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Maximizing Oil Recovery for CO_2 Huff and Puff Process in Pilot Scale Reservoir

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ABSTRACT

A pilot scale simulation is performed for enhanced oil recovery by CO_2 injection to M field in Indonesia. CO_2 stimulation (Huff and Puff) method is considered as one of the most successful processes to increase oil recovery. Prior to the CO_2 injection, water is injected to support an additional reservoir pressure. 1,000 tons of CO_2 are injected into M-19 well for 50 days. After 30 days of soaking, production is resumed and continued for 10 years. Cumulative oil recovery from Huff and Puff process is increased by 2% compared with primary production, mainly due to viscosity reduction observed near the well. The oil viscosity near the wellbore is reduced by 26% due to the dissolved CO_2 gas.

To maximize the oil recovery from CO_2 Huff and Puff process, the operating conditions are optimized. The design parameters include water injection rate, CO_2 injection rate, water injection time, and soaking time. Through optimization based on DECE, the oil recovery is increased by 12% and 9.8% compared with primary production and stimulated case without optimization, respectively. The oil viscosity decreases by 70% though CO_2 soaking area is smaller than that of non-optimized case. This study shows that CO_2 Huff and Puff method has a potential to improve oil recovery and optimized operating design is needed to produce more oil.

1. INTRODUCTION

As one of the CO_2 enhanced oil recovery (EOR) methods, CO_2 stimulation method, so-called Huff and Puff method, has achieved significant success in many field projects. In the Huff and Puff technique, single well is used as both injector and

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producer. It follows three steps such as gas injection, shut-in for soaking time, and re-open to produce.

During 1984 and 1985, CO_2 Huff and Puff projects were implemented to 11 wells for five fields in South Louisiana. Total 78,822 bbl of incremental oil were produced from these projects through April 1986 as the result of CO_2 injection (Palmer *et al*. 1986).

In Camurlu field in Turkey, immiscible CO_2 Huff and Puff pilot project on two wells started in December 1984 and continued till December 1986. Three cycled CO_2 stimulation was applied to two different fields (Camurlu-11 and Camurlu-22) in 1984. Average production rate was 18.3 STB and cumulative oil recovered for each cycles are 2,043, 4,382, and 7,212 bbl (Gondiken 1987).

In Timbalier Bay field in US, well 271 and 272 drilled in 1977 on two structural highs. Due to the poor sweep and completion efficiencies, CO_2 stimulation was applied on the two wells. During the first production period, the well flowed at a maximum rate of 111 bbl/D and production peaked at 190 bbl/D during second phase. Total production for the combined test period was 5,034 bbl (Simpson 1988).

For Big Sinking field in US, the 203 treatments with 85,000 Mscf of CO_2 was performed in 1985. The composite efficiency is 0.83 Mscf/bbl yielding a total incremental recovery from the CO_2 stimulation of 102,000 bbl (Miller 1990).

The first Huff and Puff project in Trinidad and Tobago was conducted in 1984 in the Forest Reserve oilfield. CO_2 was easily accessed from nearby immiscible floods. A total of 2,092 MMcf of CO_2 was injected and 101,635 bbl of oil recovered from the 16 wells tested (Mohammed-Singh *et al*. 2006).

Based on fluid modelling and compositional simulation, CO_2 Huff and Puff process is simulated for M field in Indonesia. Fluid modelling for numerical simulation is conducted with Peng-Robinson equation of state. Reservoir is subtracted around target well, M-19, to describe pilot scale simulation. Results are compared with those from primary recovery regarding recovery factor, cumulative WOR, and GOR. The simulation is to examine the efficiencies of Huff and Puff process for improving oil recovery. Then, Huff and Puff process is optimized to maximize oil production. Operation conditions such as injection rate and soaking time are considered as design parameters for optimization. These results show the necessity of optimization for the efficient implementation of the Huff and Puff process in pilot scale.

2. CO_2 HUFF AND PUFF PROCESS

2.1 Mechanisms

The main mechanisms of oil recovery during cyclic CO_2 stimulation include oil swelling, viscosity reduction, and relative permeability shifts due to the displacement of moveable water by a gas. A CO_2 Huff and Puff is comprised of gas injection, a soak period where the well is shut-in, and a production stage.

During the injection stage, the injected CO_2 remains immiscible and bypasses the oil, either by displacing moveable water or oil. Some moveable water saturation is desirable as it can prevent oil from being displaced away from the wellbore. By the end of the injection stage, the CO_2 is dispersed throughout the reservoir and mass transfer between the CO_2 and crude oil occurs. The reservoir pressure at the end of the injection cycle is also significantly higher than pressure at the beginning, which is an aid to miscibility although it is desired that displacement does not occur during injection.

During the soak period, the mass transfer between crude oil and CO_2 occurs. The oil phase swells in volume and intermediate hydrocarbons are extracted into the CO_2. The delayed miscibility conditions requires the soak period although the recommendations in the literature for the length of soak can vary considerably.

