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Integrated Study of CO_2 Sequestration and CO_2-EOR in Oil Reservoir by Compositional Simulation

Mohammad Amirul Islam[1*] and A. S. M. Woobaidullah[2]
[1]*Department of PME, Military Institute of Science and Technology (MIST), Dhaka, Bangladesh*
[2]*Department of Geology, University of Dhaka, Dhaka-1000, Bangladesh*

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Abstract

Now researchers are performing extensive research work to increase the oil and gas production to meet increasing energy demand and to reduce the CO_2concentration from atmosphere to reduce global worming.This study is an effort to increase oil production by CO_2-EOR from an oil reservoir in Surma basin and to evaluate the oil reservoir as a candidate of CO_2 sequestration.

The oil reservoir rock is Bhuban sandstone and fluid is heavy oil. High salinity water is also present in the oil reservoir. A compositional reservoir simulation model has been developed for this study. Geo-cellular 3D reservoir grid structure has been constructed by block centered geometry. Reservoir rock properties such as porosity, absolute permeability and net to gross ratio have been modeled using rock properties of Bhuban sandstone. Reservoir oil composition has been determined from liquid chromatograph. Thermodynamic properties of pure components in reservoir oil have been included in the compositional reservoir simulation model. The reservoir has been developed by four CO_2 injection wells arranged at the periphery of the reservoir and one oil production well kept at the center of the reservoir. The optimum CO_2 injection rate is 500 MSCF/D at pressure 3100 psi by a single well and optimum oil production rate is 4900 STB/D.

Keywords: CO_2-EOR, CO_2 sequestration, Bhuban sandstone, Compositional reservoir simulation model, CO_2 injection mechanisms.

I. Introduction

Nowadays different techniques have been applied to enhance heavy oil recovery. One of the most widely applied techniques is CO_2 flooding for boosting heavy oil recovery. In heavy oil recovery, a depleting pressure scheme may be able to induce foamy oil flow, thus the oil recovery could be further enhanced. Different pressure control schemes were tested by 1-D core-flooding experiments to obtain an optimized one. Numerical simulations were conducted to history match all experimental data to understand the mechanisms and characteristics of different CO_2 flooding strategies.

The dissolution of CO_2 in crude oil results in the main factors that contribute to enhanced oil recovery. The solubility of CO_2 in oil depends on the pressure, temperature and characteristics of the oil. Increasing pressure increases the solubility and leads towards the saturation value[2].

As a result of CO_2 dissolution into the crude oil, the oil volume will increase from 10 to 60%. This phenomenon is greater for light oil and leads to lower residual oil saturation Holm, 1987[4]. Oil swelling increases the recovery factor for a given residual oil saturation increases, the mass of the oil remaining in the reservoir under standard conditions is lower than residual oil that has not had contact with the CO_2. CO_2 dissolution in crude oil also results in oil viscosity reduction. The kinetic stability of the emulsion formed in the mixed fluid may also be affected by the dissolution ofCO_2 and change the effective viscosity of the fluid as well[5].

CO_2 plays a vital role in extracting or vaporizing hydrocarbons from crude oil. When a lean injection gas passes over reservoir oil rich in intermediate components and extracts those fractions from the oil and concentrates at the displacement front where miscibility is achievedis termed as Vaporizing gas drive mechanism [6].

The transfer of intermediate components from rich solvent to intermediate-lean reservoir oil through condensation is known as condensing process. In CO_2 miscible flooding, the intermediates stripped from the oil that are present in the gas condense when the gas encounters fresh oil downstream[7].

Bhuban formation (Middle Miocene): Since no wells of the Sylhet structure so far penetrated the Lower Bhuban, the thickness of this formation cannot be ascertained. This zone mainly consists of very fine to medium grained, well

*Author for Correspondence. e-mail: mohamm1978@gmail.com

sorted, sub-angular to sub-rounded, calcareous sandstone. Inter-bedded grey shales are common with laminations of siltstone[1]. The palaeo-environment seems to have a persistent marine influence[1].

