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A simulation research on evaluation of development in shale oil reservoirs by near-miscible CO₂ flooding

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Abstract
Shale oil is a key resource that could mitigate the impending energy shortage in the future. Despite its abundance in China, studies on shale oil are still at the preliminary stage. Shale oil development through CO₂ flooding has been successfully implemented in the United States. Therefore, the mechanics of CO₂ flooding in shale oil reservoirs should be investigated. This study applies a simulation method to evaluate the development efficiency of CO₂ flooding in shale oil reservoirs. Near-miscible CO₂ flooding can effectively develop shale oil. After 20 years, recovery could improve by up to 9.56% as a result of depletion development under near-miscible CO₂ flooding with 0.5% pore volume gas injection. Horizontal well injection is better than vertical well injection in terms of sweep efficiency and recovery. Cyclic gas injection is superior to continuous gas injection because the former reduces gas channelling. Thus, the use of horizontal wells with near-miscible cyclic gas injections has the potential to effectively develop shale oil reservoirs.

Keywords: shale oil, gas injection, near miscible flooding, numerical simulation

(Some figures may appear in colour only in the online journal)
Sheng et al (2014) studied the numerical simulation of shale oil cyclic gas injection and water gas slug gas injection development; they found that gas injection is feasible. The aforementioned research focused on non-miscible gas injection and first-contact fully miscible gas injection. Limited studies have been conducted on near-miscible gas injection in shale oil development. Gas injection in low permeability reservoirs in China has been studied (Johns et al 1994, Li 2007), but the theoretical research on shale oil development mainly focused on geological knowledge.

In China, the formation energy in shale oil reservoirs is low, the composition of crude oil is complex and the heterogeneity of reservoirs is strong. As a result, the gas injection parameters are difficult to control, and a mixed-phase state is difficult to achieve. The sweep efficiency of non-miscible flooding, despite being low, cannot meet the requirements of enhanced oil recovery. However, the near-miscible flooding requirements of injection pressure and component are loose and easy to implement in the field. We take a shale oil reservoir in the central and western regions of China as the research object. The simulation results of the near-miscible model as well as miscible and non-miscible gas injection through the solvent model are compared. Different well patterns and near-miscible gas injection are studied.

2. China shale oil resource

Shale oil was used by the Swedes, Scots, and French as early as 1637 as a source of fuel. The Swedes produced oil from alum shales until 1966, when other fuels became more readily available (Crawford et al 2008). Development of unconventional resources has become a major focus in China in the recent years through the growth in demand of energy. China has large shale oil resources in multiple basins which are at the early stage of delineation, evaluation, and testing. The most prospective are Sichuan, Tarim, Junggar, and Songliao basins. However, geologic and industry conditions of shale in China are less favorable than in North America. China’s shale oil deposits tend to be waxy and stored mainly in lacustrine-deposited shales, which may be clay-rich and less ‘frackable’ than the low-clay brittle marine shales productive in North America (Stevens et al 2013). Researchers analyzed and summarized elementary petroleum geological issues concerning continental shale oil in China, including sedimentary environment, reservoir space, geochemical features and accumulation mechanism (Zou et al 2013). A three step development road for shale oil is put forward, speeding up studies on ‘shale oil prospective areas’, stepping up the selection of ‘core areas’, and expanding ‘test areas’.

Many pilot projects on shale oil reservoirs have been initiated seeking economic development in modern hydraulic fracturing technologies. Fracturing these reservoirs is quite challenging and requires not only large reservoir contacts but also high fracture conductivity in both primary fracture and fracture networks since oil viscosity is several magnitudes higher than natural gas (Liu et al 2013). A mechanical seal sectional fracturing technique is used in well Jinye-1HF in Jiangsu province, and the production is ten times that of the production of a vertical fracturing well. In China, the gas injection in shale oil reservoir is just at the stage of mechanism study and simulation calculation, with almost no field application from published papers.

3. Basic model of near-miscible flooding

3.1. Near-miscible numerical simulation flooding method

The limitations of gas injection miscible flooding in field applications have been discovered by researchers in recent years. Firstly, miscible pressure is difficult to achieve if the stratum energy is insufficient. Secondly, the composition of injection gas has high requirements for miscible flooding, and the injection gas should be compatible with in-place oil. The oil composition changes with the development of oil fields; therefore, the composition of injection gas should be adjusted timely. Thirdly, the miscible zone in heterogeneous porous media is often unstable, making it difficult to reach miscibility because it is affected by many factors, such as heterogeneity, viscous force and gravity. The low sweep efficiency of non-miscible flooding is insufficient to the requirements of enhanced oil recovery (Fayers et al 2000). Therefore, near-miscible gas flooding is proposed (Johns et al 1994).

