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Received: 22 August 2019 | Revised: 27 October 2019 | Accepted: 25 November 2019

DOI: 10.1002/ese3.578

RESEARCH ARTICLE

Energy Science & Engineering Open Access

Investigation of CO_2/N_2 injection in tight oil reservoirs with confinement effect

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Funding information
National Natural Science Foundation of China, Grant/Award Number: 51604292; China Scholarship Council, Grant/Award Number: 201806450024; the People's Livelihood Science and Technology Project of Qingdao City in China, Grant/Award Number: 17-3-3-75-nsh; Fundamental Research Funds for the Central Universities, Grant/Award Number: 17CX02014A, 18CX02160A and 18CX06009A; National Science and Technology Major Project of China, Grant/Award Number: 2017ZX05009004-002 and 2017ZX05072005-004; the Applied Fundamental Research Project Funded by Original Innovation Program of Qingdao City, Grant/Award Number: 17-1-1-29-jch

Abstract

This paper investigates the CO_2/N_2 injection process in tight oil reservoirs considering the confinement effect. To study the microscopic physical mechanisms, the confinement effect is characterized by properties shift and capillarity and introduced into the flash calculation to obtain the phase equilibrium of mixture fluids (tight oil/CO_2/N_2) in tight porous media. The results indicate that the injected nitrogen gas could effectively maintain the reservoir pressure, while it also weakens the effects of the CO_2 injection recovery mechanisms, notably diffusivity and viscosity reduction. In addition, a dual-pore tight oil reservoir model is set up to investigate the CO_2/N_2 injection with ultra-low permeability and hydraulic fracturing. The basic CO_2 injection parameters are optimized by the orthogonal method. Based on CO_2 injection process, three injection schemes of CO_2/N_2 injection, which are mixed-gas injection, CO_2-alternating-N_2 (CAN) injection, and N_2-alternating-CO_2 (NAC) injection, were investigated and a comparative analysis was made for the pressure distribution, CO_2 mole fraction distribution, and cumulative oil production. Based on this analysis, the CAN injection process proved to be the best injection scheme. A parametric analysis further suggested that the nitrogen gas injection rate was the most important factor. Besides, the effect of gravity drainage, reservoir permeability, nature fractures, and permeability heterogeneity on the oil production of CAN injection process were also investigated in detail. The results show that tight oil reservoir with better vertical connectivity, poor fracture growth, and higher heterogeneity is more favorable for the CO_2/N_2 injection process.

KEYWORDS

CO_2-alternating N_2 injection, confinement effect, diffusivity, recovery mechanisms, tight oil reservoirs

1 | INTRODUCTION

With the increasing energy consumption and the decline of conventional oil production, the tight oil is another new unconventional resource after the shale gas.[1] It is praised as new "black gold" by the petroleum industry.[2-5] As Figure 1 shows, future growth in US crude oil production is projected to be driven by the development of tight oil with the worldwide decline of conventional oil production, and tight oil production will generally increase through the early 2040s when it

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will surpass 8.2 million barrels per day (b/d), accounting for nearly 70% of total US production.[6] In contrast to conventional reservoirs, the tight oil reservoirs are rich in nano-millimeters pores which lead to ultra-low permeability and very low primary recovery (less than 15%).[3] The tiny pore throats with confinement effect prevent fluid flow from reservoir matrix to natural/hydraulical fractures; as a result, the tight oil production rate would sharply decline.[3,7,8] Thus, improving tight oil production has become an urgent issue for the development of tight oil resources.

The key dominant mechanisms for the primary recovery are depressurization and solution gas drive.[9] Increasing and maintaining reservoir pressure are the effective development methods to explore tight oil reservoirs. Water injection has achieved great success in conventional oil reservoirs, but it is very challenging to apply in tight oil reservoirs because of its low injectivity and sweep efficiency. As shown in many studies,[8] the tight oil recovery due to water flooding has been very low even with advanced technology, such as horizontal drilling technology and multi-stage hydraulic fracturing technology, because they contribute to rapid depletion of the reservoir pressure. In view of such characteristics of tight reservoirs and problem with developing such reservoirs, gas injection is regarded as the most effective development method.

CO_2 injection is among the widely applied enhanced oil recovery (EOR) methods worldwide, and it has been successfully applied in conventional reservoirs.[10-13] More than 130 CO_2 injection projects are operational around the world,[8] and they have helped identify its key mechanisms, which are (a) oil viscosity reduction; (b) oil swelling due to CO_2 solution; (c) vaporization and extraction of lighter hydrocarbon component; (d) dissolved gas drive aided by gravity drainage; (e) reduction in two-phase interfacial tensions to achieve miscible; and (f) permeability improvement by acidification effect.[8,14] Therefore, CO_2 offers better injectivity to the rock matrix than the injected water, and it is more advantageous than other gases such as nitrogen gas. This makes CO_2 the best candidate for improving the tight oil recovery.[2,15-18] Several studies report that it can achieve an incremental oil recovery in the range of 5%-20% in the Bakken and Eagle ford reservoirs using the huff-n-puff gas process.[19-23] However, some studies also indicate that CO_2 injection does have several drawbacks,[24,25] including the rapid decline of oil production. Some have reported that the reservoir pressure during production cycle sharply drops after the first cycle with linear depletion to the minimum pressure.[24] Therefore, such drawbacks need to be addressed to improve the efficiency of CO_2 injection process.

Unlike CO_2 EOR, N_2 injection has not been widely applied because of the disadvantage of nitrogen's physicochemical properties. Nitrogen gas is relatively difficult to dissolve in crude oil; as a result, the injected nitrogen does not usually offer the benefits of reduction in the oil viscosity and the interfacial tension to lower the capillary trapping effect. Because of its poor solubility in the oil, the positive effect of oil swelling due to N_2 dissolution is minimal. While nitrogen gas has good elastic energy during the flooding to maintain the reservoir pressure[1,26-30] and has other advantages, such as its abundance in atmosphere, relatively low-cost and well-established harnessing/capture technology, and its noncorrosive property.[31] This makes nitrogen gas another significant gas candidate to improve tight oil reservoirs.

Siregar et al[30,32] studied the oil recovery with nitrogen injection by laboratory experiments, and the results show the N_2 injection could not lead higher oil recovery. While, other researchers point that the oil could be produced with a high and stable production rate under the N_2 flooding.[33] Joslin et al[34] have studied various EOR techniques, and the results show that N_2 flooding is the most effective method via pressure maintenance when the permeability value is lower than 0.03 mD. Although several studies have been carried out to investigate the efficiency of N_2 gas injection on tight oil reservoirs, they did not systematically and mechanistically address the feasibility of CO_2/N_2 injection and comprehensively show microphysical mechanisms in tight oil reservoirs.

This research attempt to investigate the recovery mechanisms of N_2 injection assisted CO_2 EOR in tight oil reservoir and the feasibility of CO_2/N_2 EOR, which have not been studied systematically in previous research. To discover the microscopic mechanisms of injected N_2, the confinement effect expressed by properties shift and capillarity would be introduced into the flash calculation to study the phase equilibrium state of confined fluids in tight porous media. The goal of this paper is to determine the injection scheme that is most appropriate for CO_2/N_2 injection. Besides, the tight oil reservoir types suitable for the CO_2/N_2 injection process would be investigated based on a parametric analysis.

