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Research Article

Simulation Study on Miscibility Effect of CO_2/Solvent Injection for Enhanced Oil Recovery at Nonisothermal Conditions

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The minimum miscibility pressure (MMP) determines the main mechanism of CO_2 flooding, which is either an immiscible or miscible process. This paper examines the recovery improvements of CO_2 flooding in terms of both the injection temperature and solvent composition. The results show that a lower temperature injection and LPG (liquefied petroleum gas) mixture can considerably improve oil recovery due to the reduced MMP in the swept area caused by the injected solvent. For the pure CO_2 injection at the reservoir temperature, oil recovery is 59% after 1.0 PV CO_2 injection. The oil recoveries by CO_2-LPG mixtures are improved to 73% with 0.1 mole fractions of LPG and 81% with 0.2 mole fractions of LPG. The recovery factor from low-temperature CO_2 injection is 78%, which is 32% higher compared to the isothermal case. The recoveries obtained by low-temperature CO_2-LPG injection increase up to 87% of the initial oil. Heat transfer between the reservoir and the formation of over/underburden should be considered in order to describe the process more accurately. Additionally, the recovery factors from the heat transfer models are decreased by 4–12% in comparison with the original nonisothermal models.

1. Introduction

CO_2 flooding is a common process used to enhance oil recovery for light to medium crude oil and is generally implemented to recover the remaining oil after waterflooding [1, 2]. The performance of CO_2 flooding is mainly affected by the minimum miscibility pressure (MMP). The MMP of CO_2 is known to depend on various parameters including the temperature, pressure, molecular weight of the heavy fraction, and composition of the injecting solvent [3–12]. Generally, high temperature and large mole fractions of the heavy component result in a high MMP [13].

To examine the effects of temperature on the MMP and recovery factor of CO_2 flooding, a number of experimental studies have been conducted. Holm and Josendal [4] defined a simple correlation for the CO_2 MMP versus the reservoir temperature and C_{5+} molecular weight of the oil. Stalkup [5] showed that the CO_2 purity, oil composition, and reservoir temperature determine the MMP. Yellig and Metcalfe [6] stated that the CO_2 MMP is significantly influenced by the reservoir temperature. Johnson and Pollin [8] looked at the molecular weight, oil gravity, reservoir temperature, and injection gas composition in an attempt to improve the accuracy of MMP correlation. Alston et al. [9] analyzed the temperature, C_{5+} molecular weight, volatile oil fraction, intermediate oil fraction, and composition of the injected CO_2.

Low-temperature injection was first applied by Shu [14]. Injection of a coolant decreases the MMP, thereby increasing the recovery. He suggested an equation to calculate the CO_2 MMP reduction in terms of the coolant volume. This equation, however, assumes that the injected fluids are entirely mixed with the reservoir oil. Khanzode [15], Wang [16], and Wang et al. [17] performed numerical simulations to prove the potential of reservoir cooling for enhanced oil recovery from CO_2 injection. They considered temperature gradients in realistic reservoir situations. Although the injection composition, like the injection temperature, is known to affect the MMP, these simulation studies only considered the effect of the injection temperature on the MMP.

CO_2 can be injected in an immiscible or near-miscible process at reservoir conditions. The performance of the immiscible process is generally lower than that of the miscible flood. The recovery in immiscible conditions can be improved by lowering the CO_2 MMP via injection of a LPG (liquefied petroleum gas). Kumar and Von Gonten [19] investigated the recovery by injecting mixtures of CO_2 and LPG. They carried out experiments with Woodruff reservoir oil in Berea sandstone cores. The recovery of the mixture injection was 11% higher than that using only a CO_2 injection. Lee et al. [20] optimized the injection composition for gas injection. Their results stated that an injectant rich in C_3 to C_4 led to a higher oil rate with higher API oil. Delfani et al. [21] simulated the gas injection process in the Iranian field. The performance of LPG injection was better than that of CO_2 flooding.

Various researchers have explained that both the temperature and injection composition are important factors that influence the recovery efficiency. However, the effect of temperature has been often ignored in most simulations of gas flooding. This study investigates the combined effects of the temperature of the injected fluids and the composition of the CO_2-LPG mixture on oil recovery. A lower temperature solvent and composition of the solvent can impact the MMP, which subsequently affects the oil recovery. The fluid model used for MMP calculation, reservoir model, and injection schemes is indicated. The recovery factors are analyzed with respect to the LPG mole fraction and injection temperature with an integrated model of compositional flow and heat transfer in the reservoir.

2. Methodology

2.1. Model Formulation. Simulations of CO_2 flood were conducted with GEM, which is a 3D, multicomponent, multiphase, compositional simulator considering important mechanisms of miscible gas injection process such as composition changes of reservoir fluids, swelling of oil, viscosity reduction, and the development of a miscible solvent bank through multiple contacts.

The basic mass conservation equation for components can be written as follows:

$$\frac{\partial}{\partial t}\left(\phi\sum_{j=1}^{N_p}\rho_j S_j\right)+\nabla\cdot\left(\sum_{j=1}^{N_p}\rho_j \mathbf{u}_j\right)=0, \tag{1}$$

where ϕ is the porosity, j the phase index, N_p the total number of phases, ρ_j the density of phase j, and $\mathbf{u}_j$ the Darcy velocity of phase j.