The calculation of a component model depends on the state equation and discretization of space and time. To process complex calculations, pseudo component and grid coarsening should be used in the component model calculation (Ceragioli 2008). If the composition of crude oil is unknown, the use of a calibrated black oil simulator is more accurate than using a coarse component model. We use the solvent model of the black oil simulator to simulate the gas injection flooding process. For the solvent model, the Todd–Longstaff coefficient correction method (Todd et al 1972) is used to calculate the fluid parameters of injection gas and crude oil composition. The 4th root of fluid mixing theory is the foundation of the determining parameters (Koval 1963).

In the Todd–Longstaff model, the determination method of effective viscosity between oil and gas miscible fluid is described below.

\[ \mu_{\text{ee}} = \mu_0^{1-\omega_m} \mu_m^{\omega_m} \quad (1) \]
\[ \mu_{\text{ge}} = \mu_0^{1-\omega_m} \mu_m^{\omega_m} \quad (2) \]
\[ \mu_m = \mu_0/[M_1^{1/4} + (M_1^{1/4} - 1)S_o/S]^4 \quad (3) \]
\[ M = \mu_0 \cdot \mu_g \quad (4) \]
\[ S = S_g + S_o \quad (5) \]

Where, \( \omega \) is the mixed-phase parameter, and it describes the incomplete miscible properties. The value of 0 indicates non-miscible displacement process, the value of 1 means completely miscible process, experience value is between 0.5 ~ 0.8.
(Stalkup 1983, Fayers et al 2000). \( \mu_o \) is the viscosity of oil in mPa.s, \( \mu_g \) is the viscosity of gas in mPa.s, \( \mu_m \) is the viscosity of mixture in mPa.s, \( M \) is the oil-gas mobility ratio, \( S_o \) is the oil saturation in decimal fraction, and \( S_g \) is the gas saturation in decimal fraction.

The values of \( \omega \) are assumed to be 1/3, 0.5 and 2/3 through the experimental study of Todd and Longstaff, with a good fitting effect under different mobility. The values of \( \omega \) in this paper are assumed to be 1/3, 0.5, 2/3 and 0.8. This assumption is combined with the research results of Stalkup (1983) and Jethwa et al (2000).

The effective density calculations of oil and gas can be represented as following, and are discussed in section 4.

\[
\rho_{oe} = \rho_o(1 - \omega) + \omega \rho_m
\]

\[
\rho_{ge} = \rho_g(1 - \omega) + \omega \rho_m
\]

\[
\rho_m = \rho_o(S_o/S_n)c + \rho_g(S_g/S_n)c
\]

\[
(S_o/S_n)c = M^{1/4} - (\mu_{oe}/\mu_{ge})^{1/4}/(M^{1/4} - 1)
\]

Where \( \rho_o \) is the density of oil in kg m\(^{-3}\), \( \rho_g \) is the density of gas in kg m\(^{-3}\), and \( \rho_m \) is the density of first contact miscible mixture in kg m\(^{-3}\).

### 3.2. Basic model of numerical simulation

A shale oil reservoir in the central and western regions of China is selected for numerical simulation studies to evaluate the shale reservoir development effect of gas injection. The block area is 10.1124 km\(^2\), with 6 fractured horizontal wells. The main production layer of the shale oil reservoir is the YC group. Table 1 shows the other basic parameters. In this model, the hydraulic fractures are placed along the path of the horizontal wells in the longitudinal direction, and these fractures are represented as zones of increased permeability in the grid that may extend tens of feet from the well. Therefore, the permeability of gridblocks with a well is increased to 100 mD. Another interpretation is to assume that a representative gridblock permeability is used to represent the hydraulic fracture permeability. Fractures are represented as zones of increased permeability around the wellbore. Fractures are assumed to be approximately 1/8 inch wide, and have a permeability around 1 million mD; thus, a gridblock 200 foot wide would have 100 mD average permeability. Figure 1 shows the permeability distribution in given block.