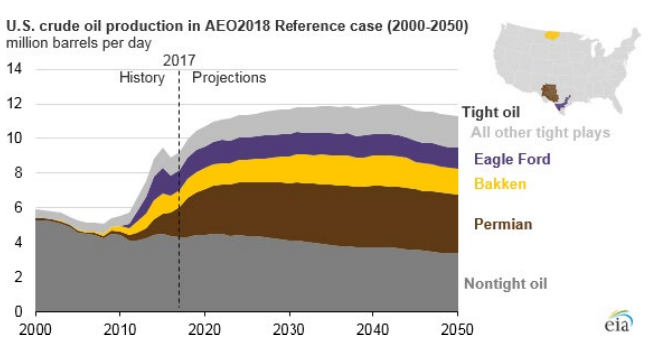

FIGURE 1 Tight oil production in North America (Source: US EIA, 2018)

2 | MICROSCOPIC PHYSICAL MECHANISMS OF NITROGEN GAS

The fluids in tight reservoirs are under the confinement effect, and hence, the phase behaviors and phase equilibrium state are different from those in conventional reservoirs. To study the microscopic physical mechanisms of nitrogen gas, the properties shift and capillarity, which are expressed by modified Soave-Redlich-Kwong (SRK) equation of state (EOS) and Young-Laplace equation, respectively, are introduced into the flash calculation in tight porous media. In this phase of our study, we assume that the mechanisms of desorption and adsorption are negligible in tight rocks and the effect of the water phase could be neglected in the tight porous media; rather, we focus on the phase equilibria in nano-pores without regard for the impact of stress-sensitive aspects.

2.1 | Flash calculation with confinement effect

For bulk fluids such as those in PVT cell, the effect of pore wall could be ignored, and the physical properties could be obtained by the classical EOS (eg, Van der Waals EOS, SRK EOS) which is widely used to study the bulk fluids. In conventional reservoirs, the fluid PVT properties are controlled by the molecular collision similar to the bulk fluid. However, fluid properties in tight porous media such as PVT properties are not only governed by fluid molecular interaction but also influenced by the interaction between fluid molecules and pore wall. The effect of tiny pores on fluids properties is defined as confinement effect, and the fluids in tight porous media are referred to as confined fluids. The state of confined fluids in tight porous media should be modified by the molecular-wall collision factor. In this study, the modified SRK EOS is used for the confined fluids, which could be expressed by:

$$P=\frac{RT}{V_m-b}-\frac{a}{V_m\left(V_m+b\right)}+\frac{c}{V_m\left(V_m+b\right)} \tag{1}$$

The third term on the right of this equation represents the fluid molecular-wall interactions proposed by Derouane.[35-37] Besides, the capillary pressure caused by tiny pore size also should be considered, which could be obtained by:

$$P_{cap}=P_V-P_L \tag{2}$$

The crude oil is identified as the wetting phase. Hence, vapor phase is the nonwetting phase, and P_{cap} is positive in this study. The capillary pressure is calculated by Young-Laplace equation:

$$P_{cap}=\frac{2\sigma\cos\theta}{r} \tag{3}$$

The components of vapor phase and liquid phase could be calculated by the following equations: Mass balance equations and Rachford-Rice equation are applied to study the phase behavior of confined fluids.

$$\begin{aligned}
&\sum_{i=1}^{N_c}x_i=\sum_{i=1}^{N_c}y_i=1\\
&Fz_i=x_iL+y_iV\\
&\sum_{i=1}^{N_c}\frac{\left(K_c^i-1\right)z_i}{1+(V/F)\left(K_c^i-1\right)}=0\\
&i=1,\ldots,N_c
\end{aligned} \tag{4}$$

For N_c component system, the fugacity of every component should be satisfied when phase equilibrium is achieved, which is expressed by:

$$f_i^L(T,P_L,x_i)=f_i^V(T,P_V,y_i) \tag{5}$$

The fugacity could be obtained by fugacity coefficient, and the relationship is:

$$\varphi_i^L=\frac{f_i^L}{P_L},\ \varphi_i^V=\frac{f_i^V}{P_V} \tag{6}$$

where φ_i^L, φ_i^V means the fugacity coefficient of component i, respectively, in liquid and vapor phases, which could be calculated using the modified SRK EOS by:

$$\begin{aligned}
\ln\left(\varphi_i^L\right)&=\frac{b_i}{b_m}\left(Z_L-1\right)-\ln\left(Z_L-\frac{b_mP_L}{RT}\right)-\frac{a_m}{b_mRT}\left[\frac{2\sum_{j=1}^{n}x_ja_{ij}}{a_m}-\frac{b_i}{b_m}\right]\ln\left(1+\frac{b_mP_L}{Z_LRT}\right)\\
\ln\left(\varphi_i^V\right)&=\frac{b_i}{b_m}\left(Z_V-1\right)-\ln\left(Z_V-\frac{b_mP_V}{RT}\right)-\frac{a_m}{b_mRT}\left[\frac{2\sum_{j=1}^{n}y_ja_{ij}}{a_m}-\frac{b_i}{b_m}\right]\ln\left(1+\frac{b_mP_V}{Z_VRT}\right)
\end{aligned} \tag{7}$$

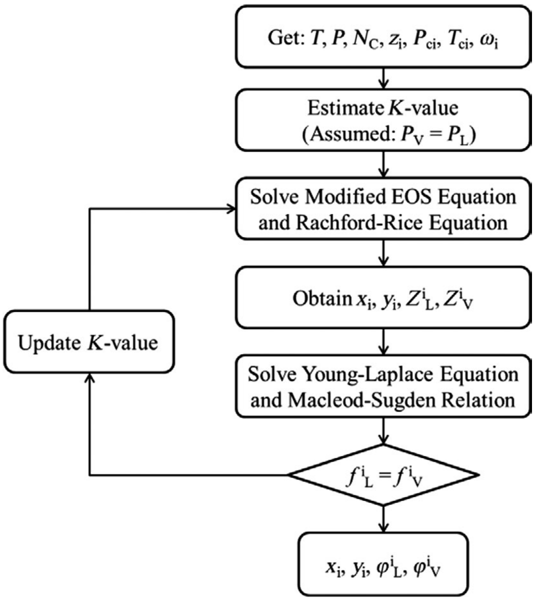

FIGURE 2 Cyclic iteration method to flash calculation of confined fluids in tight porous media

Hence, the vapor-liquid phase equilibrium in nano-porous media could be obtained using the aforementioned equations. Then, the cyclic iteration method is used for flash calculation to obtain the component content change in each phase and this is depicted through Figure 2. To estimate the K-value, we can use Wilson's equation to obtain the initial value[38]:

$$K = \frac{P_c}{P} \exp\left[5.373\,(1+\omega)\left(1-\frac{T_c}{T}\right)\right] \tag{8}$$

To validate this phase equilibrium calculation model, the calculated K-value of bulk fluids and confined fluids under certain conditions would be compared with the experimental measurement data, which has shown in Table 1.[37-40] As is shown, the biggest relative deviation is 3.73%, which means this developed model could effectively predict the vapor-liquid phase equilibrium of CO_2/hydrocarbon systems in tight porous media.

2.2 | Phase equilibrium of tight oil/CO_2/N_2

The Middle Bakken has provided a good example of tight oil production which would be used to simulate the CO_2 flooding.[7,9,22] The properties data of oil components have been listed in Table 2. The other physiochemical properties of tight oil could be found in references.[6,8]

The phase equilibrium state in tight porous media could be obtained by the flash calculation (cf. Figure 2). The system temperature is 360 K. The matrix feature size of nano-pore is 50 nm, which means the permeability is approximately 0.01 mD according to the Carman-Kozeny equation. Two cases of mixture fluids are studied in this part: oil/CO_2 with ratio of 80%:20% and oil/CO_2/N_2 with ratio of 40%:10%:50%. These two cases have the same ratio of content of CO_2 and tight oil. The phase equilibrium states have shown in Figures 3 and 4.