The phase flux from Darcy's law is

$$\mathbf{u}_j=-\frac{\mathbf{k}k_{rj}}{\mu_j}\nabla\left(p_j-\gamma_j h\right), \tag{2}$$

where $\mathbf{k}$ is the intrinsic permeability tensor, h the vertical depth, k_{rj} the relative permeability, μ_j the viscosity, and γ_j the specific weight of phase j.

To describe nonisothermal conditions and investigate their influence on oil recovery, thermal module was also used. General total energy balance in the reservoir by conduction and convection can be described as follows:

$$\begin{aligned}\frac{\partial}{\partial t}&\left[\left(1-\phi\right)\rho_s C_{vs}+\phi\sum_{j=1}^{N_p}\rho_j S_j C_{vj}\right]T+\nabla\\&\cdot\left(\sum_{j=1}^{N_p}\rho_j C_{pj}\mathbf{u}_j T-\lambda_T\nabla T\right)+Q_{\mathrm{loss}}=0,\end{aligned} \tag{3}$$

where T is the reservoir temperature, ρ_s is the density of rock, C_{vs} and C_{vj} are the heat capacities of rock and phase j at constant volume, C_{pj} is the heat capacity of phase j at constant pressure, λ_T is the thermal conductivity, and Q_{loss} is the heat loss to overburden and underburden formations.

Heat transfer between the reservoir and surrounding formations should be considered to more accurately describe the recovery process. When the injected fluids flow through the reservoir, heat transfer occurs between the reservoir and over/underburden across its boundaries. Vinsome and Weterveld's semianalytical method [22] is used to calculate the heat loss by linear conduction. It assumes that conduction within surrounding rocks rapidly eliminates any temperature differences and longitudinal heat conduction in the surroundings can be neglected. The temperature profile in the over/underburden can be calculated as function of time and distance from reservoir interface by

$$T\left(t,z\right)=\left(\theta-\theta^0+b_1 z+b_2 z^2\right)\exp\left(-\frac{z}{d}\right)+\theta^0, \tag{4}$$

where $T(t,z)$ is the over/underburden temperature at time t at a distance z from the reservoir boundary, b_1 and b_2 are the time dependent parameters, d is the thermal diffusion length, θ is the temperature in the boundary grid block, and θ^0 is the initial temperature in the boundary grid block. The diffusion length d is represented by

$$d=\frac{\sqrt{\eta t}}{2}, \tag{5}$$

where η is the thermal diffusivity defined by

$$\eta=\frac{\kappa_R}{C_R\widetilde{\rho}_R}. \tag{6}$$

Table 1: Composition of simulated oil.

Component	Mole fraction
N_2	0.0096
CO_2	0.0058
H_2S	0.0030
C_1	0.0449
C_2	0.0299
C_3	0.0475
IC_4	0.0081
NC_4	0.0192
IC_5	0.0127
NC_5	0.0219
C_6 to C_9	0.2573
C_{10} to C_{17}	0.2698
C_{18} to C_{27}	0.1328
C_{28+}	0.1375
Sum	1

Here, κ_R is the rock thermal conductivity, C_R is the rock heat capacity, and $\tilde{\rho}_R$ is the mass density of the rock. Parameters b_1 and b_2 are derived as

$$b_1^{n+1} = \frac{\eta\Delta t\left(\theta^{n+1}-\theta^0\right)/d^{n+1}+\xi^n-\left(d^{n+1}\right)^3\left(\theta^{n+1}-\theta^n\right)/\eta\Delta t}{3\left(d^{n+1}\right)^2+\eta\Delta t},$$
$$b_2^{n+1} = \frac{2b_1^{n+1}\left(d^{n+1}\right)-\left(\theta^{n+1}-\theta^0\right)+\left(d^{n+1}\right)^2\left(\theta^{n+1}-\theta^n\right)/\eta\Delta t}{2\left(d^{n+1}\right)^2}, \quad (7)$$

where

$$\xi^n = \left[\left(\theta-\theta^0\right)d+b_1d^2+2b_2d^3\right]^n \quad (8)$$

and the heat loss rate Q_{loss} is

$$Q_{\text{loss}} = \kappa_R A\left[\frac{\left(\theta^{n+1}-\theta^0\right)}{d^{n+1}}-b_1^{n+1}\right], \quad (9)$$

where A is the cross-sectional area for heat loss to the overburden and underburden.