The feasibility of a basic model is verified through history matching. Scheme 1 is used as the basic model, and the wells are developed by depletion development. Horizontal well fracturing technology is the primary means to increase the production of depletion development. The fluid production and bottom-hole pressure (BHP) of six wells are matched, and the fitting accuracy can reach above 95%. The dynamic prediction of 20 years for the reservoir was reached on the basis of fitted parameters. The ultimate oil recovery and well production are low, and production declines rapidly under depletion development. Taking well A6 as an example, the production declines after 1200 d and reaches 0 after 3000 d. The decreasing production indicates the decline of stratum energy. The cumulative production of six wells in 20 years is 0.20 \( \times 10^6 \) stb and its recovery is 4.05%.

### 4. Research on CO2 injection development

#### 4.1. Near-miscible CO2 injection

We design different schemes to compare the effects of depletion development and different gas injection methods, such as near-miscible, immiscible and miscible. The mixed-phase parameters, \( \omega \), are 0, 0.33, 0.5, 0.67, 0.8 and 1.0 for scheme 2, scheme 3, scheme 4, scheme 5, scheme 6 and scheme 7, respectively. Two horizontal wells are transferred to gas injection in each scheme, and the BHP of the injection gas well is 21.4 MPa. Figure 2 shows pressure-volume-temperature (PVT) experimental data of injected CO2. The density of shale oil is 815.6 kg m\(^{-3}\). The relationships between density of mixture and oil saturation at different mixed-phase parameters are calculated with the Todd–Longstaff near-miscible model, and the calculation pressure is 49.111 MPa. The changes are shown in figure 3.

1. Compared with the depletion development, shale oil production can be significantly improved by near-miscible and miscible gas injection. The preliminary production of six horizontal wells in the depletion development is high, but the production decreases rapidly. Two horizontal wells are transferred to gas injection, and the production of four other horizontal wells is studied. Four horizontal production wells and two horizontal gas injection wells are developed for 20 years. The production rate, cumulative production and stable production period improved considerably. Under the immiscible gas injection development, the average production of the horizontal well is 8 m\(^3\)d\(^{-1}\), and the production time is more than 15 years. The preliminary production of near-miscible displacement is 137.52 m\(^3\)d\(^{-1}\), and the stable production period is 7.34 years, with the average single-well production at 12.72 m\(^3\)d\(^{-1}\). The preliminary production of gas injection increases when the mixed-phase parameter is 1. As the injection volume is approximately 0.8 pore volume (PV),

<table>
<thead>
<tr>
<th>Parameter names</th>
<th>Parameter value</th>
<th>Parameter names</th>
<th>Parameter value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid number</td>
<td>53 ( \times ) 53 ( \times ) 8</td>
<td>The initial oil saturation</td>
<td>0.75</td>
</tr>
<tr>
<td>Grid size</td>
<td>60 m ( \times ) 60 m ( \times ) 1 m</td>
<td>Porosity</td>
<td>0.075</td>
</tr>
<tr>
<td>Permeability</td>
<td>YC10 group</td>
<td>The depth of the top of reservoir</td>
<td>2286 m</td>
</tr>
<tr>
<td></td>
<td>Ch6 group</td>
<td>Relative density of crude oil</td>
<td>0.8156</td>
</tr>
</tbody>
</table>

Table 1. The static parameters of numerical simulation.
2. Oil recovery extent increases as the mixing degree increases. Compared with non-miscible displacement, the near-miscible displacement has a recovery extent of more than 0.41% when the mixed-phase parameter is 0.3, the recovery extent is more than 0.98% when the mixed-phase parameter is 0.8 and it is more than 1.15% when the displacement is completely miscible. Figure 4 shows the production development and recovery extent under different displacements.

3. The viscous fingering phenomenon becomes evident, the gas channelling occurs early and the spread degree is low when the mixing degree is low. The gas channelling time of non-miscible displacement is 1366.92 d. The time of near-miscible displacement is 1459.17 d, in which the mixed-phase parameter is 0.3. Table 2 shows the gas channelling time of other near-miscible displacements. Figure 5 shows the remaining oil saturation distribution after 20 years development. The plane sweep efficiency of gas drive increases as the mixing degree increases.