The Figure 3 shows the vapor pressure and capillary pressure of those two cases under different conditions (oil phase pressures are 8 MPa, 10 MPa, 12 MPa, 15 MPa, respectively). As shown in Figure 3, the vapor pressure would increase with the injection of nitrogen gas, and the same trend would be for the capillary pressure. The insolubility of nitrogen in tight oil is the primary reason for the increased pressure. The capillary pressure of oil/CO_2 case is equal to zero when the pressure is 15 MPa, which means that all CO_2 dissolves into tight oil. The capillary pressure of oil/CO_2/N_2 case is not equal to zero under same condition, which implies that the vapor phase still exists. Thus, the injected nitrogen gas could enhance the pressure in a single pore throat, which is conducive to maintaining the reservoir pressure. Besides, the existing vapor phase would lead to the reduction the CO_2 solubility in tight oil.

Based on the phase equilibrium state, the ratios of CO_2 molar number in vapor phase to CO_2 molar number in liquid

TABLE 1 The results of comparison between experimental results and model prediction[37-40]

Test no.	Conditions	Component	Molar fraction, %	Experimental data	Simulation results	Relative deviation, %
No. 1	213.9 K 5.44 MPa	C1	84.50	1.156	1.1438	1.05
		C2	14.76	0.448	0.4436	0.98
		C3	0.74	0.203	0.2013	0.84
No. 2	344.8 K 0.426 MPa 800 nm	iC4	61.89	2.652	2.5810	2.68
		nC4	18.11	1.885	1.8146	3.73
		C8	20.00	0.0524	0.0530	1.15
No. 3	345 K 0.426 MPa 100 nm	iC4	15.47	13.187	12.8085	2.87
		nC4	4.53	8.995	8.6729	3.58
		nC5	80	0.202	0.1967	2.62

TABLE 2 Tight oil composition from Middle Bakken

Component	CO_2	N_2	CH_4	C_2-C_4	C_5-C_7	C_8-C_9	C_{10+}
z	0.00	0.00	0.25	0.22	0.20	0.13	0.20
P_c, atm	72.80	33.50	45.40	42.54	33.76	30.91	21.58
T_c, K	304.20	126.20	190.60	363.30	511.56	579.34	788.74
V_c, L/mol	0.0940	0.0895	0.0990	0.1970	0.3338	0.4062	0.9208
M, g/mol	44.01	28.01	16.04	42.82	83.74	105.91	200.00
ω	0.2250	0.0400	0.0080	0.1432	0.2474	0.2861	0.6869
$[P]$	78.0	41.0	77.0	145.2	250.0	306.0	686.3
k_{ij}							
CO_2	0	−0.0200	0.1030	0.1327	0.1413	0.1500	0.1500
N_2	−0.0200	0	0.0310	0.0784	0.1113	0.1200	0.1200
CH_4	0.1030	0.0310	0	0.0078	0.0242	0.0324	0.0779
C_2-C_4	0.1327	0.0784	0.0078	0	0.0046	0.0087	0.0384
C_5-C_7	0.1413	0.1113	0.0242	0.0046	0	0.0006	0.0169
C_8-C_9	0.1500	0.1200	0.0324	0.0087	0.0006	0	0.0111
C_{10+}	0.1500	0.1200	0.0779	0.0384	0.0169	0.0111	0

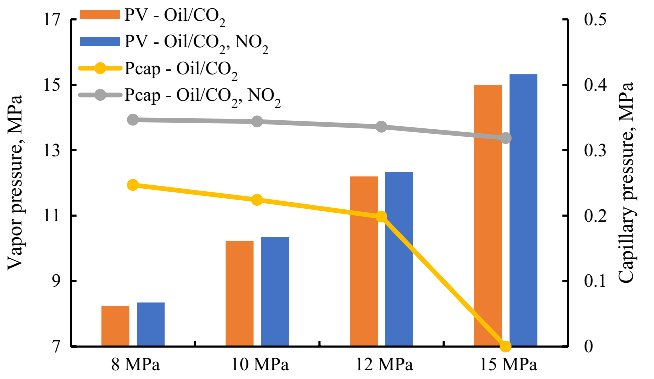

FIGURE 3 Vapor pressure and capillary pressure under different oil phase pressure condition (8 MPa, 10 MPa, 12 MPa, 15 MPa) in oil/CO_2 case and oil/CO_2/N_2 case

phase for those two cases have shown in Figure 4. The CO_2 molar proportion in the vapor phase is greatly increased with the injected nitrogen gas, and correspondingly, the CO_2 content in tight oil is reduced. Thus, the injected nitrogen gas will weaken the CO_2 recovery mechanisms such as viscosity reduction and oil swelling. Due to the different fluidity of gas phase and liquid phase, the CO_2 spreading area would be influenced and this will be investigated in the next phase of this study. Besides, the ratio of CO_2 content would be equal to zero when the pressure is above to 12 MPa in oil/CO_2 mixed fluid system, while it remains at a high value in oil/CO_2/N_2 mixed fluid system. Based on this, it can be concluded that the injected nitrogen gas had obviously increased the gas saturation in tight porous media.

Besides, the molecular diffusion is a mass transfer phenomenon, which is an important part of fluid flow during CO_2 injection process, and the sweep area of injected CO_2 would be extended by diffusion flux.[41,42] An empirical correlation proposed by Wilke and Chang was used to estimate the diffusion coefficient in mono-phase fluid, which is the most general and best-know equation.[43-45] This equation is expressed by:

$$D_{ik}=\frac{7.4\times10^{-8}\left(M'_{ik}\right)^{1/2}T}{\mu_k V_{bi}^{0.6}}$$
$$M'_{ik}=\frac{\sum_{j\neq i}x_{jk}M_j}{1-x_{ik}} \tag{9}$$
$$V_{bi}=0.285V_c^{1.048}$$

where, the subscript k means the fluid phase (ie, liquid phase and vapor phase). Based on the phase equilibrium state and Equation (9), the CO_2 diffusion coefficients in the respective liquid and vapor phases under different fluid systems were obtained and are shown in Figure 5. In general, the diffusion coefficient decreases with the increase in pressure. Furthermore, the CO_2 diffusion coefficient would decrease because of the nitrogen gas.

The viscosity is an important parameter to reflect the fluid fluidity, and the low viscosity is beneficial to the fluids flow. Based on the Jossi-Stiel-Thodos (J-S-T) correlations proposed by Yoon-Thodos and Herning-Zipperer using the corresponding mixing rule,[46,47] the viscosities of liquid phase and vapor phase were calculated under the phase equilibrium state as shown in Figure 6. The injected nitrogen gas has great influence on the fluid viscosities; for, the viscosity of liquid phase fluid increases while that of vapor phase fluid decreases. Besides, the liquid viscosity decreases with the increase in pressure without nitrogen gas in nano-pore while it increases when the nitrogen gas is

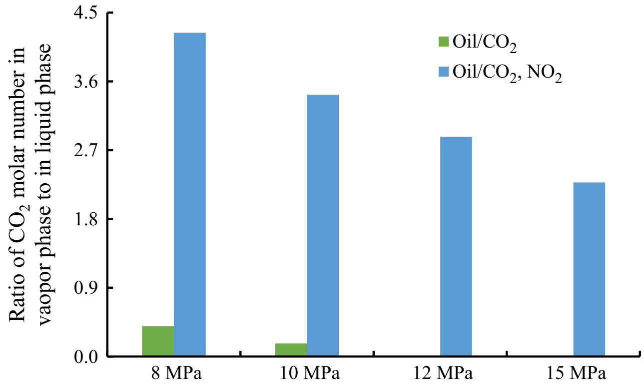

FIGURE 4 Ratios of CO_2 molar number in vapor phase to molar number in liquid phase under different oil phase pressure conditions (8 MPa, 10 MPa, 12 MPa, 15 MPa) in oil/CO_2 case and oil/CO_2/N_2 case

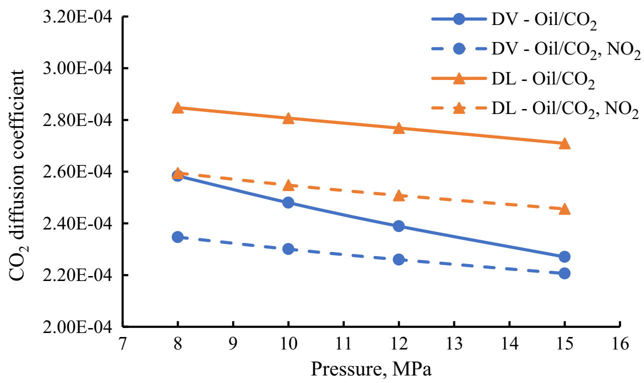

FIGURE 5 CO_2 diffusion coefficient in vapor phase and in liquid phase under different pressure conditions (the lines remarked by circle show the diffusion coefficient in vapor phase, while the lines remarked by triangle show the diffusion coefficient in liquid phase; the solid lines show the oil/CO_2 fluid system, while the dotted lines show the oil/CO_2/N_2 fluid system)

present, which means that the injected nitrogen is not conducive to viscosity reduction in tight oil. Thus, the injected nitrogen gas would increase the fluidity of vapor phase in tight porous media.