II. Characteristics of Reservoir Oil, Water and Rock

Reservoir oil composition has been estimated by liquid chromatograph in eleven component system shown in Table 1.

Table 1. Reservoir oil composition

Component Name	Formula	Mole Fraction in Reservoir Oil, ZI	Gas Phase Fraction	Liquid Phase Fraction
Carbon dioxide	CO_2	0.005	YMF1	XMF1
Nitrogen	N_2	0.006	YMF2	XMF2
Methane	C_1	0.050	YMF3	XMF3
Ethane	C_2	0.007	YMF4	XMF4
Propane	C_3	0.009	YMF5	XMF5
Iso-butane	IC_4	0.010	YMF6	XMF6
Butane	NC_4	0.010	YMF7	XMF7
Iso-pentane	IC_5	0.020	YMF8	XMF8
Pentane	NC_5	0.010	YMF9	XMF9
Hexane	C_6	0.023	YMF10	XMF10
Heptane+	C_{7+}	0.850	YMF11	XMF11

The reservoir water sample has been collected and tested in laboratory. The tests results have yielded that reservoir water has significant concentration of calcium Ca^+(0.09 mol/L) and magnesium Mg^+(0.144 mol/L) and high salinity (100000 ppm).

Clay contents in reservoir rock play important roles in oil recovery mechanism design[3]. Reservoir rock samples of Bhuban formation have been tested in laboratory by XRD study. Reservoir rock contains a good amount[3] of negatively charged surface clays such as Illite/Mica (1%), Chlorite (2%), Kaolinite (5%) and Montmorillonite.

III. Injected Gas Composition

Injected CO_2 may be from different sources such as natural CO_2 reservoirs and process plant waste streams. But whatever the source is: whether natural CO_2 reservoirs, process plant waste streams or produced gas from wells under CO_2 flooding, it always contain impurities. As cleaning up of the recycling gas produced from wells under CO_2 flooding is costly produced gas is always re-injected without purification. Major components of impure CO_2 are nitrogen, H_2S, and hydrocarbons. Recycling gas produced from wells under CO_2 flooding contains methane (CH_4), nitrogen, H_2S, and intermediate hydrocarbons (C_2 - C_4), presence of which may affect the pressure required to achieve miscible displacement. In this study injected gas contains 94.1% of CO_2 as shown in Table 2.

IV. Compositional Reservoir Simulation Model

The studied reservoir is located in the Surma basin (Haripur oil field) and the reservoir rock is Bhuban sandstone. Reservoir fluids are oil and brine. Oil-water contact has been detected at depth of 6660 ft and reservoir top has been detected at depth of 6000 ft.

Table 2. Injected gas composition

Component Name	Formula	*Mole Fraction in Injection Gas*	*Gas Phase Fraction*	*Liquid Phase Fraction*
Carbon dioxide	CO_2	0.941	YMF1	XMF1
Nitrogen	N_2	0.031	YMF2	XMF2
Methane	C_1	0.028	YMF3	XMF3
Ethane	C_2	0.0	YMF4	XMF4
Propane	C_3	0.0	YMF5	XMF5
Iso-butane	IC_4	0.0	YMF6	XMF6
Butane	NC_4	0.0	YMF7	XMF7
Iso-pentane	IC_5	0.0	YMF8	XMF8
Pentane	NC_5	0.0	YMF9	XMF9
Hexane	C_6	0.0	YMF10	XMF10
Heptane+	C_{7+}	0.0	YMF11	XMF11

Aquifer exists below the oil-water contact and the aquifer bottom has been detected at depth of 8000 ft. The reservoir has 660 ft thick oil zone and 1340 ft thick water zone. A compositional reservoir simulation model of the real reservoir (Bhuban sandstone) has been developed to study the CO_2-EOR and CO_2 sequestration.

A cubic shape geological body of the whole oil reservoir has been considered for the study. Geo-cellular grid structure of reservoir has been constructed by block centered geometry method as shown in figure 1. The reservoir structure has been divided into 30 grid cells of dimension 100 ft in the X direction. In the Y direction reservoir structure has been divided into 30 grid cells of dimension 100 ft and reservoir structure has been divided into 20 grid cells of dimension 100 ft along the depth (Z direction).