In the production stage, oil production occurs as a result of oil swelling, viscosity reduction, extraction, lower IFT (interfacial tension), and relative permeability shifts due to the displacement of the moveable water by CO_2. Oil swelling occurs throughout the contacted region rather than at the flood front as in a continuous flood, and the relative permeability of the oil is increased as a result. The lower viscosity and IFT also enhances the oil migration more easily (Murray et al. 2001).

2.2 Parameters

As the number of CO_2-stimulated wells increases, a number of researches are in progress for applicability and real application cases (Palmer *et al*. 1986; Monger and Coma 1988; Haskin and Alston 1989). According to these studies, CO_2 stimulation can enhance oil recovery by expelling residual oil from the reservoir. Moreover, a lot of studies bear on key parameters, which influence CO_2 stimulation performance, have been proceeded (Patton *et al*. 1982; Hsu and Brugman 1986; Thomas and Monger-McClure 1991). Patton *et al*. (1982) performed simulation for heavy oil reservoir and ascertained the amount of injected CO_2 and numbers of cycles are the most important parameters. Based on real field data of Louisiana reservoir, Hsu and Brugman (1986) reported that injected CO_2 volume is the most influence parameter for oil recovery but soaking time does not affect so much.

Treatment pressure is the maximum reservoir pressure which is permitted during injection. High treatment pressure results in higher CO_2 solubility and lower oil viscosity. Injection pressures as high as 0.7 psi/ft of depth have been used in several field tests with good results (Patton *et al*. 1982). The faster CO_2 injection into the well causes the further CO_2 fingering throughout the reservoir, thus contacting more oil (Palmer *et al*. 1986).

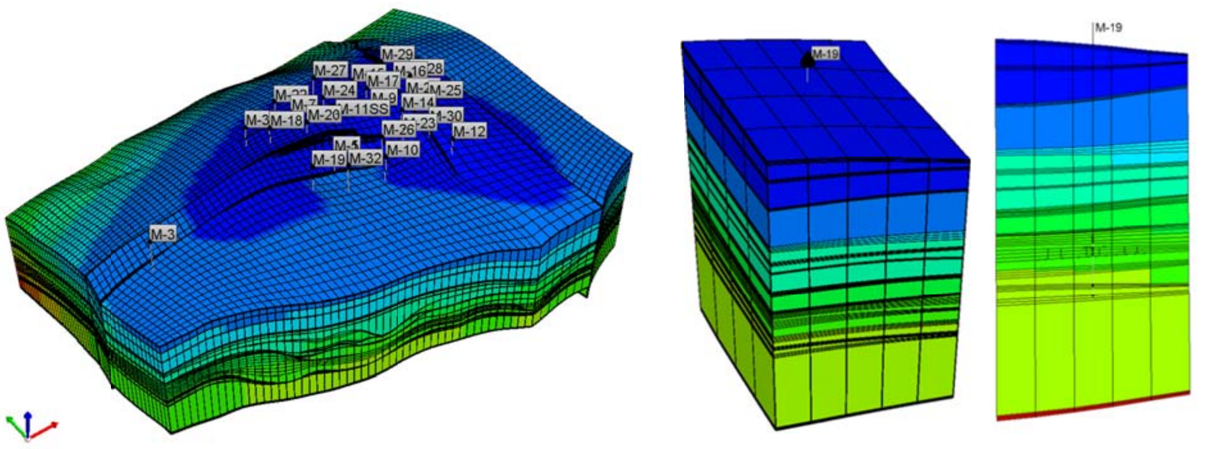
Injected CO_2 volume has been known as one of the most effective parameters to improve oil recovery. . According to Thomas and Monger-McClure (1991) investigating 14 reservoirs that CO_2 stimulation was performed in Louisiana and Kentucky, the amount of injected CO_2 was the most significant key parameter not only in heavy oil reservoir but in light oil reservoir. Due to the larger contact volumes between the injected CO_2 and oil, the effects of swelling and oil viscosity reduction increased oil recovery.

Also, soaking time affects the CO_2 stimulation performance. During the injection cycle, some oil is displaced away from the wellbore, requiring re-saturation by returned oil flow before stimulated oil production can be obtained. Although soaking time is necessary to maximize oil recovery, the length of soak period is not significant (Hsu and Brugman 1986).

3. SIMULATION RESULTS

3.1 Huff and Puff Base Model

Fig. 1(a) shows entire reservoir model of M field in Indonesia. The target well, M-19, is located near one of faults. To examine the effect of Huff and Puff process, area around the target well is subtracted and used as base model. Fig. 1(b) describes the base model and its cross section. Permeability for 5-c layer, where the CO_2 is injected, ranges from 120 to 1,000 md. Oil composition and PVT data are indicated in Table 1 and Figs. 2~4. Figure 2 shows the well matched results between experimental and simulated data. Based on the results, constant composition expansion and differential liberation results are represented in Figures 3 and 4. History match has been already applied up to July 01, 2010 and the simulation is performed to forecast the performance until July 01, 2020.