2.2. Crude Oil Characterization. Oil from the Weyburn reservoir [18, 23, 24] is chosen to model the reservoir oil. The saturation pressure is 2.89 MPa at 59°C. The oil composition is shown in Table 1. Table 2 represents PVT properties as a function of dissolved gas mole fraction. The properties include saturation pressure, gas oil ratio (GOR), gas solubility, formation volume factor (FVF), and swelling factor (SF). Fluid characterization, lumping of components, and matching with laboratory data through regression are carried out by fluid modeling with WinProp of CMG. The oil density and viscosity are matched with experimental results [18] through

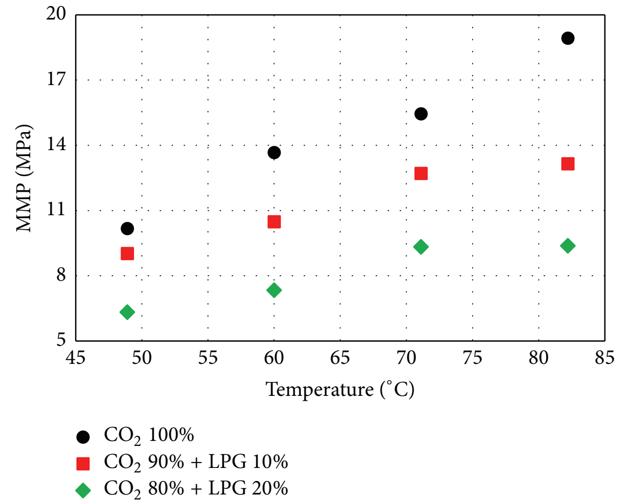

Figure 1: Variation of the MMP with temperature.

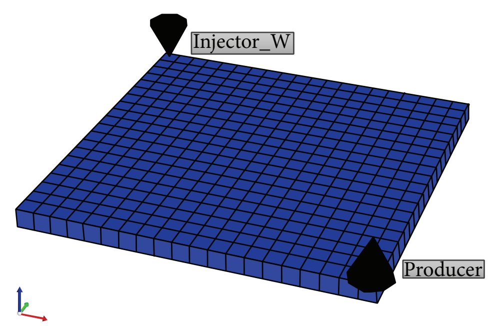

Figure 2: One-fourth of the 2D, five spot reservoir model.

the Peng-Robinson equation of state model (Tables 3 and 4). Table 5 represents viscosity data for the oil and CO_2 mixture. The CO_2 MMP was calculated using the multiple-mixing-cell method [25] over a temperature range of 49–82°C. The predicted MMPs at 82°C are 18.9 MPa for CO_2, 13.2 MPa for 90% CO_2 with 10% LPG, and 9.4 MPa for 80% CO_2 with 20% LPG. The LPG consists of 0.2 mole fractions of propane and 0.8 mole fractions of butane. The MMPs are plotted against temperature in Figure 1. This result explains that the MMP decreases as the temperature decreases and the concentration of LPG increases.

2.3. 2D Homogeneous Reservoir Model. A 2D hypothetical model is illustrated in Figure 2 and its properties are shown in Table 6. The length and width are both 60 m and the thickness is 3 m with a Cartesian grid of 20 × 20 × 1 grid blocks. The porosity (0.2) and permeability (2.96 × 10^{-7} m^2) are constant. Relative permeability curves are obtained from waterflooding in Weyburn field (Figure 3) [26]. The initial water and oil saturations are set at 0.2 and 0.8, respectively. The reservoir assumes an initial pressure of 13.8 MPa and an initial temperature of 82°C. The producer operates at a constant pressure condition of 11 MPa. 1.0 PV (pore volume) of water is injected, followed by the injection of 1.0 PV

Table 2: PVT properties of the reservoir fluid and CO_2 mixtures at 59°C [18].

Dissolved gas mole fraction	Saturation pressure (MPa)	GOR (sm^3/m^3)	Gas solubility (sm^3/m^3)	FVF (m^3/m^3)	SF (m^3/m^3)
0.0058	2.9	19	0	1.087	1.074
0.158	4.5	42	23	1.143	1.130
0.412	8.0	113	94	1.308	1.292
0.439	8.4	125	106	1.336	1.320
0.521	9.9	158	139	1.409	1.392
0.595	11.4	221	202	1.546	1.527
0.641	12.6	263	244	1.634	1.614
0.826	19.7	875	856	2.694	2.668