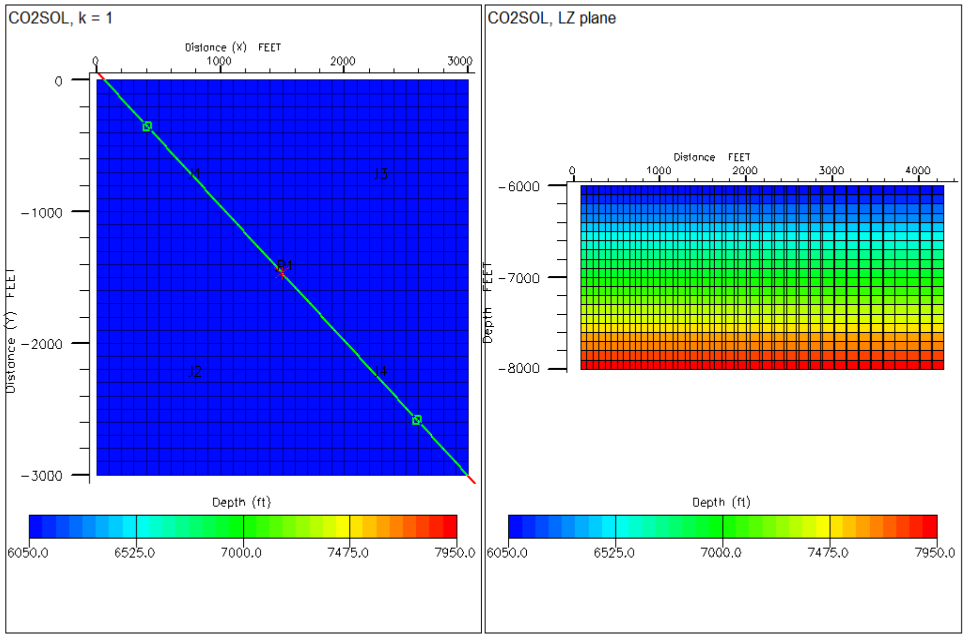

Fig. 1. Geo-cellular grid structure of reservoir

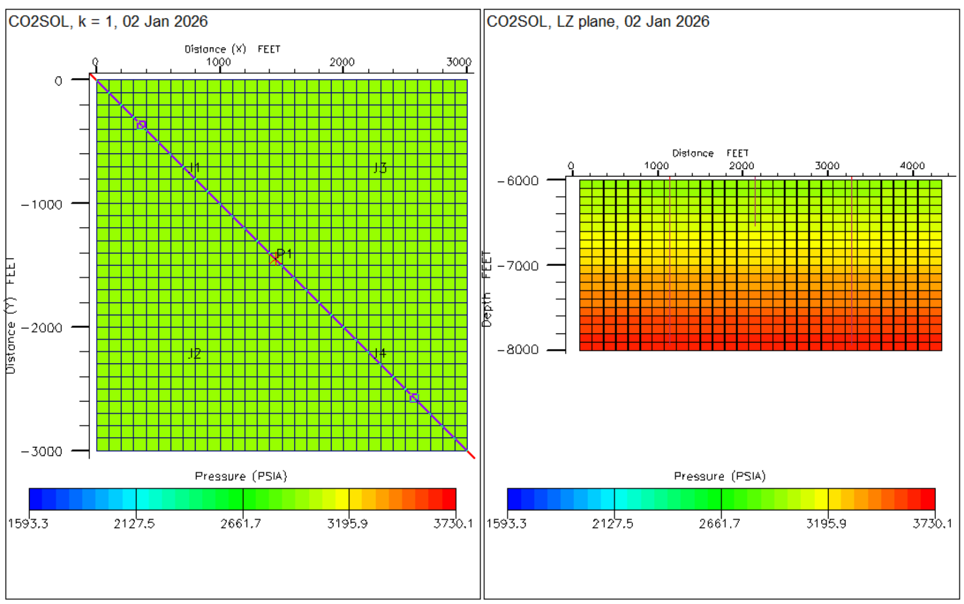

Fig. 2. CO_2 injection and oil production wells

Porosity of Bhuban sandstone has been determined in laboratory by mercury injection porosimeter. Ten core plugs of Bhuban sandstone have been prepared to determine the absolute permeability by liquid permeameter. The estimated porosity and absolute permeability have been used to distribute porosity and absolute permeability in the geo-cellular grid model of reservoir by sequential Gaussian simulation. Net to gross ratio has been distributed in the geo-cellular grid model of reservoir.