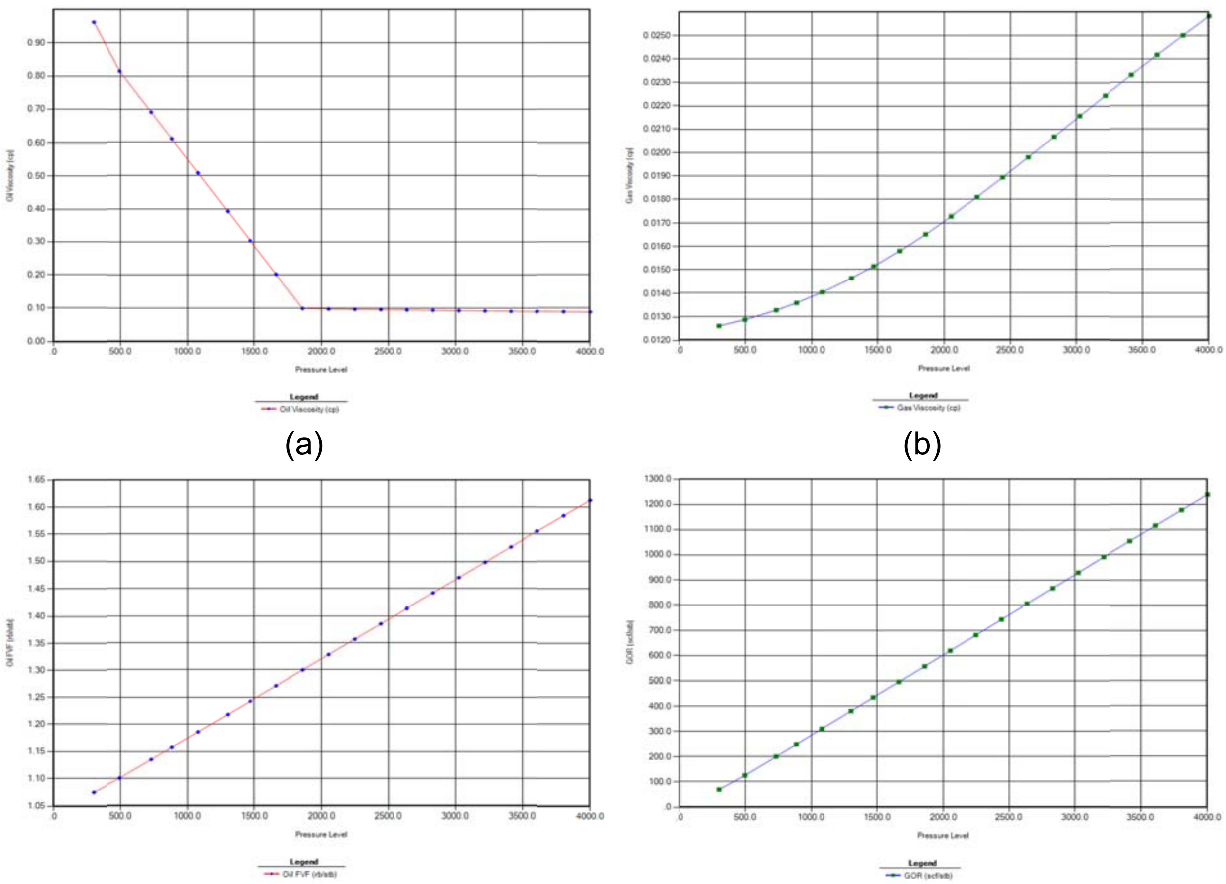


(a) (b)

Fig. 1 Reservoir model of M field in Indonesia: (a) full model, and (b) subtracted model.

Table 1. Oil composition for simulation.

Component	Mole Fraction
CO_2	0.0006
N_2	0.0039
CH_4	0.1388
C_2H_6	0.0175
C_3H_8	0.0405
IC_4	0.0165
NC_4	0.0306
IC_5	0.0167
NC_5	0.0157
FC_6	0.0270
C_{7+}	0.6922
Sum	1



(a) (b) (c) (d)

Fig. 2 Experimental data for PVT modelling: (a) oil viscosity, (b) gas viscosity, (c) oil formation volume factor, and (d) gas oil ratio.