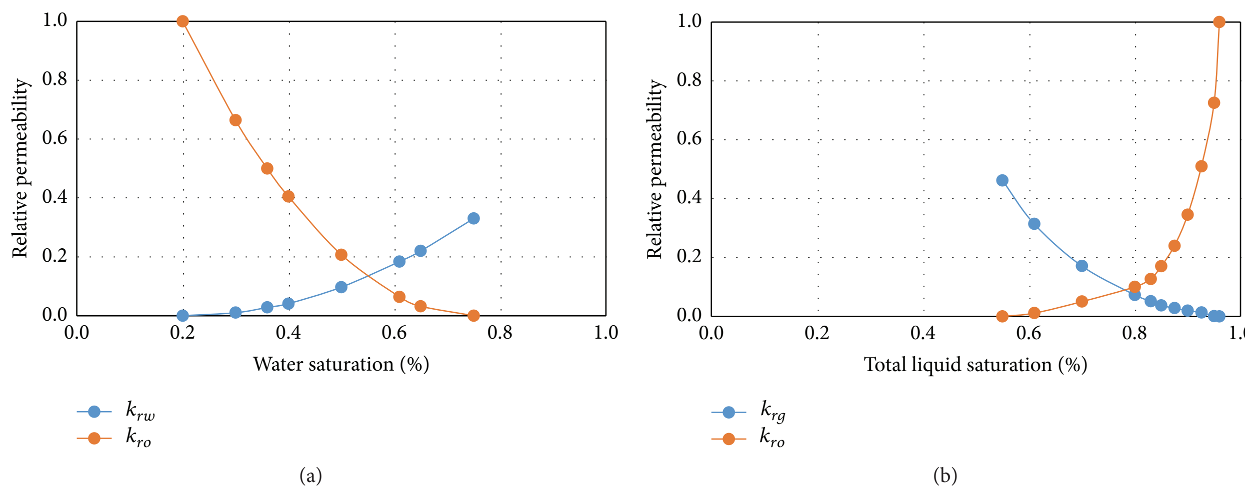

Figure 3: Relative permeability curves in Weyburn field: (a) oil-water relative permeability and (b) oil-gas relative permeability.

Table 3: Density and viscosity data of simulated oil at 0.1 MPa.

Temperature (°C)	Density (kg/m^3)	Viscosity (mPa·s)
15	878.1	—
20	876.8	5.2
59	836.7	3.2

Table 4: Density and viscosity data of simulated oil at 59°C.

Pressure (MPa)	Density (kg/m^3)	Viscosity (mPa·s)
0.1	836.1	3.2
3.54	843.4	4.5
6.99	847.6	4.8
10.44	851.5	5.1
17.33	858.5	5.6

of CO_2 or solvent. In the three cases of the isothermal model, the injection temperature is the same as the reservoir temperature. Fluids are injected at 49°C during the three other cases for the nonisothermal model. Table 7 lists the injection scenarios.

Table 5: Viscosity data for simulated oil and CO_2 mixtures at 59°C.

Dissolved gas mole fraction	Viscosity (mPa·s)
0.0058	3.15
0.158	2.45
0.412	1.44
0.439	1.34
0.521	1.05
0.595	0.79
0.641	0.65
0.826	0.18

3. Results

3.1. Effects of Injection Temperature and Composition. When the reservoir pressure is higher than the MMP, the injected fluids and crude oils are under the miscible condition. Figure 4(a) shows the pressure distribution versus distance for CO_2 injection at 82°C (Case 1). CO_2 injection starts on the 730th day and finishes on the 2,557th day. The reservoir pressure varies from 11 to 13 MPa. According to Figure 1, the MMP is 18.9 MPa for pure CO_2 injection at 82°C. In this

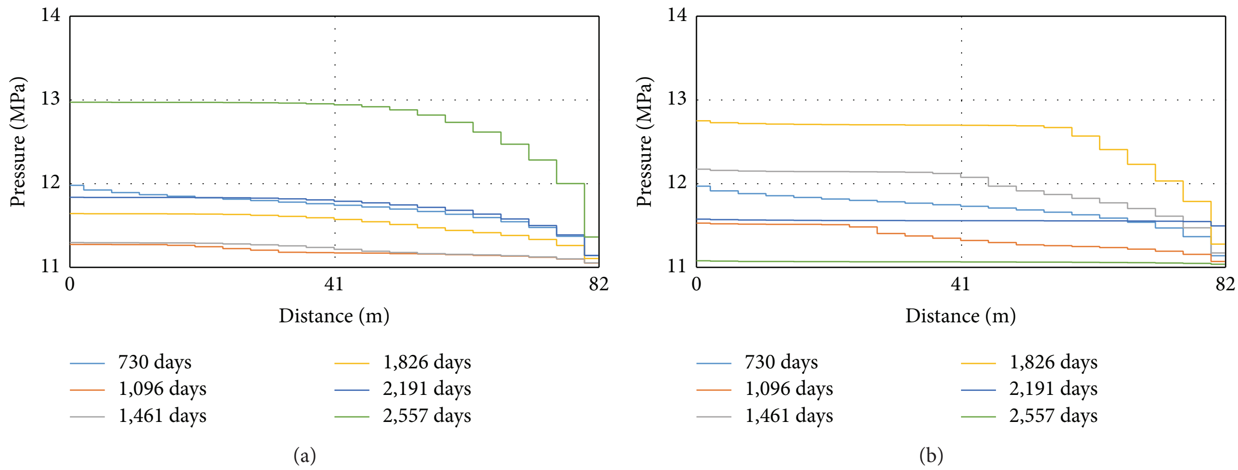

Figure 4: Pressure profiles between the injector and producer: (a) pure CO_2 injection at 82°C and (b) pure CO_2 injection at 49°C.

Table 6: Reservoir properties for the 2D, homogeneous, five-spot reservoir model.

Reservoir property	Value
Number of grid blocks	20 × 20 × 1
Thickness (m)	3
Grid block size (m)	3 × 3 × 3
Porosity	0.2
Permeability (m^2)	2.96×10^{-7}
Initial water saturation	0.2
Initial oil saturation	0.8
Initial reservoir temperature (°C)	82
Initial reservoir pressure (MPa)	13.8

Table 7: Temperature and composition data of the injected fluids.