4.2. Approximate miscible CO₂ injection in horizontal and vertical wells

To evaluate the effects of the type and well pattern of the CO₂ injection well on the oil shale development, scheme 6 is selected as the foundation scheme, and schemes 8 to 10 are added. These three added schemes are near-miscible displacement. The BHP of the injection wells is 21.4 MPa. The A1 and A6 wells are converted into the injection well after 1200 d. Table 3 shows the detail of each scheme and the development effects.

1. The effect of using horizontal well injection–production is better than that of vertical well injection–production on the whole. The recovery of scheme that includes horizontal injection wells is more than in other schemes, which include vertical injection wells. The injection of vertical wells is more effective than horizontal wells, but the recovery of scheme 9 is higher at 1.25% than the recovery of scheme 8. The development effect of the horizontal production well is better than that of the vertical production well. The recovery of scheme 8 is 0.85% more than the recovery of scheme 10. Figure 6 shows the production development and recovery extent under different schemes. The sweep efficiency of horizontal well injection–production is higher than that of the vertical well, and the efficiency of oil extraction is better.

2. Shale oil production can be significantly improved with the encryption of injection–production patterns. Sweep efficiency, displacement efficiency and recovery can also be increased. The horizontal well production is high after the current well pattern is encrypted. The production change includes rising and decreasing stages. In scheme 8, two vertical injection wells and two horizontal production wells are encrypted on the basis of scheme 6. The recovery of scheme 8 is 15.94% higher than the recovery of scheme 6. In scheme 9, two horizontal injection wells and two horizontal production wells are encrypted on the
basis of scheme 6, and the recovery of scheme 9 is 17.19% more than the recovery of scheme 6. In scheme 10, two vertical injection wells and two vertical production wells are encrypted on the basis of scheme 6, and the recovery of scheme 10 is 15.09% higher than the recovery of scheme 6.

3. The stability of the formation pressure can be maintained by these three kinds of gas injection development. The injection amount of vertical wells is more than the injection amount of horizontal wells, but the formation pressure is higher than in the horizontal gas injection wells. The injection amount of scheme 8 is 0.245 PV, which is more than that in scheme 9 at 0.17 PV; however, the formation pressure during the late stage of development in scheme 9 at 32.16 MPa is higher than that in scheme 8. The pressure

---

Table 2. Comparison of results between CO$_2$ flooding and primary depletion.

<table>
<thead>
<tr>
<th>Schemes</th>
<th>Injection volume (PV)</th>
<th>Recovery (%)</th>
<th>Average reservoir pressure after 20 years (MPa)</th>
<th>Gas channeling time (days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scheme 1</td>
<td>0</td>
<td>4.050</td>
<td>21.36</td>
<td>/</td>
</tr>
<tr>
<td>Scheme 2</td>
<td>0</td>
<td>6.302</td>
<td>12.48</td>
<td>32.58</td>
</tr>
<tr>
<td>Scheme 3</td>
<td>0.33</td>
<td>6.308</td>
<td>12.89</td>
<td>32.55</td>
</tr>
<tr>
<td>Scheme 4</td>
<td>0.50</td>
<td>6.375</td>
<td>13.13</td>
<td>32.50</td>
</tr>
<tr>
<td>Scheme 5</td>
<td>0.67</td>
<td>6.458</td>
<td>13.32</td>
<td>32.46</td>
</tr>
<tr>
<td>Scheme 6</td>
<td>0.80</td>
<td>6.524</td>
<td>13.45</td>
<td>32.43</td>
</tr>
</tbody>
</table>

Table 3. Comparison of results between CO$_2$ flooding projects by horizontal wells and vertical wells.

<table>
<thead>
<tr>
<th>Schemes</th>
<th>Encryption of production wells</th>
<th>Encryption of gas injection wells</th>
<th>Injection (PV)</th>
<th>Recovery (%)</th>
<th>Average reservoir pressure after 20 years (MPa)</th>
<th>Gas channeling time (days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scheme 6</td>
<td>—</td>
<td>—</td>
<td>0.065</td>
<td>13.45</td>
<td>32.21</td>
<td>1306.67</td>
</tr>
<tr>
<td>Scheme 8</td>
<td>Two horizontal wells</td>
<td>Two vertical wells</td>
<td>0.245</td>
<td>29.39</td>
<td>31.63</td>
<td>668.17</td>
</tr>
<tr>
<td>Scheme 9</td>
<td>Two horizontal wells</td>
<td>Two horizontal wells</td>
<td>0.228</td>
<td>30.64</td>
<td>32.16</td>
<td>395.42</td>
</tr>
<tr>
<td>Scheme 10</td>
<td>Two vertical wells</td>
<td>Two vertical wells</td>
<td>0.217</td>
<td>28.54</td>
<td>32.88</td>
<td>668.17</td>
</tr>
</tbody>
</table>

---

Figure 4. Comparison of production rate & recovery between various gas injection and primary depletion.

