under different schemes are shown in Fig. 11. Compared with the diffusion in crude oil, the diffusion path of hydrocarbon gas in the core is more complex, which results in greater diffusion and mass transfer resistance, leading to a smaller diffusion coefficient. The higher the pressure, the greater the density of gas molecules, and the greater the probability of intermolecular collision, which intensifies the thermal movement of molecules and is conducive to the diffusion and mass transfer of gas. In saturated oil cores, the lower the permeability, the longer the gas diffusion path. Gas molecules are more likely to collide with the pore wall, and the momentum loss of gas molecules after adsorption is not conducive to gas diffusion. Diffusion in fractured rock core mainly includes two processes, namely, the gas convection process in the early fracture and the diffusion process in the late matrix. This overall diffusion effect is not different from that in the core without fractures.

3.2 Influence of diffusion coefficient on hydrocarbon gas injection

The simulation results (Fig. 12) show that pressure and permeability have a great impact on the development effect of gas flooding, and the diffusion coefficient has a certain impact on the recovery, production gas oil ratio; in the range of 0.1∼10 times of diffusion coefficient, the influence of hydrocarbon gas diffusion coefficient is small. Oil and gas seepage plays a leading role in the process of gas flooding, and the influence of diffusion is not obvious.

As shown in Fig. 12(a), gas flooding recovery first decreases and then increases with the elevation of gas injection pressure. This is because the gas injection pressure is high, which easily causes gas channeling, resulting in lower recovery and higher production gas oil ratio. With the further increase in the gas injection pressure, the pressure gradient between the gas channeling channel and the nearby matrix is increased, which makes the gas diffuse from the gas channeling channel to the nearby matrix crude oil, thus expanding the sweep volume and increasing the production range of crude oil. As a result, the recovery factor is increased, and the rising rate of gas oil ratio is slowed down.

Fig. 12(b) indicates that the greater the permeability of the reservoir, the better the connectivity of pore channels and the stronger the flow capacity of crude oil, which leads to a faster speed of gas displacing crude oil under the same gas volume. With the increase in permeability, the production gas oil ratio decreases and the crude oil production increases, which leads

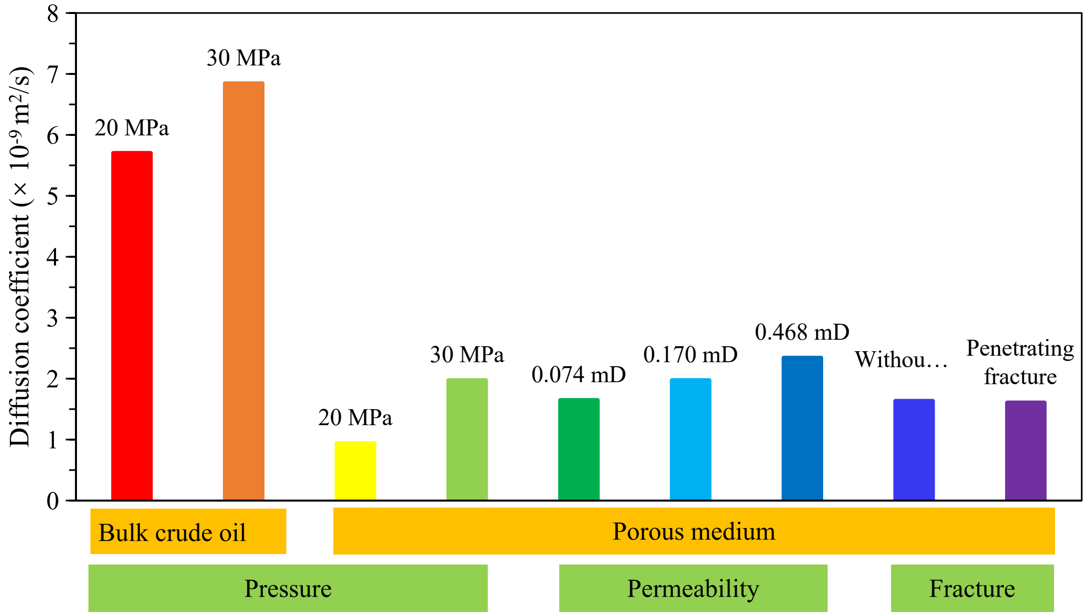

Fig. 11. Comparison histogram of hydrocarbon gas diffusion coefficient under different conditions.