Case	Temperature (°C)	Injection composition
1	82	CO_2 100%
2	82	CO_2 90% + LPG 10%
3	82	CO_2 80% + LPG 20%
4	49	CO_2 100%
5	49	CO_2 90% + LPG 10%
6	49	CO_2 80% + LPG 20%

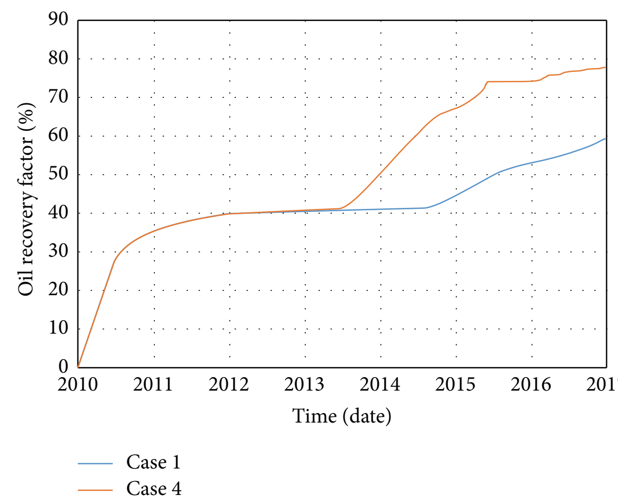

Figure 5: Oil recovery factors for the pure CO_2 injection case under isothermal (Case 1) and nonisothermal (Case 4) conditions.

circumstance, the injected fluids behave under the immiscible condition. Figure 4(b) illustrates the pressure profiles of CO_2 injection at 49°C (Case 4). The range of pressure distribution for this scenario is the same as in Case 1.

Figure 5 depicts the substantial improvement of oil recovery obtained by low-temperature CO_2 injection. For the immiscible case (Case 1), oil recovery is 59% at 1.0 PV CO_2 injection. The recovery factor of Case 4 is 78%, which is improved by 32% compared with Case 1. Figure 6 describes the temperature distributions from the injector to the producer as a function of time. Near the injector, CO_2 is always miscible with oil due to the temperature drop to 49°C. The area cooled by the low-temperature CO_2 injection has high CO_2 miscibility and low CO_2 MMP. This area becomes broader with time and a miscible region develops. According to Figure 7, more than 48% of CO_2 has dissolved into the oil phase in the miscible condition compared with the immiscible condition. The miscible condition, caused by the injected CO_2, leads to an improved displacement efficiency of the reservoir oil.

To examine the effect of CO_2 and LPG mixtures on oil recovery, two injection scenarios are implemented using two types of CO_2-LPG mixtures with proportions of 9 : 1 and 8 : 2 (Figure 8). If the concentration of LPG is above 10%, miscibility is achieved at 82°C; this is caused by the fact that the average pressure for all of the cases is under 13.8 MPa. In Case 2, a 1.0 PV slug mixture of CO_2 and LPG (9 : 1) is used, followed by waterflooding. The oil recovery by this mixture is 73% of the initial oil, which is about 22% higher than that of CO_2 flooding alone. In Case 3, the amount of LPG in

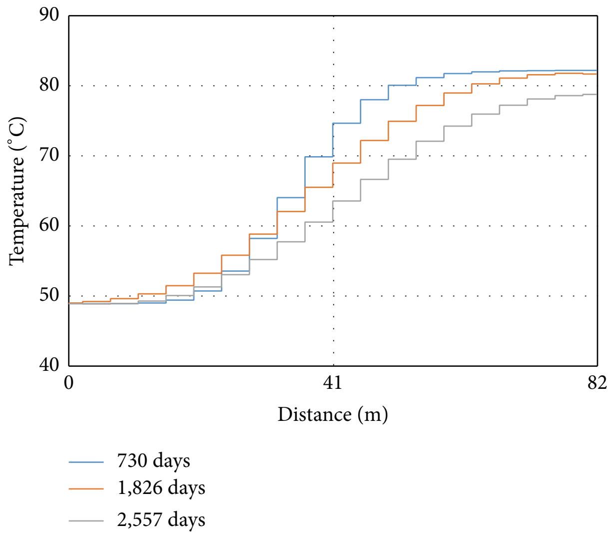

Figure 6: Temperature profiles from the injector to producer for Case 4.

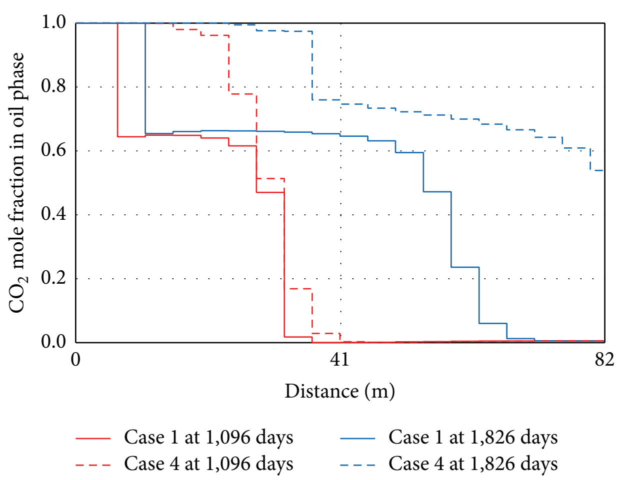

Figure 7: Mole fraction of CO_2 dissolved into the oil phase in the miscible and immiscible conditions.