Equation of state (EOS) of compositional simulation model is Peng-Robinson and its parameters have been included in the simulation model. Thermodynamic propertied of pure components have been included in the compositional reservoir simulation model. Oil-water relative permeability and capillary pressure in Bhuban sandstone have been determined by relative permeability meter and capillary pressure meter respectively. Oil-water relative permeability and capillary pressure have been measured as a function of water saturation. Tabular form of oil-water relative permeability and capillary pressure as a function of water saturation has been included in the compositional reservoir simulation model. The reservoir pressure has been predicted as 3000 psi at depth of 6000 ft. Four CO_2 injection wells have been placed at the periphery of the reservoir and one oil production well has been placed at the center of the reservoir. The compositional reservoir simulation model has been simulated from 01 January 2026 to 01 January

2050. The predictions of the compositional simulation (Eclipse 300) have been analyzed to evaluate the technical feasibility of CO_2-EOR and CO_2 sequestration in the oil reservoir. Total reservoir pore volume is 512.946 million barrels. Thermodynamic behavior of a component is dependent on the temperature and pressure of the reservoir. The reservoir temperature is 190^o F and pressure is 3000 psi[2]. Compositional simulator simulates the thermodynamic behavior of a component and the development of phases such as oil phase and gas phase in the reservoir by equation of state (EOS). Composition of a component in oil phase, gas phase and water phase is also determined by the compositional simulator. The states of injected CO_2 gas, reservoir oil and reservoir water are defined by the compositional simulator. Physical properties of fluid phases such as gas phase, oil phase and water phase in the reservoir change with CO_2 injection as compositions of fluid phases in the reservoir change with CO_2injection. Viscosity and density of fluid phases in the reservoir change with CO_2 injection.

V. Mechanism of CO_2 injection

In the compositional reservoir simulation model CO_2 injection wells have been placed at the four corner of the reservoir and one oil production well has been placed at the center of the reservoir as shown in figure 2. CO_2 has been injected at the rate of 500 MSCF/D by each CO_2 injection well and oil has been produced at the rate of 4900 STB/D by the single well. The CO_2injection pressure is 3100 psi at surface and the reservoir pressure is 3000 psi at the depth of 6000 ft.

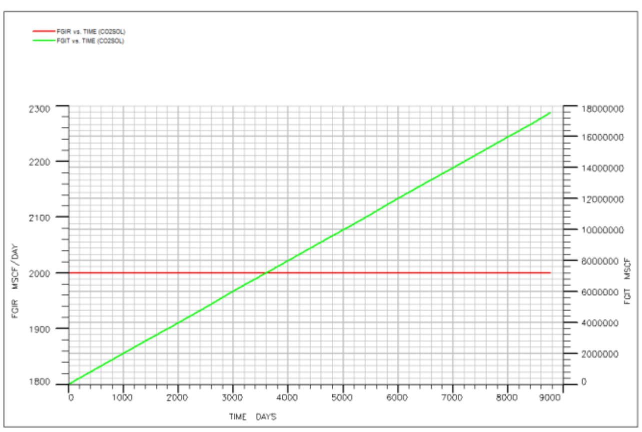

Fig. 3. CO_2 injection rate and total CO_2 injected

CO_2 has been injected in the both oil zone and water zone. Oil has been produced from the oil zone. Reservoir oil composition and its properties change by the injected CO_2. Dynamic behavior of reservoir also improves by the injected CO_2. 2000 MSCF CO_2 has been injected per day in the reservoir by four injection wells. Total 17.53 BCF CO_2 has been injected into the reservoir as shown in figure 3. Some portion of injected $CO_2$is dissolved in the reservoir oil and some portion of injected $CO_2$is dissolved in the reservoir water phase. Un-dissolved CO_2 remains in the gaseous phase. Dissolved CO_2 contributes in miscible oil displacement while un-dissolved CO_2 contributes in immiscible oil displacement.