The phase equilibrium state would be shifted because of the nitrogen gas injection, which will cause the increase in capillary pressure, the reduction of CO_2 content in tight oil, the enlargement of gas saturation, the decrease in CO_2 diffusion coefficient, the higher liquid phase viscosity, and the lower vapor phase viscosity. The injected nitrogen gas could effectively maintain the reservoir pressure; meanwhile, it also weakens the CO_2 recovery mechanisms. In the next section, the feasibility and development characteristics of CO_2/N_2 EOR in tight oil reservoirs would be investigated based on this phase equilibrium shift and fluid flow in porous media.

3 | SIMULATION MODEL OF CO_2/N_2 INJECTION PROCESS

To study the feasibility of CO_2/N_2 injection in tight oil reservoirs, the GEM simulator of Computer Modeling Group's (CMG, 2018) is used to model the process of tight oil reservoir development. As published in the article,[7,9,22,48] the basic tight oil reservoir model from Middle Bakken with multi-stage hydraulic fractures which were history matched reasonably well by incorporating the Middle Bakken production data was used to study the development of CO_2/N_2 injection (see Figure 7). For a single stage of horizontal well with multi-stage fractures, the dimensions of this reservoir are 340 ft × 1300 ft × 40 ft (length × width × thickness), and the number of grids is 17 × 65 × 1.[9] One horizontal well with four hydraulic fractures is modeled using dual-pore model to mimic fracture properties. The half-length of each hydraulic fracture is set to 210 ft, and the spacing between adjacent fractures is 80 ft.[9] The basic parameters of matrix and fracture have shown in Table 3.[9] The rock and fluid properties are necessary to simulate the tight oil reservoir. The hydrocarbon compositions of Middle Bakken have been listed in Table 2, and relative permeability value of water/oil and gas/oil is shown in Figure 8.

3.1 | CO_2 huff-n-puff process

CO_2 huff-n-puff injection process is considered as the most effective injection scheme with ultra-low permeability,[18] which could utilize the large surface area of the hydraulic and natural fractures to transfer the CO_2 into deeper reservoir and enhance oil recovery. In this case, The CO_2 injection process will be following a 5-year natural depletion production period. The inject well would be constrained by the maximum bottom hole pressure of 8000 psi and the maximum injection rate of 500 MSCF/d. The injection well would be shut in after 3 months following with the 3 months of soaking time, and then, the well will restart production to continue. It should be pointed out that the CO_2 diffusion factor is considered into the reservoir development simulation, which is valued as 0.00025.

To optimize the injection well schedule, the orthogonal method is used to study the key parameters of CO_2 injection process, and the test design is shown in Table 4. The effect of three parameters are examined in this part: injection rate (200 MSCF/d, 500 MSCF/d, 1000 MSCF/d), injection time (3 months, 6 months, 9 months), and soaking time (3 months, 6 months, 9 months). As shown in Table 4, nine testes are designed and simulated cumulative oil production. In Table 4, the values of I, II, and III are equal

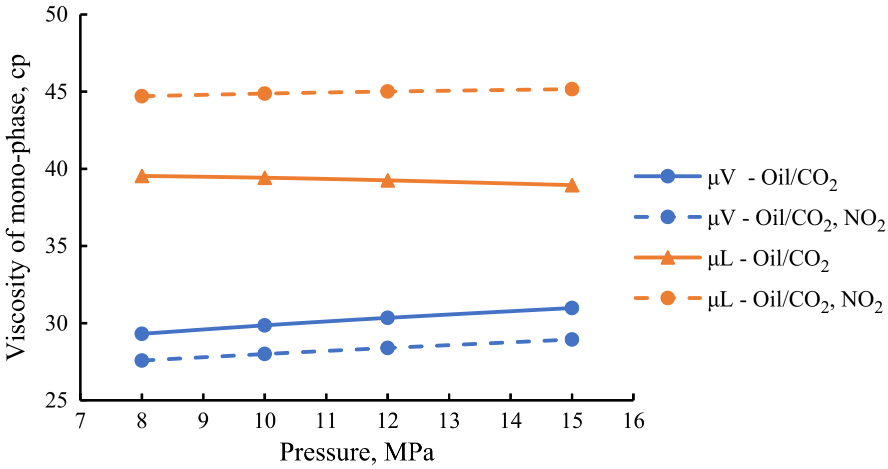

FIGURE 6 The viscosity of mono-phase under different pressure conditions ("μV" means the viscosity of vapor phase, and "μL" m0065ans the viscosity of liquid phase under phase equilibria state)

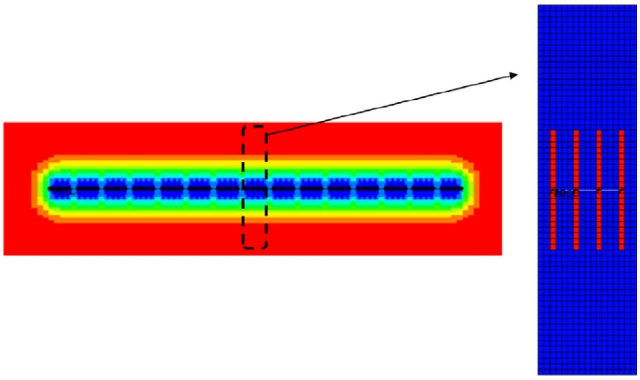

FIGURE 7 The basic tight reservoir model from Middle Bakken with a single stage fracture of horizontal well

TABLE 3 Basic parameters data of matrix and fracture in basic reservoir

Parameter	Value	Unit
Reservoir dimension	340 × 1300 × 40	ft × ft × ft
Grid blocks	17 × 65 × 1	–
Refined grid	7 × 7 × 1	–
Initial reservoir pressure	8000	psi
Reservoir temperature	240	°F
Matrix permeability	0.01	mD
Matrix porosity	0.07	–
Fracture conductivity	50	mD-ft
Fracture half-length	210	ft
Fracture height	40	ft
Initial water saturation	0.25	–
Total compressibility	1×10^6	psi^{-1}

to the sum of cumulative oil productions with the same parameter value of the same parameter among those tests; for example, II-2 equals to the sum of cumulative oil productions of Test #2, Test #5, and Test #8. The values of K_1, K_2, and K_3 are the mean values of cumulative oil production and could be obtained by:

$$K_i = I_i/3, i = 1,2,3 \tag{10}$$

which express the average oil recovery factor under an influence factor i. Moreover, R is the maximum difference value among K_i, which means the effect of factor on the cumulative oil production.

As shown in Table 4, the highest cumulative oil production was obtained in Test #2, and this could be chosen to set the cyclic CO_2 injection process parameters. The most influential parameter is the injection rate following with the injection time and soaking time. Besides, the injection rate is negatively correlated with recovery factor, and this result agrees with the core-flood experiments designed by Karim et al[49] who proposed that oil recovery efficiencies of light oil were poorer at very high injection rates.