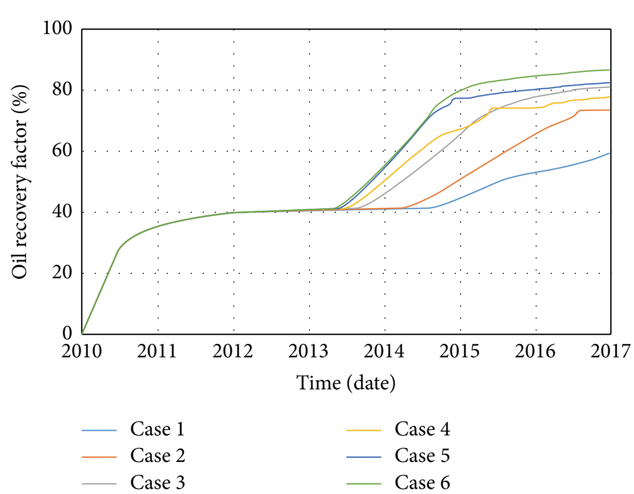

Figure 8: Oil recovery factors for all of the cases in the isothermal and nonisothermal conditions.

the mixture is increased to 0.2 mole fractions and the amount of CO_2 is reduced to 0.8 mole fractions. Using this mixture, 81% of the initial oil is recovered, which is about 35% more than the recovery obtained by CO_2 flooding.

Case 5 applies a 9 : 1 CO_2/LPG mixture injection at 49°C. The recovery obtained by this mixture is 82% of the initial oil. The recovery for this scenario is increased by as much as 5% compared with Case 4. When a CO_2-LPG mixture with a proportion of 8 : 2 is used at 49°C, the recovery is 87% of the initial oil. The increase in recovery obtained by this mixture is 12% higher than the recovery of Case 4. These improvements are caused by the considerable extension of the miscible areas due to the LPG mixture injection. The miscible zones of Cases 4 to 6 are illustrated in Figure 9. If the pressure is fixed at each grid block, the temperature is the main parameter that determines whether the conditions are miscible or immiscible. In the nonisothermal cases, the block pressures are close to 11 MPa after 1 PV CO_2 (or solvent) injection. At this pressure, miscible zones are developed under 54°C during pure CO_2 flooding and under 66°C during injection of the 10% LPG mixture. As a result, the miscible state occurs in 18% of the reservoir in Case 4 and 41% of the reservoir in Case 5. The whole reservoir becomes miscible in Case 6 due to the lower MMP caused by the mixture with 20% LPG.

3.2. Heat Transfer to/from Over/Underburden. Figure 10 compares the temperature profiles at 1.0 PV CO_2 injection. The temperature distribution varies with the effect of heat transfer between the reservoir and over/underburden. The average reservoir temperature drops to 81°C and 67°C in the models with and without heat transfer, respectively. In the heat transfer model, the temperature of the reservoir is maintained near the initial temperature.

The oil recovery factors for Cases 4 to 6 are demonstrated in Figure 11. This shows that the recovery factors from the simulations with the heat transfer model are lower than those of the original model without heat transfer. If pure CO_2 flooding is implemented with heat transfer, recovery is decreased by 12%. The recovery factors for the other two heat transfer models, which implemented CO_2-LPG mixture flooding, are also decreased by 4-5% compared with the original cases.

4. Conclusions

This study aims to examine the effects of CO_2 injection on oil recovery with respect to the temperature and composition. The MMP decreases in the cases of low-temperature and CO_2-LPG mixture injection. Miscibility is achieved within the swept zone despite the relatively low reservoir pressure. Performing a low-temperature injection provides significant improvements in terms of oil recovery. Even at elevated temperatures, the addition of LPG into the injected CO_2 is able to guarantee the reservoir performance by achieving miscibility. If heat transfer exists between the reservoir and surrounding formations, little change in the average temperature is obtained despite the injection of cool fluids.