VI. Reduction of Oil Viscosity

The injected CO_2 dissolved in the reservoir oil reduces oil viscosity. Initially the oil viscosity was 0.272 cp. After 9000 days of CO_2 injection the oil viscosity is reduced to 0.224 (Fig. 4). The dissolution of the gaseous CO_2 in the liquid oil phase has reduced the oil viscosity as a natural phenomenon. The simulator has quantified the initial oil viscosity and the oil viscosity after dissolution of CO_2. The oil viscosity has reduced by 17.64% which increases the mobility of oil.

VII. Miscible and Immiscible Displacement

In the simulation study CO_2 has been injected continuously for the 9000 days at a constant rate. The CO_2 has gradually dissolved in oil phase and water phase (Fig. 5).

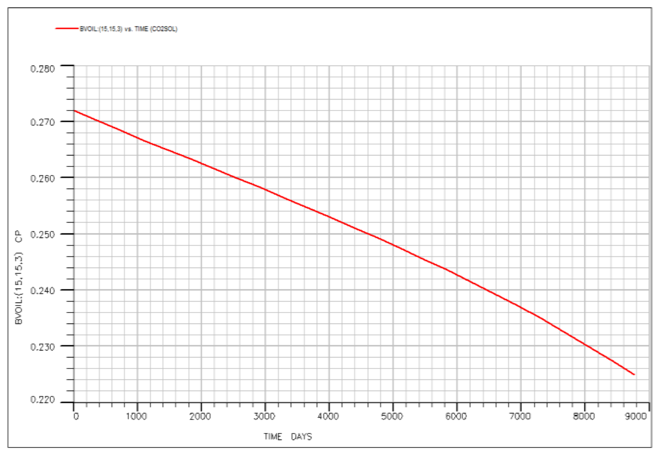

Fig. 4. Oil viscosity profile with time

Fig. 5 shows maximum CO_2 concentration in water phase and in oil phase is 86% and 65% respectively. Solubility of CO_2 in water phase is more than that of in oil phase. Concentration gradient of CO_2 is developed in the both oil and water phases. The maximum radius of CO_2 concentration gradient is approximately 700 feet. The gradually dissolved CO_2 in oil phase has reduced the oil viscosity and increased oil mobility. Dissolved CO_2derived from the oil phase of the production well has been formed by miscible displacement mechanism.

Initially the reservoir has only oil and water phases and gradually gas phase has been developed by the CO_2 injection (Fig. 6). Some portion of the injected CO_2 is remained un-dissolved and formed gas phase. The un-dissolved CO_2 remained in the oil phase moved to the production well by immiscible displacement mechanism.

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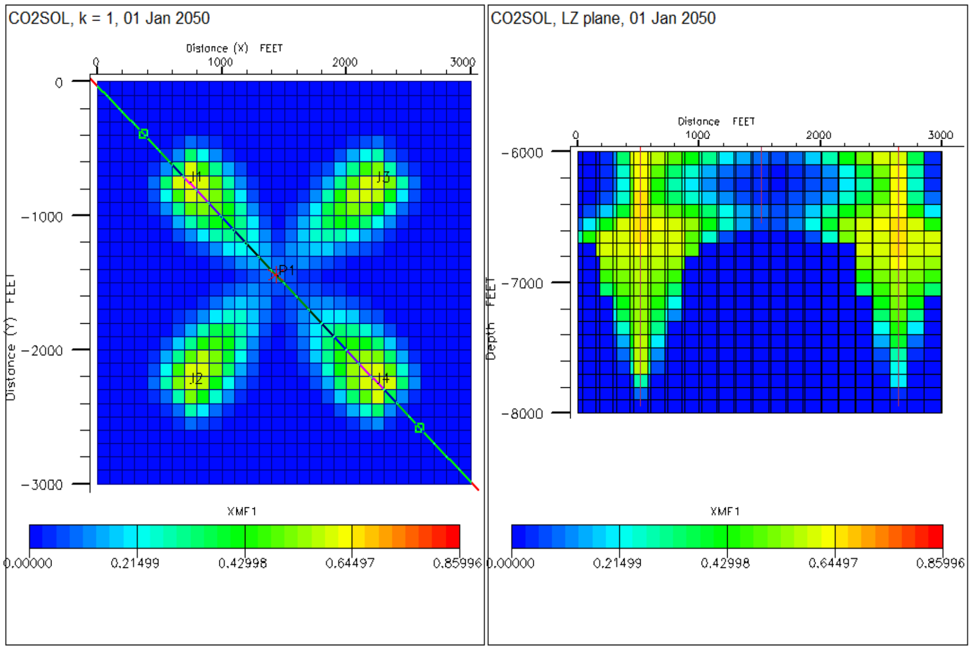