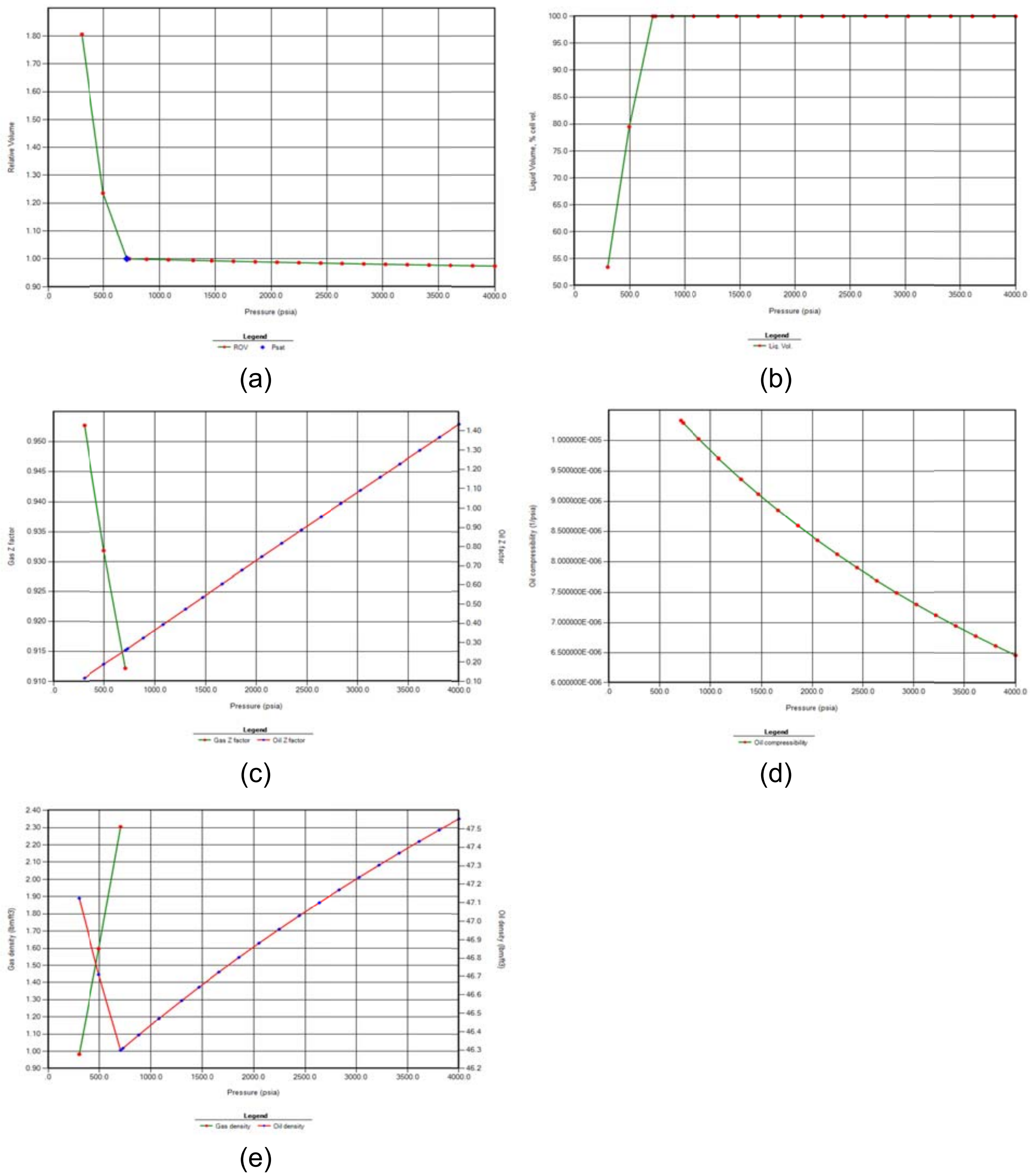
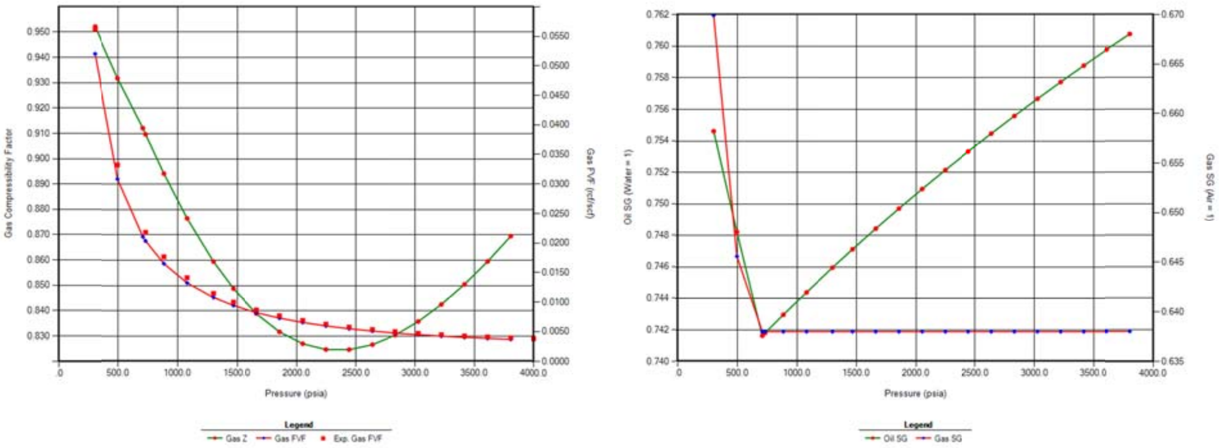


Fig. 3 Results from CCE (constant composition expansion) for PVT modelling: (a) relative oil volume, (b) liquid saturation, (c) gas compressibility factor below saturation pressure and oil compressibility factor above and below saturation condition, (d) oil compressibility, and (e) oil and gas densities.