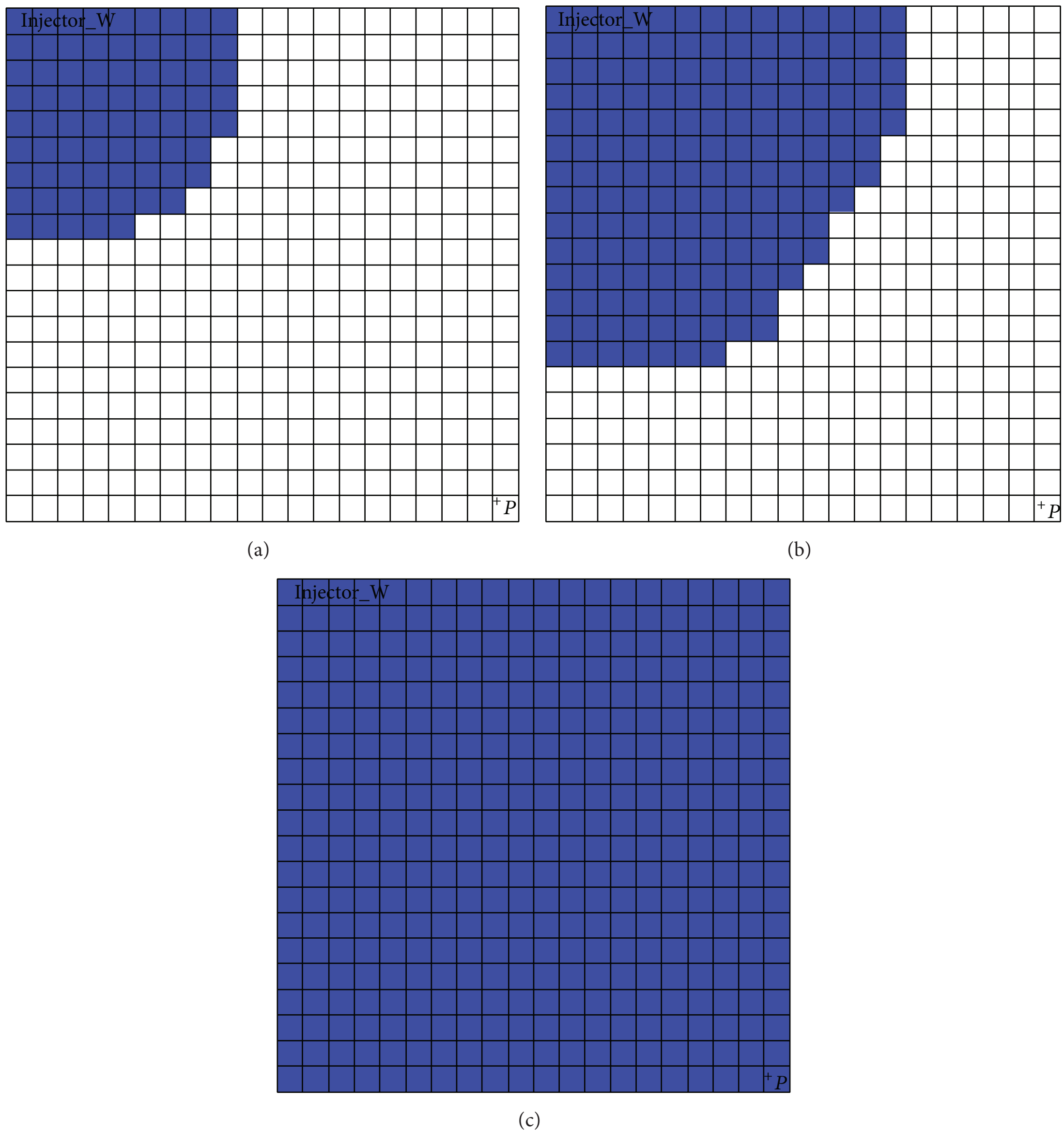

Figure 9: Miscible zones for nonisothermal cases after 1.0 PV CO_2 or CO_2/LPG injection: (a) Case 4, (b) Case 5, and (c) Case 6.

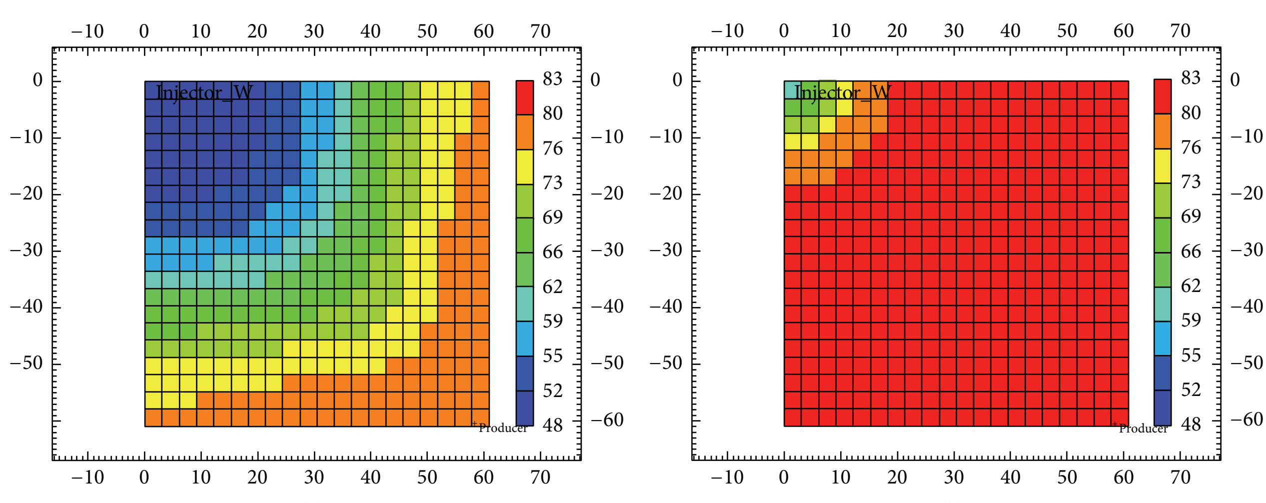

Figure 10: Temperature profiles at 1.0 PV CO_2 injection: (a) without heat transfer and (b) with heat transfer.