Fig. 5. CO_2 concentration in oil and water phases after 9000 days of simulation

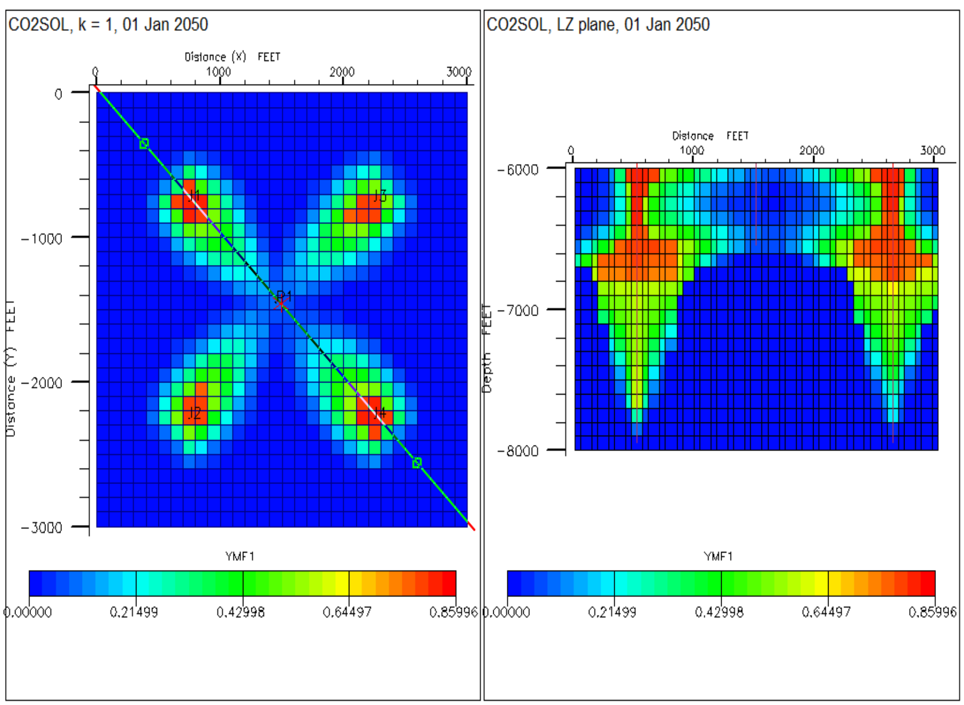

Fig. 6. CO_2 concentration in gas phases after 9000 days of simulation

remained un-dissolved and formed gas phase. The un-dissolved CO_2 remained in the oil phase moved to the production well by immiscible displacement mechanism.

VIII. Dissolution of CO_2 in Reservoir Oil and Water

The injected CO_2 is dissolved in the both oil and water phases (Fig. 7). Maximum quantity of CO_2 is dissolved in reservoir water phase rising to 86.79%. Good quantity of CO_2 is also dissolved in reservoir oil phase leading to 75.42%. CO_2 concentration gradient is developed in the oil and water zones along the reservoir cross section (LZ plane). CO_2 concentration near the well bore is the maximum and gradually decreases with distance from the well bore. In the oil phase the maximum CO_2 concentration is 75.42% near at the well bore and the minimum is 38.00% at 1300 ft away from the well bore.