(a) (b)

Fig. 4 Results from DL (differential liberation) for PVT modelling: (a) gas compressibility factor and gas formation volume factor, and (b) specific gravities of oil and gas.

Fig. 5 indicates time-line of well events for base case. Production period is represented by black line. Water injection and CO_2 injection are represented by blue and red line, respectively. Water is injected by 300 bbl/D for 30 days and CO_2 is injected by 20 tons/D for 50 days (Fig. 6). Total amount of injected CO_2 is fixed by 1,000 tons and soaking time is 30 days (Table 2). BHP (bottom hole pressure) of production well is set to be 500 psi.

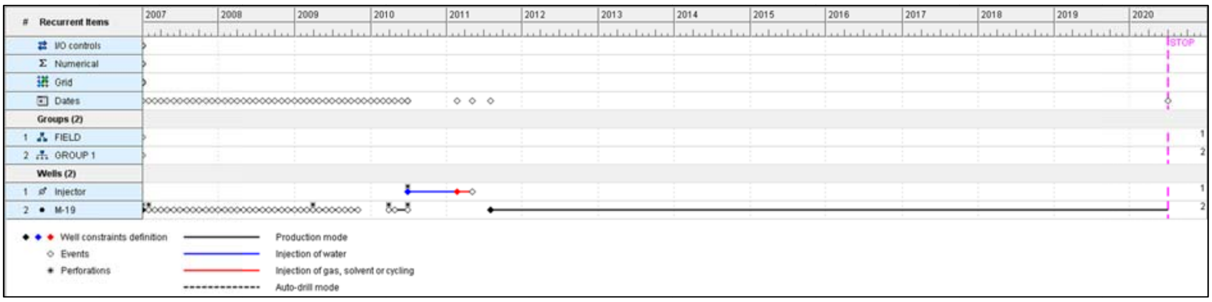


Fig. 5 Time-line of well events.

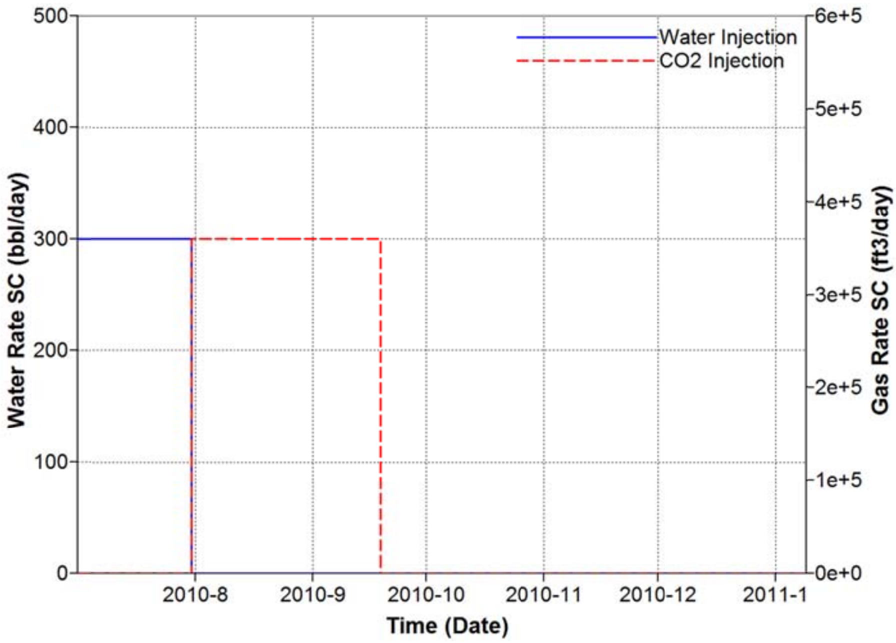


Fig. 6 Schedule for water injection and CO_2 injection.

Table 2. Design parameters of base case.

Parameters	Value
Water Injection Rate	300 bbl/D
CO_2 Injection Rate	20 tons/D
Water Injection Time	30 days
CO_2 Injection Time	50 days
Soaking Time	30 days

In comparison with primary recovery case, Huff and Puff process has no advantage in oil production at early time (Fig. 7). Injected to increase reservoir pressure, the water disturbs flow of oil. However, the oil rate of primary case is sharply decreased and showed reversed rate compared with Huff and Puff case, as shown in Fig. 7(a). Fig. 7(b) indicates that cumulative oil recovery of Huff and Puff case is improved by 2%. Oil saturations at the end of simulation are depicted in Fig. 8. Cumulative WOR and GOR are described in Fig. 9. In comparison with primary recovery case, cumulative WOR of Huff and Puff case is slightly increased. Cumulative GOR of Huff and Puff case is increased by 33%.