Figure 5. Comparison of saturation distribution between various gas injection and primary depletion.
stability of the horizontal well is worse than the pressure stability of the vertical well. At the late production period, the formation pressure in scheme 10 is higher than that in scheme 8 by 1.25 MPa. Table 3 and figure 7 show the dynamic changes in the different schemes.

Considering the gas production of adjacent wells, when vertical wells are gas injection wells, the gas production of adjacent wells is small and gas is channelled late. However, the gas production of the wells near the horizontal gas injection wells is large and gas channelling occurs earlier. The oil displacement efficiency is reduced when the injection well is a horizontal well. Taking schemes 8 and 9 as examples, the gas channelling of horizontal gas injection occurs in 395.42 d after the gas injection began; the gas production of well A2 is $40000 \, \text{m}^3/\text{d}$ after 8 years from the occurrence of gas channelling. The gas channelling of vertical gas injection occurs 668.17 d after gas injection began; the gas production of well A2 is $30000 \, \text{m}^3/\text{d}$ after 8 years from the occurrence of gas channelling. Figure 8 shows the changes in gas production under different situations. Some measures should be adapted to delay the occurrence of gas channelling during the horizontal well gas displacement. The displacement efficiency can be improved by these measures.

4.3. Gas recycling injection

Gas recycling injection is widely applied in actual production. Continuous gas injection at an area without a sufficient gas source is difficult, and unstable factors could interfere with continuous gas injection. However, the lack of a gas source can be solved to a certain degree by gas recycling injection,
The gas recycling injection can be adjusted more flexibly and effectively with the fluctuation of oil prices.

To explore the development effect of the near-miscible gas recycling injection, we compared the continuous gas injection with the gas recycling injection under the given mixed-phase parameter. The development effects are also analysed on the basis of different miscible degrees, different gas injection cycles and gas recycling injections. A total of 7 schemes are established, the 11th scheme of which is continuous gas injection under the mixing coefficient of 0.8. The mixing coefficient of scheme 12, scheme 13, scheme 14, scheme 15, and scheme 16 are 0, 0.33, 0.5, 0.67 and 0.8, respectively. The gas injection and stop injection cycles are 6 months, and the injection amount is 4.37 PV. Scheme 17 is established under the mixing coefficient of 0.8 to analyse the effect of gas injection cycle on the gas injection effect. The gas injection and stop injection cycles are 3 months, and

### Table 4. Comparison of results between cyclic and continuous injection projects.

<table>
<thead>
<tr>
<th>Schemes</th>
<th>Gas injection style</th>
<th>ω</th>
<th>Injection (PV)</th>
<th>Recovery (%)</th>
<th>Average reservoir pressure after 20 years (MPa)</th>
<th>Gas channeling time (days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scheme 11</td>
<td>Continuous gas injection</td>
<td>0.8</td>
<td>4.53</td>
<td>19.31</td>
<td>26.50</td>
<td>1003.75</td>
</tr>
<tr>
<td>Scheme 12</td>
<td>Gas recycling injection (6 M)</td>
<td>0</td>
<td>4.37</td>
<td>16.05</td>
<td>27.22</td>
<td>1550.42</td>
</tr>
<tr>
<td>Scheme 13</td>
<td>Gas recycling injection (6 M)</td>
<td>0.33</td>
<td>4.37</td>
<td>17.55</td>
<td>27.22</td>
<td>1701.50</td>
</tr>
<tr>
<td>Scheme 14</td>
<td>Gas recycling injection (6 M)</td>
<td>0.5</td>
<td>4.37</td>
<td>18.40</td>
<td>27.13</td>
<td>1823.17</td>
</tr>
<tr>
<td>Scheme 15</td>
<td>Gas recycling injection (6 M)</td>
<td>0.67</td>
<td>4.37</td>
<td>18.74</td>
<td>27.07</td>
<td>1974.25</td>
</tr>
<tr>
<td>Scheme 16</td>
<td>Gas recycling injection (6 M)</td>
<td>0.8</td>
<td>4.37</td>
<td>19.29</td>
<td>26.93</td>
<td>2126.33</td>
</tr>
<tr>
<td>Scheme 17</td>
<td>Gas recycling injection (3 M)</td>
<td>0.8</td>
<td>4.44</td>
<td>19.47</td>
<td>26.81</td>
<td>2004.67</td>
</tr>
</tbody>
</table>