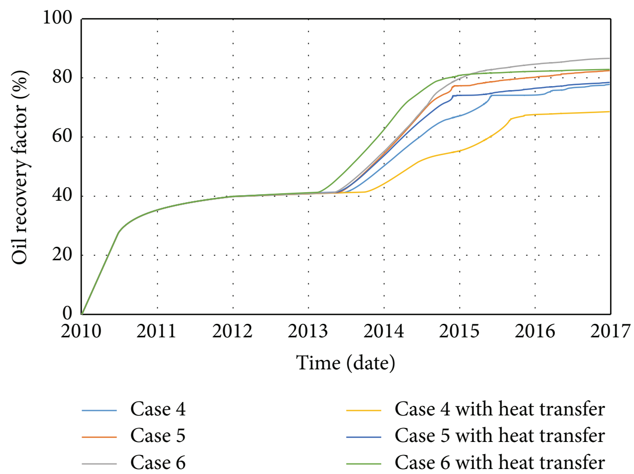

Figure 11: Oil recovery factors in the nonisothermal models with and without heat transfer.

However, in this model, recovery is enhanced in comparison to the isothermal models. This is caused by the fact that the area near the injector zone becomes miscible due to the cooling effects on the reservoir.

Conflict of Interests

The authors declare that there is no conflict of interests regarding the publication of this paper.

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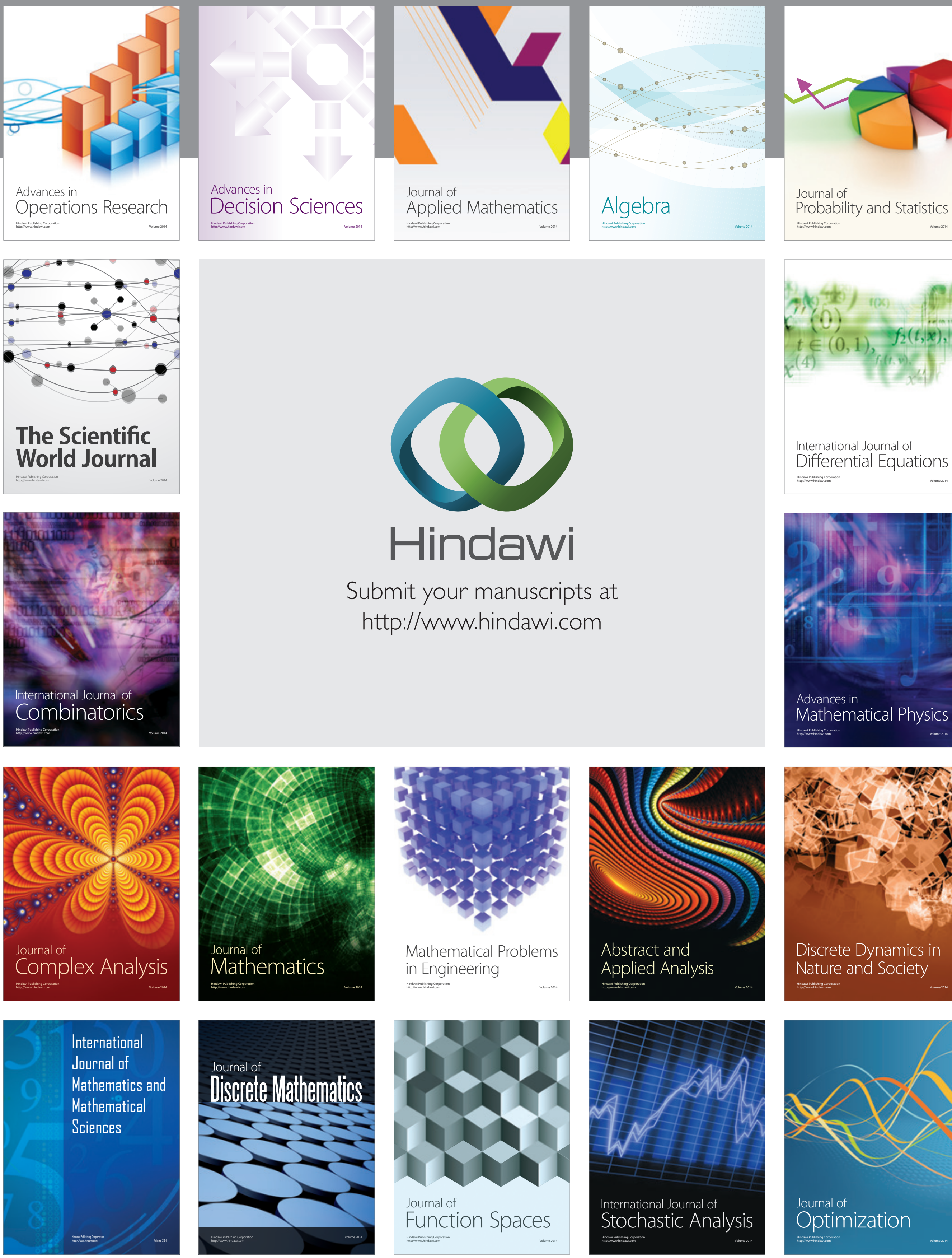
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