3.2 | CO_2/N_2 injection scheme

Using N_2 as chasing gas has shown great potential to improve the development of CO_2-based EOR processes.[49-51] The major mechanism of N_2 injection is to maintain the reservoir pressure, which has shown in part 2. Three injection schemes including mixture gas injection, CO_2-alternating N_2 (CAN) injection, and N_2-alternating CO_2 (NAC) injection were investigated in this study under similar conditions. CO_2 slug parameters are same as those in the CO_2 huff-n-puff process, that is, the CO_2 injection rate is 200 MSCF/d and the soaking time is 6 months. And, the N_2 injection rate is also 200 MSCF/d and the inject well is constrained by the maximum bottom hole pressure of 8000 psi. The detail of well schedules from primary production to CO_2/N_2 injection is illustrated in Table 5.

As shown in Figure 9, nitrogen gas injection would effectively increase reservoir pressure and improve pressure distribution, which is consistent with the simulation results of confined

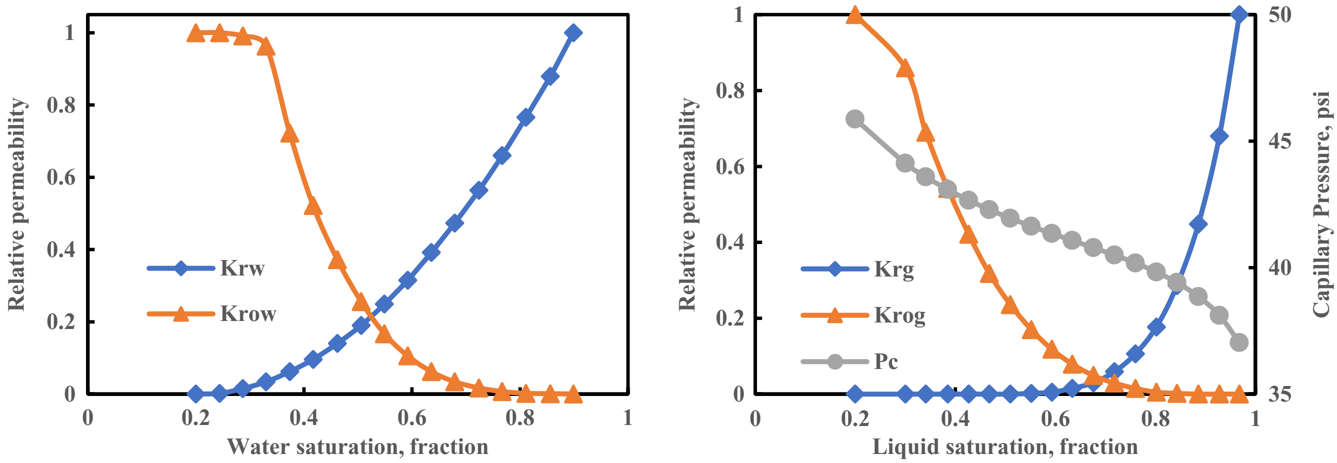

FIGURE 8 Relative permeability curves[7,48]

TABLE 4 The simulation results using orthogonal method for CO_2 injection process

	Injection rate	Injection time	Soaking time	Other factor	
Test no.	**1**	**2**	**3**	**4**	**Cum. oil prod. (stb)**
1	200	3	3	1	32 932.7
2	200	6	6	2	33 431.3
3	200	9	9	3	33 375.4
4	500	3	6	3	33 173.5
5	500	6	9	1	33 082.9
6	500	9	3	2	33 178.9
7	1000	3	9	2	32 921.5
8	1000	6	3	3	33 004.8
9	1000	9	6	1	32 841.4
I	99 739.4	99 027.7	99 116.4	98 857.0	
II	99 435.3	99 519.0	99 446.2	99 531.7	
III	98 767.7	99 395.7	99 379.8	99 553.7	
K_1	33 246.5	33 009.2	33 038.8	32 952.3	
K_2	33 145.1	33 173.0	33 148.7	33 177.2	
K_3	32 922.6	33 131.9	33 126.6	33 184.6	
R	323.9	163.8	109.9	232.2	
Sequence factor	Injection rate, injection time, soaking time				

TABLE 5 Well schedule of CO_2/N_2 injection process

				4		5			
Year/month	**1**	**2**	**3**	**6 mo**	**6 mo**	**6 mo**	**6 mo**	**… …**	**30**
CAN	Primary production			CO_2 injection	N_2 injection	Soaking	Production		
Mixture gas	Primary production			Mixture gas injection		Soaking	Production		
NAC	Primary production			N_2 injection	CO_2 injection	Soaking	Production		

fluids phase equilibrium calculation. The smaller solubility of injected gas into tight oil could cause the increase in gas phase saturation, which could maintain the reservoir pressure. The higher matrix pressure in the near fracture zone is contributed to the pressure transmission to farther area, which could be obtained from the pressure distribution of boundary region.

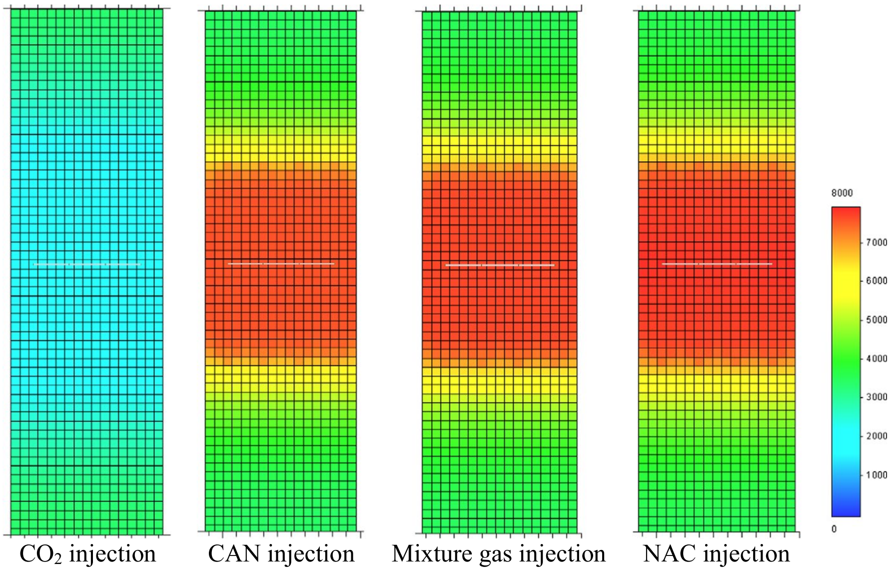

FIGURE 9 The pressure distribution before well production

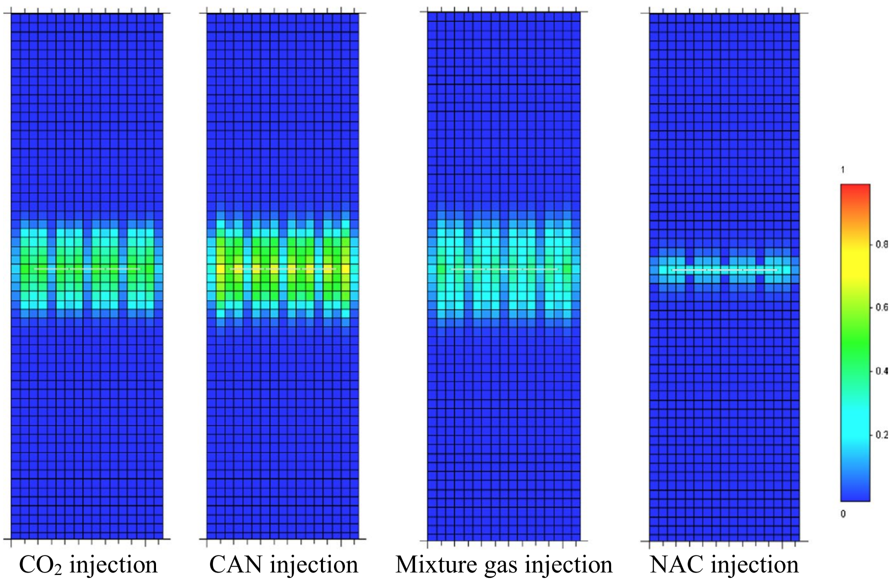

FIGURE 10 The CO_2 mole fraction distribution before well production

The NAC injection process could build up the highest reservoir pressure and the best pressure distribution, while mixture gas injection process has almost similar pressure distribution with CAN injecting process.