![Figure 9. Comparison of production rate & recovery between cyclic and continuous injection projects.](image)

![Figure 10. Comparison of pressure & Gas/Oil ratio between cyclic and continuous injection projects.](image)

easing gas supply and demands. The gas recycling injection can be adjusted more flexibly and effectively with the fluctuation of oil prices.

To explore the development effect of the near-miscible gas recycling injection, we compared the continuous gas injection with the gas recycling injection under the given mixed-phase parameter. The development effects are also analysed on the basis of different miscible degrees, different gas injection cycles and gas recycling injections. A total of
the injection amount is 4.44 PV. Table 4 shows the numerical simulation results.

1. The recovery extent of gas recycling injection is similar to that of continuous gas injection under the same total injection volume. At the initial stage of development, the recovery extent of gas recycling injection is lower than that of continuous gas injection. However, after 20 years of development, the recovery extent of gas recycling injection is slightly higher than the recovery extent of continuous gas injection. Compared with the current yield of the continuous gas injection, the current yield of the gas recycling injection is fluctuant before finally reaching flat, which indicates that the gas injection effect decreases as the gas production in the gas channelling increases. Figure 9 shows the dynamic changes in oil production and recovery extent.

2. Formation pressure can be maintained to a certain degree by gas recycling injection and continuous gas injection; however, the formation pressure is fluctuant under the gas recycling injection, and the pressure tends to stabilize at a later time. Figure 10 shows the dynamic changes in formation pressure and gas-oil ratio.

3. Gas channelling can be retarded by the gas recycling injection. The total oil production is similar under gas recycling injection and continuous gas injection, but the gas–oil ratio of gas recycling injection is lower than that of continuous gas injection. Compared with the gas channelling time of scheme 12, the gas channelling time of scheme 11 decreases by 121.667 d, indicating that gas channelling can be effectively controlled by gas recycling injection.

5. Discussion

5.1. Effect of heterogeneity

5.1.1. Effect of permeability variance. This part investigates how heterogeneity impacts CO2 solvent flooding in shale oil reservoirs. The heterogeneous permeability distribution is randomly generated but with Gaussian distribution. Figure 11 shows the case of Gaussian distribution with horizontal permeability variance (δx) at 0.6 and its correspondingly generated model. More cases with different permeability variance (δ) are studied both vertically and horizontally, while the mean permeability for each case is set to one common value.
Six scenarios with different horizontal permeability variance are performed to evaluate the areal heterogeneity on CO2 flooding performance. Another five scenarios are used for the case of vertical heterogeneity ($\delta_z$). The basic simulation model for those scenarios is scheme 9 except that the average permeability for each scenario is assumed as 2.5 mD. Further, to find a parameter which implies the efficiency of CO2 solvent flooding, cumulative exchange ratio (CER) is introduced and defined as cumulative incremental oil volume divided by cumulative CO2 volume, with a unit of stb Mscf$^{-1}$. Larger CER means a relative higher efficiency. In the life of gas flooding oilfields, time at the peak of CER could be assumed as the most efficient period.

1. Results indicate that CO2 solvent flooding would be more efficient in slight areal heterogeneous reservoirs than both homogeneous reservoirs and serious areal heterogeneous reservoirs. As shown in figure 12(a), the time at the peak of CER would be delayed and the maximum efficiency would be largely reduced with the increasing horizontal permeability variance. At the early periods before gas breakthrough, to some degree, serious heterogeneity can release gas fingering in the horizontal direction and thus cause a time lag in reaching the peak of CER. Although the homogeneous model has the largest CER at an early time, as shown in figure 12(b), cases of lower heterogeneity ($\delta_x = 0.2, 0.4, 0.5$) have larger ultimate oil recovery than homogeneous case ($\delta_x = 0$) and serious cases ($\delta_x = 0.6, 0.8$). The recovery of the three cases $\delta_x = 0.2, 0.4, 0.5$ are almost the same. Such consistence illustrates that the performance of CO2 solvent flooding in shale oil reservoirs is less sensitive to permeability variance if $\delta_x < 0.5$. However, in serious heterogeneous reservoirs, both solvent and hydrocarbon would flow through the main path with higher permeability, leaving some oil trapped in smaller pores and obtain poor recovery.