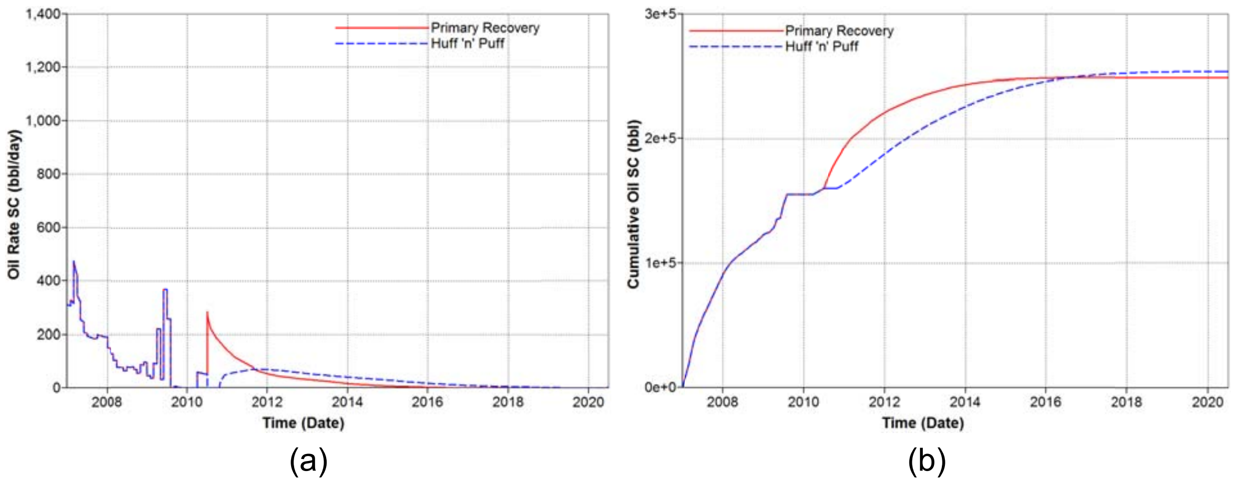


Fig. 7 Oil production for primary recovery and Huff and Puff case: (a) oil rate, and (b) cumulative oil.

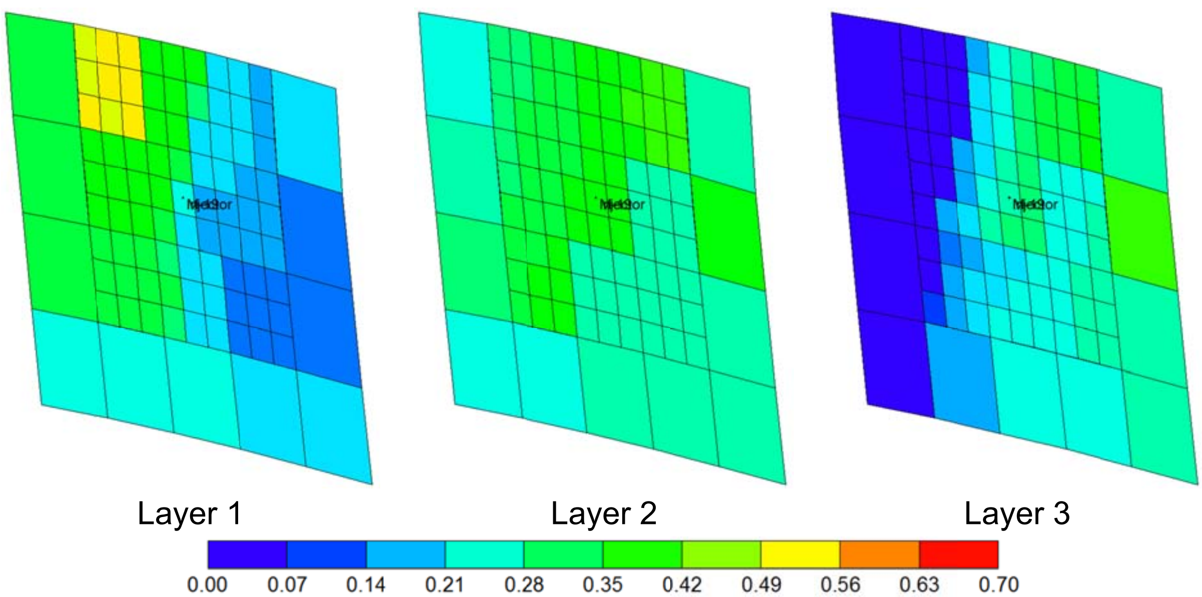
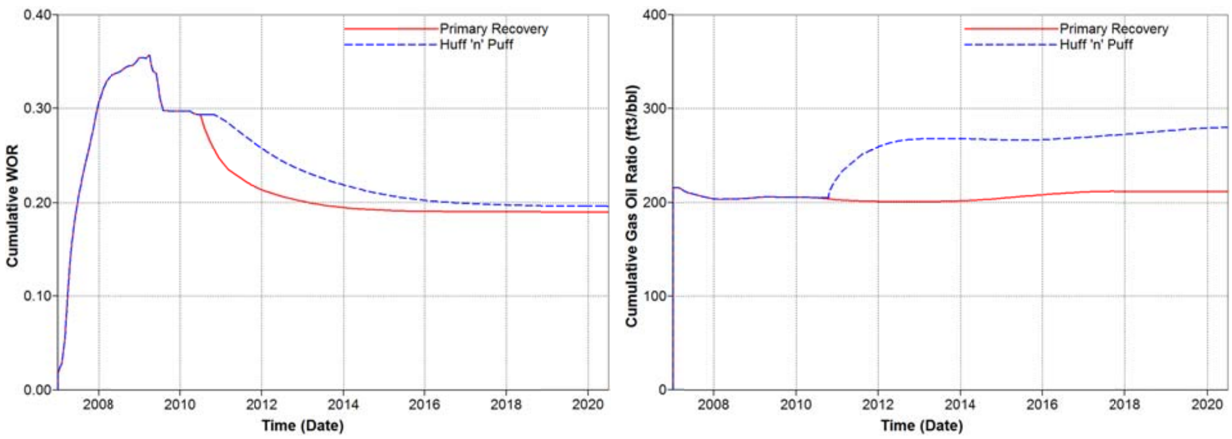