The insolubility and nonliquefaction of nitrogen gas in crude oil should be responsible for this difference. The injected nitrogen gas would find it easier to seep in tight porous media than the dissolved carbon dioxide. The partial pressure of carbon dioxide would decrease in gas phase with the nitrogen gas, and partially dissolved carbon dioxide would be vaporized with light hydrocarbon component, which benefits the oil recovery. Besides, the gasification of carbon dioxide and light hydrocarbon will lead to the increase in gas saturation, and the rich gas would spread to further areas. And this is the reason why the pressure distribution with N_2 injection is better than with the pure CO_2 injection. No dissolved carbon dioxide in reservoir during NAC injection process would cause the diffusion of injected nitrogen gas which will lead to wider high pressure distribution, and the followed injected carbon dioxide would difficult to sweep which could be proved by CO_2 mole fraction distribution as shown in Figure 10.

The mole fraction distributions of carbon dioxide have shown that the poor CO_2 sweep area by NAC injection (see Figure 10). As all reach the constraint conditions (8000 psi of bottom hole pressure), the total mass of injected CO_2 of CAN injection process is equal to CO_2 injection process, while the mixture gas injection process has smaller CO_2 injection volume and the NAC injection process has minimum CO_2 injection volume. As shown in Figure 10, the injected carbon dioxide would be enriched in the near well and it will have difficult to diffuse due to ultra-low permeability. CO_2 would, therefore, diffuse farther in due to subsequent nitrogen injection, but its partial pressure acts against the dissolution of carbon dioxide and the extraction of lighter hydrocarbon component. Besides, the area where CO_2 has spread could not be extended if the N_2 is injected before CO_2 injection. The best injection scheme should be selected by comparison of the expected cumulative oil production (see Figure 11). As shown in Figure 11, the CAN injection scheme would obtain the best oil production, while the NAC injection scheme yields the minimum oil production.

In summary, N_2-assistant injection is beneficial to CO_2 injection for tight oil recovery. The main effect of injected nitrogen gas is to maintain the reservoir pressure and to expend the swept range, which could be explained by the microscopic mechanisms simulation results of part 2. The nitrogen injection model has great effect on the tight oil production, and the CAN injection process has been proved as the optimized injection scheme.

4 | SIMULATION RESULTS

4.1 | Parameter analysis of CAN injection scheme

The CAN injection process has been proved as the best injection scheme to improve tight oil recovery, and the main function of injected nitrogen is maintaining reservoir pressure. The N_2 injection rate, N_2 injection time, and soaking time would have great effect on the oil recovery. Based on the basic model (200 MSCF/d of CO_2 and N_2 injection rate, 6 months of CO_2 and N_2 injection time, and 6 months of soaking time), the parameters are analyzed with determined other parameters (8000 psi of maximum bottom hole pressure in injection well, etc).

1. Effect of nitrogen injection rate

To address the effects of nitrogen injection rate on CAN injection process, four injection rates were respectively conducted to simulate the recovery process as shown in Figure 12, keeping the other parameters same as those in the base case. The oil recovery factor would be largest when the injection rate is 200 MSCF/d. The large injection rate will cause the increase in vapor phase pressure, which would lead to the CO_2 separation from crude oil as shown in section 2, while the smaller injection rate would not conducive to the maintenance of reservoir pressure. Thus, same as large injection rate, smaller rate is harmful to the tight oil recovery.

2. Effect of nitrogen gas injection time

Determining slug size is the most important consideration to design the development program. The gas injection time will determine the slug size under the certain injection rate. Based on the analysis, the injection rate of 200 MSCF/d is selected to study the effect of slug size. As is shown in Figure 13, four times of nitrogen gas injection have been simulated keeping the other parameters same as those in the base case.

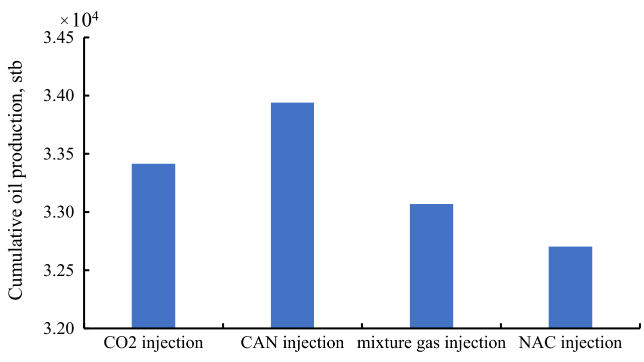

FIGURE 11 The cumulative oil production of different gas injection schemes

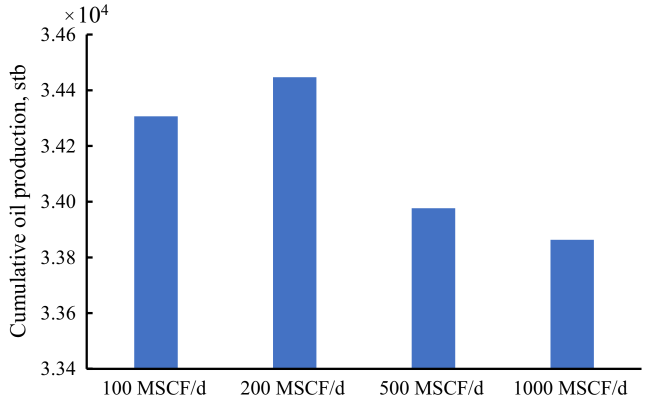

FIGURE 12 The cumulative oil production of CO_2-alternating N_2 injection process with different nitrogen gas injection rate

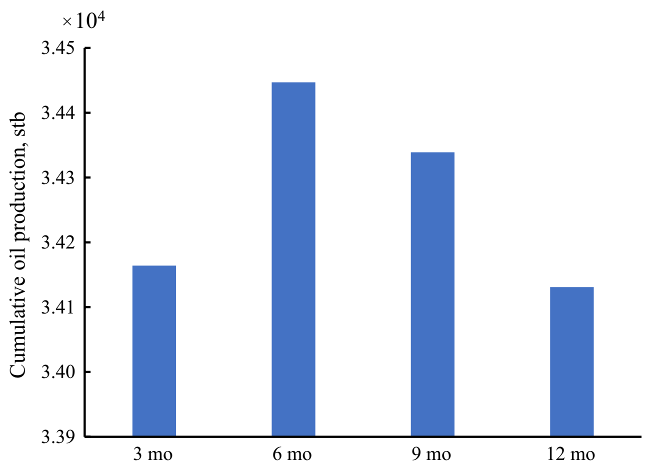

FIGURE 13 The cumulative oil production of CO_2-alternating N_2 injection process with different nitrogen gas time

The oil recovery factor would have an overall increase with the length of nitrogen injection time. The reservoir pressure will remain at high pressure under long-term injection conditions, which is beneficial to oil recovery. Besides, long-term injection would cause the large sweep area of injected CO_2, which could be suspected.

3. Effect of soaking time

Soaking time is a major operating parameter, which has direct effect on cyclic gas injection process. For the effect of soaking time, there has not been any general agreement.[50,52-54] Some researchers suggested that the soak period did not help much in improving the in-depth distribution of injected gas, while the opposite opinions were put forward on the basis of evaluations some field projects.[50] As shown in Figure 14, the gas injection scheme with short soaking time would have better oil recovery, but the short soaking time will not help much in improving the oil recovery, which is consistent with the published standpoint.