2. Compared with areal heterogeneity, the performance of shale oil reservoirs by CO2 flooding is less sensitive to vertical heterogeneity. The time lag and shift of peaks in figure 13(a) is not as evident as shown in figure 12(a). However, similar conclusion can be arrived at through CO2 solvent flooding which would be more efficient in slight vertical heterogeneous reservoirs than in both homogeneous and serious vertical heterogeneous cases. Also, the performance of CO2 solvent flooding in shale oil reservoirs is less sensitive to vertical permeability variance.

Figure 13. Comparison of CO2 flooding performance in various vertical heterogeneous models. (a) Cumulative exchange ratio versus time. (b) Recovery versus cumulative injected volume.

Figure 14. Comparison of CO2 flooding performance in various vertical heterogeneous models. (a) Cumulative exchange ratio versus time. (b) Recovery versus cumulative injected volume.
variance ($\delta_y$) when $\delta_y < 0.5$. As shown in figure 13(b), scenarios with slight heterogeneity ($\delta_y = 0.2, 0.4, 0.5$) have larger recovery than in the homogeneous case ($\delta_y = 0$) and serious cases ($\delta_y = 0.6, 0.8$). One possible reason is that slight vertical heterogeneity can reduce the effect of gravity override, which happens in homogeneous models. Although serious vertical heterogeneity can also play such a role, gas channeling would be more prominent and thus cause poor sweep efficiency in lower permeability layers.

The extreme case of significant heterogeneous is natural fractured shale oil reservoirs. With a larger density of natural fractures, the areal and vertical heterogeneity would significantly increase. In such oil plays, CO$_2$ solvent flooding would mainly displace and exchange the oil reserves in higher conductive natural fractures instead of the shale pores with quite low permeability. The ultimate oil recovery in natural fractured shale oil reservoirs would then be low. Investigation on how the density and orientation of natural fractures impacts CO$_2$ solvent flooding in shale oil reservoirs would be in the scope of future work.

5.1.2. Effect of the ratio between vertical permeability and horizontal permeability. Four scenarios with different ratio between vertical permeability and horizontal permeability ($k_z/k_x = 0.001, 0.01, 0.1, 1$) are compared and shown in this section. The horizontal permeability for each case is assumed to be the same but with different vertical permeability.

Results indicate that $k_z/k_x$ has a negative effect on the recovery performance of CO$_2$ solvent flooding. In the early periods, as shown in figure 14(a), cases with higher $k_z/k_x$ (0.1, 1) reach the peak of CER earlier and have larger CER than cases with lower $k_z/k_x$ (0.001, 0.01). But, in the long run, cases with lower $k_z/k_x$ have higher ultimate oil recovery than cases with higher $k_z/k_x$ (figure 14(b)).

When $k_z/k_x$ is less than 0.001, there is no communication and the transport front advances evenly in the vertical direction (figure 15). But as $k_z/k_x$ increases over 0.01, the effect of gravity override becomes evident and thus the transport front advances unevenly in the vertical direction. CO$_2$ solvent is much less dense than the hydrocarbon in this shale oil reservoir. So, solvent tends to gravity segregate to the top. Displacement and mixing would preferably happen in the upper part. The oil recovery and flooding efficient would then be impaired.

5.2. Economic analysis

Previous study has provided economic assessment on miscible and immiscible CO$_2$ flooding in conventional and unconventional oil reservoirs. Here we presented the results of economic analysis on near miscible CO$_2$ solvent flooding shale
oil reservoirs. The net present value (NPV) model has been employed to evaluate the economic potential for different cases.