Fig. 8 Oil saturation at the end of simulation.



(a) (b)

Fig. 9 Cumulative WOR and GOR of primary recovery and Huff and Puff process: (a) cumulative WOR, and (b) cumulative GOR.

Fig. 10 shows that the CO_2 mole fraction at the soaking time. Differences of mole fraction profiles between each layer result from light density of CO_2. Most of CO_2 is migrated to upward (Layer 1) and little of CO_2 remains at near well bore in Layer 3. Cross-sectional distribution clearly shows gravity overriding effect (Fig. 11). Injected CO_2 has ability to swell the oil and this effect induces the viscosity reduction (Fig. 12). The oil viscosity is reduced by 26% due to the CO_2 dissolving. The viscosity reduction is one of the main mechanisms to enhance oil recovery.

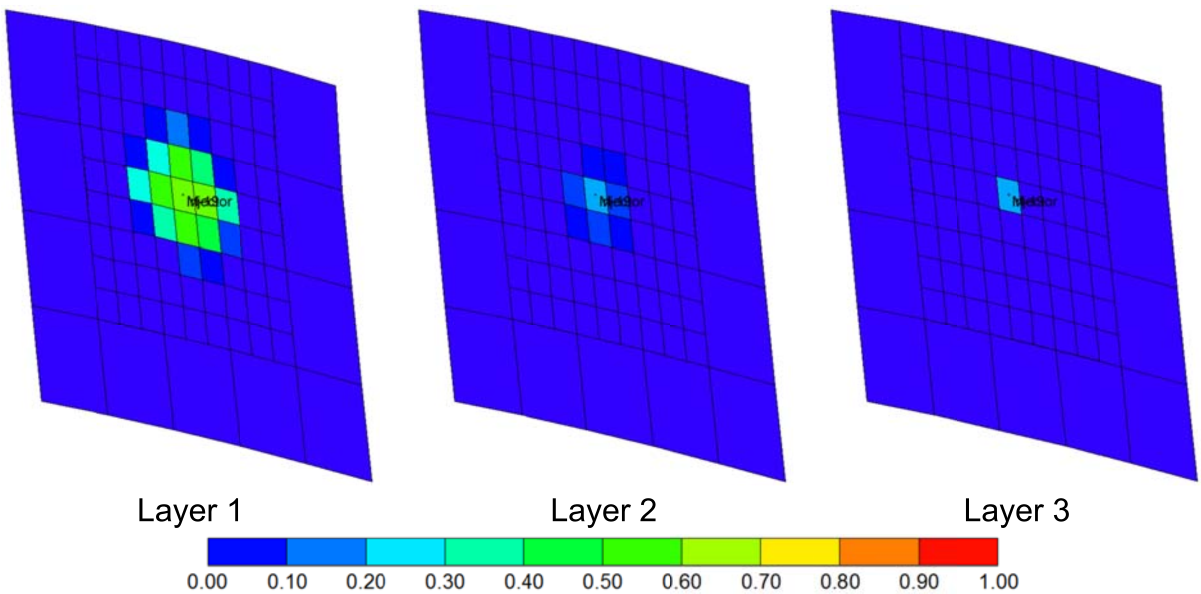


Fig. 10 CO_2 mole fraction at soaking time.

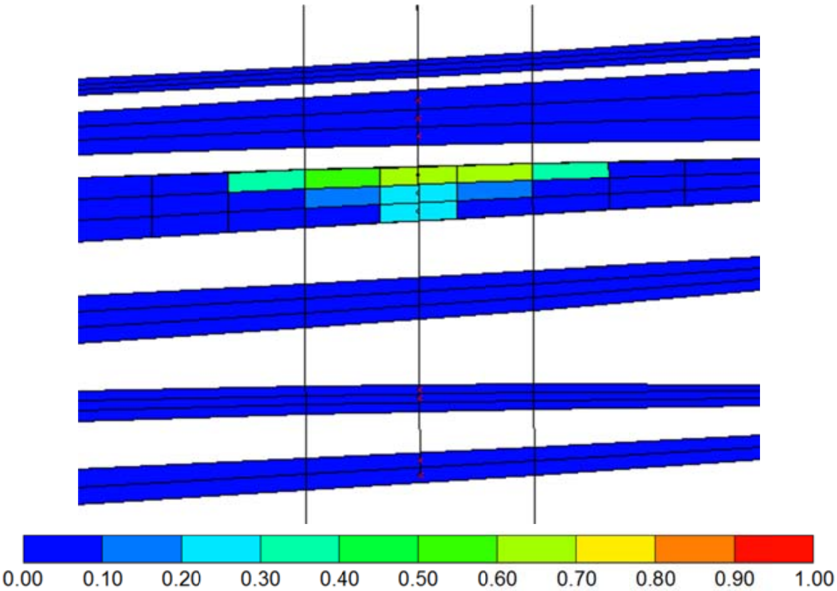


Fig. 11 Gravity overriding effect of injected CO_2.