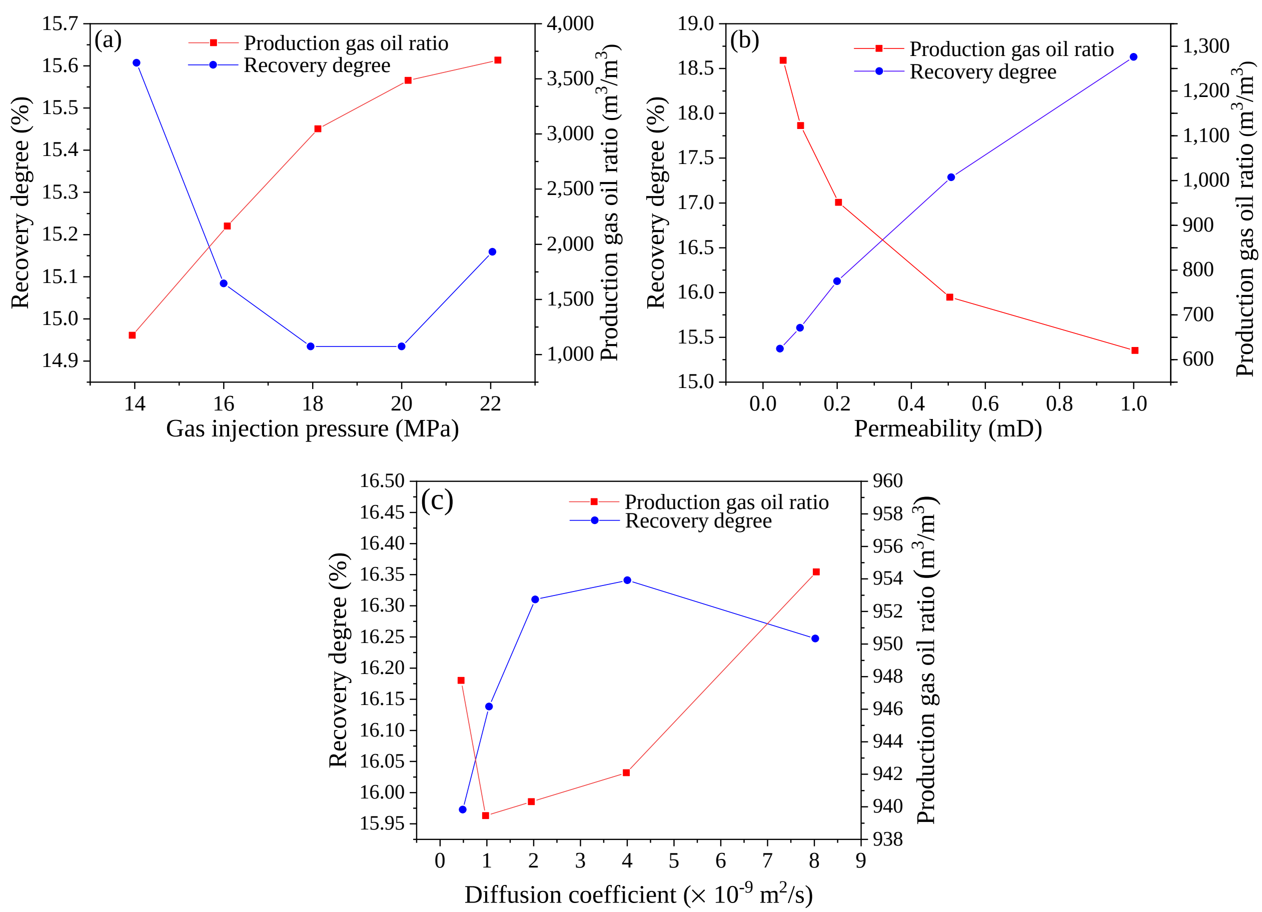

Fig. 12. Influence of different factors on hydrocarbon gas flooding. (a) Influence of gas injection pressure, (b) influence of permeability, (c) influence of diffusion coefficient.

to the recovery factor gradually rising. With the increase in the diffusion coefficient, the ability of gas molecules to enter deep pores becomes stronger (Fig. 12(c)). The recovery factor increases slightly with the increase in the diffusion coefficient. At the same time, more gas diffuses into the crude oil of deep formation, and the production gas oil ratio enhances.

However, with the increase in the diffusion coefficient, at the front edge of gas flooding, more gas will enter the crude oil, which reduces the oil-gas interface energy and weakens the oil-gas two-phase difference. Subsequent gas drive slugs will more easily break through the oil-gas interface, resulting in gas channeling, which leads to lower oil recovery and a significant increase in the production gasoline ratio.

4. Conclusions

1) The diffusion coefficient of hydrocarbon gas in saturated oil core is obviously less than that in crude oil. Porous media will seriously affect the diffusion process of gas in crude oil, and the pore structure will restrict the diffusion trajectory of gas.
2) Fractures have little effect on the matrix diffusion coefficient, whereas they considerably affect the seepage process in early fractures. The diffusion coefficient has a positive relationship with either injection pressure or core permeability, which parameters can both contribute to accelerating the diffusion mass transfer. Fractures have a weak effect on matrix diffusion, but they considerably impact the seepage process.
3) Reservoir permeability, fracture and injection pressure have a more significant impact on the development effect of hydrocarbon gas flooding/huff and puff process, while the diffusion effect is not obvious. Diffusion is more markedly manifested in crude oil modification and formation energy supplement, and its direct effect on crude oil flow is not obvious.

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Conflict of interest

The authors declare no competing interest.

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