5.2.1 Near miscible CO\textsubscript{2} solvent flooding. Compared with depletion, gas flooding is more profitable and has longer economic production periods. Primary investments mainly include CO\textsubscript{2} gas purchase, converting production wells into gas injection wells and pumping into wellbores. Such costs are relatively small to just convert existing oil wells into gas injection wells rather than drilling new wells. In figure 16, oil price for all cases is assumed to be 60$. Further, the breakeven time is also quite short. Only less than one year is needed to balance the expense for gas flooding. The NPV of different gas flooding scenarios increases as the mixing degree increases. However, there are no obvious increments of NPV from cases of \( w = 0.8 \) to \( w = 1.0 \). For these deep shale oil reservoirs, minimum mixing pressure is usually too high to reach. In such cases, near miscible CO\textsubscript{2} solvent flooding is an economic alternative.

5.2.2 Approximate miscible CO\textsubscript{2} injection in horizontal and vertical wells. Economic analysis is performed on different infill drilling schemes. Detailed information about these four schemes has been described in table 2.

By contrast, infill drilling of both production wells and injection wells can bring significant NPV increment after 5 years’ operation. Scheme 6 just converts producers to injectors without any infilling. In figure 17, oil price for all cases is assumed to be 60$. As shown in figure 17, the primary investments for scheme 6 are relatively low but increments are much less than the other three infilling cases. Both infilling vertical wells and horizontal wells need a lot of capital for drilling and completion. However, infilling cases only take about 1 year to breakeven, except scheme 8 which needs about two years. Infilling horizontal producers and injectors, as in scheme 9, are most profitable in the long term, although a large amount of starting capital is also needed. Therefore, one possible way is to convert producers to injectors without enough circulating capital at early periods, and then infill horizontal wells when the financial situation allows.

5.2.3 Gas recycling injection. Gas recycling injection is less profitable than continuous injection. In figure 18, oil price for each case is assumed to be 60$. As shown in figure 18, NPV for gas recycling injection fluctuates with time. Such fluctuation would make gas recycling injection more flexible to the changing oil prices.

NPV for both gas recycling injection and continuous injection are quite sensitive to oil price. As shown in figures 19(a) and (b), NPV after ten years’ operation at the oil price 80$ is about 6 times larger than the case of 40$. Oil price also determines the breakeven point for each project. It only takes less than one year to balance all the costs for continuous gas injection project when the oil price stays at 80$, while more than 3 years are needed for the case of 40$. As shown in figure 20, the breakeven time is quite sensitive to oil price. As oil price increases to 80$, the breakeven time for gas recycling injection and continuous injection are approaching. This indicates that gas recycling is preferably implemented when the oil price is lower than 80$.

Economic assessment is also necessary in the case of low oil price. Technology should always be served to lower the overall cost of oil recovery. In such case, water injection into hydraulic fractured wells, or water alternating gas (WAG), might be promising to be economically efficient. Technological and economic evaluation of CO\textsubscript{2} solvent flooding or WAG in this shale oil reservoir would also be the scope in future work.

![Figure 19. Comparison of NPV between continuous gas injection and cycle gas injection. (a) Continuous gas injection. (b) Gas recycling injection.](image1)

![Figure 20. Comparison of breakeven time between continuous gas injection and gas recycling injection.](image2)
6. Conclusion and suggestions

1. The formation pressure can be maintained and the recovery extent can be improved by near-miscible gas injection. Near-miscible injection has great advantages over non-miscible gas injection in enhanced oil recovery. A low mixed-phase level indicates that gas channelling occurs early. When the degree of miscibility is great, recovery extent is high and the pressure decays slowly. However, the development effect is slightly influenced by increase of the mixed-phase parameter when it is more than 0.8.

2. Comparing the injection-production of horizontal wells with that of vertical well injection, the former's sweep efficiency and recovery extent are greater, and the formation pressure can be stably maintained. However, the gas channelling time of horizontal well gas injection occurs earlier than that of the vertical well. Gas production is high after gas channelling, and some measures are necessary to reduce the occurrence of gas channelling. Considering the economic potential of infilling, drilling horizontal producers and vertical injectors is proposed in the further development.

3. Gas recycling injection has advantages over continuous gas injection. Gas recycling injection can delay the occurrence of gas channelling and would also be preferable at lower oil prices.

4. Both slight areal heterogeneity and vertical heterogeneity could contribute to more efficient solvent flooding and a higher oil recovery. Serious heterogeneity would reversely cause poor oil recovery.

5. The component model should be used for numerical simulation when the shale oil component data are more extensive. The influences of artificial fractures through hydraulic fracturing and natural fractures on gas injection development of shale oil require further study.

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