Compared with the CO_2 huff-n-puff process, the CO_2-alternating N_2 injection process with optimized parameters (200 MSCF/d of injection rate, 6 months of injection time, and 6 months of soaking time) could increase the cumulative oil production from 3.343×10^4 stb to 3.445×10^4 stb, and increase by 3.05%. Besides, by comparing the difference between the maximum and minimum of these three sets of simulations, the first influencing factor is nitrogen injection rate following with injection time and soaking time.

4.2 | Effect of gravity drainage (k_v/k_h)

Gravity drainage effect is an important recovery factor during gas injection with horizontal wells, which is a driving force. In this part, three different reservoir models with the different value of k_v/k_h are investigated to study the effect of gravity drainage. The simulation results are shown in Figure 15. As is shown, when the value of k_v/k_h is small, the cumulative oil production of CO_2 injection process is higher than the CO_2/N_2 injection process. When the vertical permeability is ultra-low and gravity drainage has less influence, the injected gases mainly transfer in horizontal area, and the injected nitrogen following with CO_2 injection could lead to the increase in viscosity of liquid phase which has proved in part 2, as the results that the nitrogen-assisted injection is adverse to tight oil recovery. The effect of gravity drainage will prominent with the increase in the k_v/k_h value, and the injected nitrogen could reduce the CO_2 leakage and maintain effective displacement in main reservoir because nitrogen gas is lighter than CO_2. Thus, the tight reservoirs with better vertical connectivity are more favorable for the CO_2/N_2 injection process.

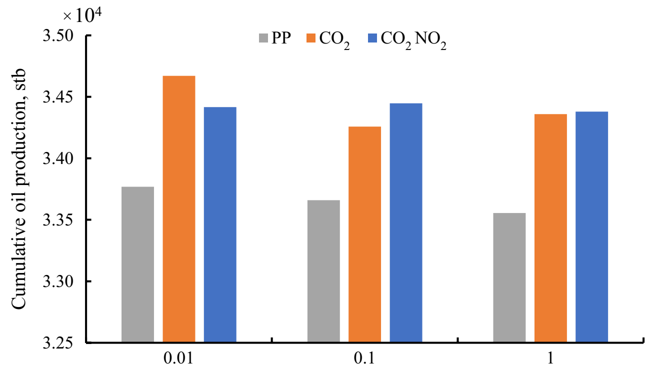

FIGURE 15 The cumulative oil production of three cases with different value of k_v/k_h ("PP" means primary production process, "CO2" means CO_2 injection process and "CO2N2" means CAN injection process)

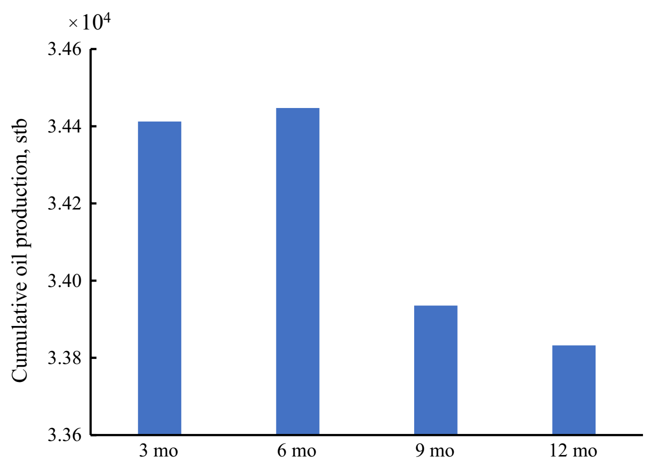

FIGURE 14 The cumulative oil production of CO_2-alternating N_2 injection process with different soaking time

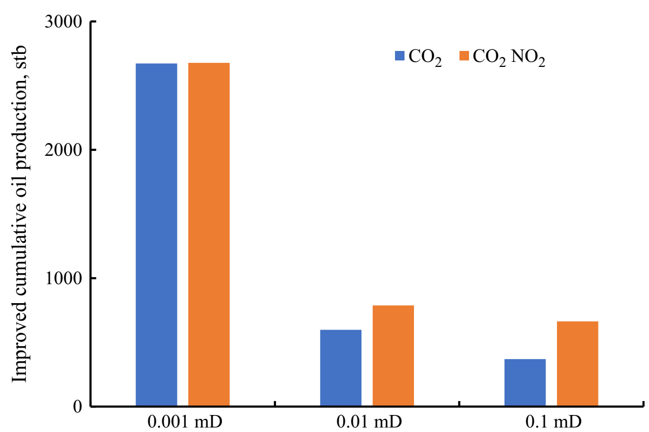

FIGURE 16 Effect of reservoir permeability on enhanced cumulative oil production of CO_2 or CO_2/N_2 injection

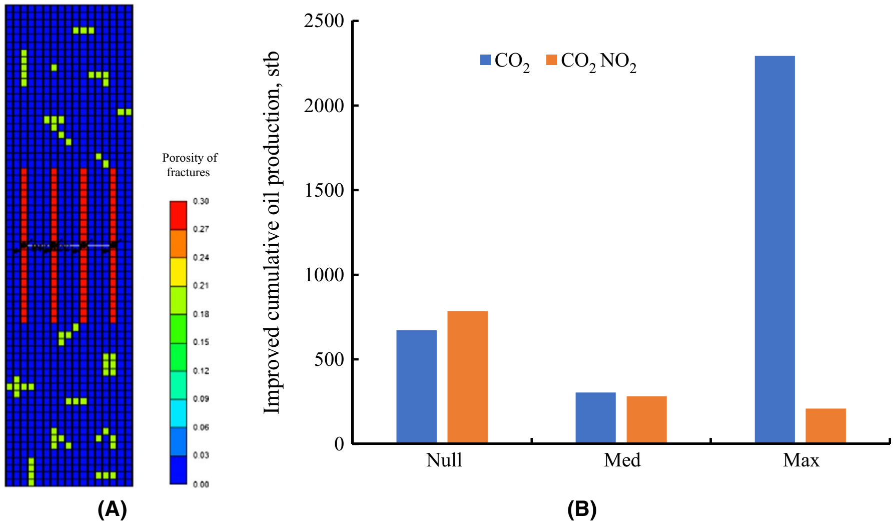

FIGURE 17 The effect of natural fractures exist: (A) natural fractures exist; (B) the improved cumulative oil production

4.3 | Effect of reservoir permeability

Typically, permeabilities for tight reservoirs are in the range of 0.001-0.1 mD. Figure 16 shows the effect of reservoir permeability on the well performance with CO_2 injection and CO_2/N_2 injection, while keeping other parameters consistent with the basic model. The simulation results show that the gas injection will effectively improve the tight oil recovery. It also can be seen that when the permeability is too small, the nitrogen-assisted injection will have less effect on the tight oil production; conversely, the CO_2/N_2 injection could obtain greater oil production than CO_2 injection process when the reservoir permeability is more than 0.01 mD. The lower the permeability, the smaller pore size; the postinjected nitrogen could not contact and dissolve with the most CO_2 at displacement front which have been injected into reservoir, and the nitrogen gas could not work effectively. Thus, the CO_2/N_2 injection is more suitable for application in tight oil reservoirs that have higher permeabilities.