In the water phase the maximum CO_2 concentration is 86.79% near at the well bore and the minimum is 36.28% at

1100 ft away from the well bore.CO_2has been sequestrated in the reservoir by dissolution of CO_2in oil and water phases as well as trapping of CO_2 as gaseous phase in the reservoir pore space.

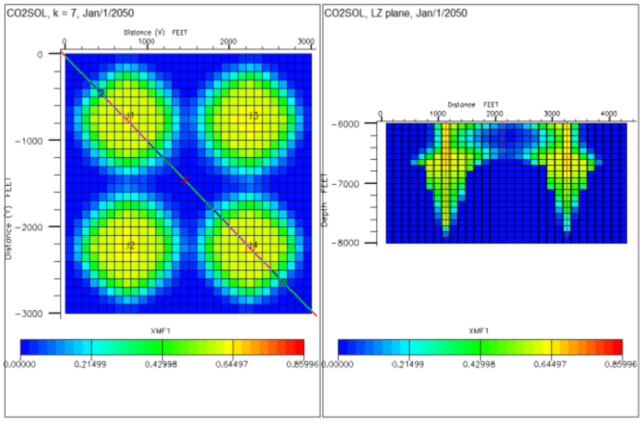

Fig. 7. Dissolution of CO_2 in reservoir oil and water phases

IX. Oil Recovery

Oil production rate remains constant at 4900 STB/D for 9000 days (Fig. 8). Oil production and recovery factor are increasing with time while field oil in place is decreasing with time. Simulation study shows that recovery factor can be enhanced by 30% through CO_2 injection.

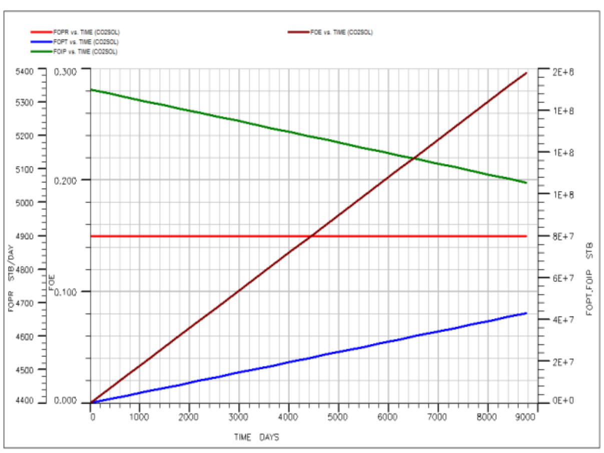

Fig. 8. Oil production profile

X. Conclusions

Carbon dioxide (CO_2) as a greenhouse gas has negative impacts on climate change. Storage of CO_2 in hydrocarbon reservoirs may be one of the options to reduce the amount of greenhouse gas in the atmosphere to mitigate the negative impact. CO_2 injection to the hydrocarbon reservoirs through proper designing mechanisms on the other hand may enhance the recovery of hydrocarbon from the reservoir. The static and dynamic behavior of CO_2 in these storage sites located at various depths, geology and geographical locations, affect the efficiency of this strategy.

The chemical properties of reservoir oil, water and rock have been analysed to design the proper CO_2 injection mechanism. Impure CO_2 gas is considered to be injected into the reservoir as purification of CO_2 is very costly. Enhanced oil recovery has been achieved by reduction of oil viscosity and increasing of oil mobility. The both miscible and immiscible displacement mechanisms plays role to derive the oil phase to the production well. Simulation study forecasted that the oil recovery factor can be enhanced by 30%. The study also showed that total 17.53 BCF impure CO_2 gas of 94.1% purity has to be injected into the reservoir. Impure CO_2injected has been sequestrated in the reservoir by dissolution of CO_2in oil and water phases as well as trapping of CO_2 as gaseous phase in the reservoir pore space.

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