4.4 | Effect of natural fractures

In real reservoirs, natural fractures are abundant in the matrix, and the complex fracture geometry has significant influence on the oil production. In this part, three cases, such as null natural fractural reservoir, general natural fractural reservoir, and fully natural fracture reservoir, are used to study the effect of natural fractures. In our study of the naturally fractured reservoir, we assumed fractures in the matrix were partially developed as shown in Figure 17A. The enhanced cumulative oil production comparison of those three cases is shown in Figure 17B. Notice that the CO_2 injection would lead to a higher oil production when the reservoir fractures are fully developed; whereas, the CO_2/N_2 injection process yields a lesser cumulative oil production than CO_2 injection process. The reason for this phenomenon is that the fluids in fracture are bulk fluids, and the injected nitrogen gas would dilute the CO_2 concentration, which will weaken the CO_2 displacement mechanisms such as solution and viscosity reduction. Beside, the reservoir with poor natural fracture development could produce more tight oil using CO_2/N_2 injection, which could be seen from Figure 17. Thus, the poor fracture growth is more favorable for the CO_2/N_2 injection.

4.5 | Effect of permeability heterogeneity

Typically, there exists heterogeneities in the reservoir permeability characteristics in the reservoirs and they have great a significant effect on the fluid flow behavior and this needs to be accounted for in a field development plan. In this part, the geo-statistical approach is used to generate stochastically multiple realizations of the permeability.[9] As shown in Figure 18, three cases of reservoir model with heterogeneous permeability, such as minimum heterogeneity, medium heterogeneity, and maximum heterogeneity, have been built to study the heterogeneity effect. The mean permeability of those three cases is 0.01 mD. The variance of permeability data is used to represent heterogeneity and is 0.001, 0.003, and 0.005 of these three cases, respectively. The cumulative oil production of three cases is shown in Figure 19. Notice that the cumulative oil production would decrease with the stronger heterogeneity. Compared with CO_2 injection, nitrogen-assisted injection appears to yield a higher oil production when the heterogeneity is high. Due to the low solubility in tight oil, the injected nitrogen gas could maintain the gas saturation and keep great mobility, as the results of that the injected

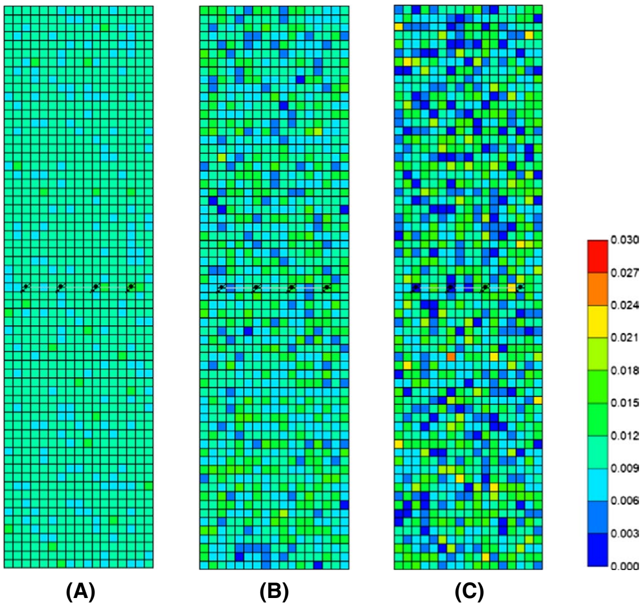

FIGURE 18 Three cases of heterogeneity in terms of permeability (the range is 0.00-0.03, the mean value is 0.01): (A) minimum heterogeneity, (B) medium heterogeneity, (C) maximum heterogeneity

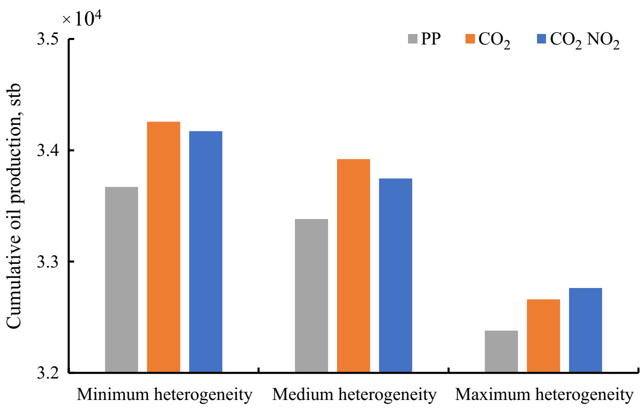

FIGURE 19 Effect of reservoir heterogeneity on comparison of tight oil production

gas could penetrate the interlayer or poor permeability reservoirs which has been verified by visualization experiments.[55] Thus, it can be concluded that the tight oil reservoirs with strong heterogeneity will have larger oil production with the CO_2/N_2 injection.

5 | CONCLUSIONS

The recovery mechanisms and feasibility of CO_2/N_2 injection in tight oil reservoir have been studied and evaluated by numerical simulation with confinement effect in this paper. The flash calculation of confined fluids in tight porous media is obtained by coupling the modified SRK EOS and capillary pressure. The phase equilibrium of tight oil/CO_2/N_2 shows the dominant mechanism of injected nitrogen gas is to maintain system pressure, while the recovery mechanisms of CO_2 injection would weaken with the nitrogen gas existence. A type Middle Bakken tight oil reservoir model was used to simulate CO_2/N_2 injection. The results indicated that the CO_2-alternating N_2 injection is the best injection scheme to obtain the best oil recovery. The parameter analysis results show that the N_2 injection rate is the primary parameter in CAN injection process. Besides, the geological characteristic parameters, such as value of k_v/k_h, reservoir permeability, nature fractures, and permeability heterogeneity, have great effect on tight oil production. Simulation results illustrated that the tight oil reservoir with greater permeability, better vertical connectivity, poor fracture growth, and higher heterogeneity is more favorable for the CO_2/N_2 injection process.

ACKNOWLEDGMENTS

The authors would like to acknowledge Computer Modeling Group Ltd. for providing the CMG software for this study. This work was supported by the National Natural Science Foundation of China (Grant 51604292), the National Science and Technology Major Project of China (2017ZX05072005-004, 2017ZX05009004-002), Fundamental Research Funds for the Central Universities (18CX06009A, 18CX02160A, 17CX02014A), the People's Livelihood Science and Technology Project of Qingdao City in China (17-3-3-75-nsh), the Applied Fundamental Research Project Funded by Original Innovation Program of Qingdao City (17-1-1-29-jch), and China Scholarship Council (CSC File No. 201806450024). Authors thank China University of Petroleum (East China), Qingdao and University of Calgary for the support and permission to present this study. The reservoir data support from the published paper for this study is also acknowledged.

NOMENCLATURE

Symbols

a	parameter in equation of state
a_m	parameter in equation of state of mixture
b	parameter in equation of state
b_i	parameter in equation of state of component i
b_m	parameter in equation of state of mixture
c	parameter in equation of state
f	fugacity
F	number of moles of original feed
i, j	component
K_c	phase equilibrium constant
k_{ij}	binary interaction coefficient
L	number of moles of liquid phase
N_c	number of component
P_c	critical pressure
P_{cap}	capillary pressure

P_L	pressure of liquid phase
P_V	pressure of vapor phase
r	pore radius
R	universal gas constant, 8.314 J/(mol·K)
R	range value
T	temperature
T_c	critical temperature
V	number of moles of vapor phase
V_m	molar volume
V_c	critical volume
x	mole fraction in vapor phase
y	mole fraction in liquid phase
z	overall mole fraction
Z_L	compressibility factor for liquid phase
Z_V	compressibility factor for vapor phase
$[P]$	parachor coefficient
φ	fugacity coefficient
ω	acentric factor
σ	interfacial tension
θ	contact angle

Abbreviations

PP, primary production process; CO2I, CO_2 injection process; MSCF, thousand standard cubic feet; MMP, minimum miscibility pressure; STB, standard tank barrel

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How to cite this article: Wu S, Li Z, Wang Z, Sarma HK, Zhang C, Wu M. Investigation of CO_2/N_2 injection in tight oil reservoirs with confinement effect. *Energy Sci Eng*. 2020;8:1194–1208. https://doi.org/10.1002/ese3.578