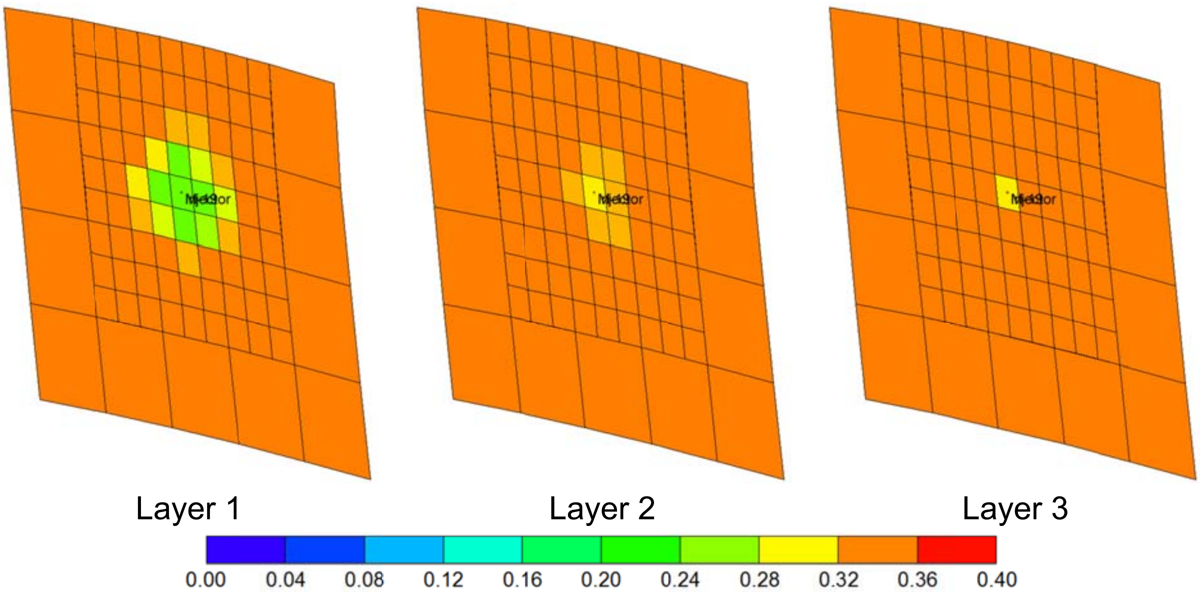


Fig. 12 Viscosity reduction of reservoir oil.

3.2 Huff and Puff Optimization

This simulation aims to find the optimal design of Huff and Puff process which can obtain maximum oil recovery. Cumulative oil recovery is considered as objective function. To optimize the Huff and Puff process, operation parameters including water injection rate, CO_2 injection rate, water injection time, CO_2 injection time, and soaking time are considered. Ranges of these parameters are summarized in Table 3. DECE (designed exploration and controlled evolution) method developed by CMG is used for optimization. The DECE method iterates designed exploration stage, which are applied to select the parameter values and create representative simulation datasets, and controlled evolution stage, which performs the statistical analyses for the results from designed exploration stage (CMG 2014). The result of optimization is described in Table 4. The result explains that higher water injection rate, longer water injection time, and soaking time can increase oil recovery. The optimum CO_2 injection rate and time of 30 tons/D and 33 days can also increase oil recovery.

Table 3. Design parameters for Huff and Puff optimization.

Parameters	Range of Value
Water Injection Rate	50~500 bbl/D
CO_2 Injection Rate	7~50 tons/D
Water Injection Time	10~120 days
CO_2 Injection Time	20~150 days
Soaking Time	10~120 days

Table 4. Optimum Design of Huff and Puff.

Parameters	Optimum Value
Water Injection Rate	495 bbl/D
CO_2 Injection Rate	30 tons/D
Water Injection Time	120 days
CO_2 Injection Time	33 days
Soaking Time	120 days

Oil rate and cumulative oil recovery are depicted in Fig. 13. In the optimum case, oil rate is dramatically increased after soaking time. Cumulative oil recovery of optimum case is improved by 12%. Fig. 14 is oil saturation at the end of simulation. In comparison with base case (Fig. 8), slight changes are observed at three layers. Cumulative WOR and GOR are described in Fig. 15. In comparison with base case, cumulative WOR of optimum case is increased by 10%. Cumulative GOR of optimum case is almost same with base case.

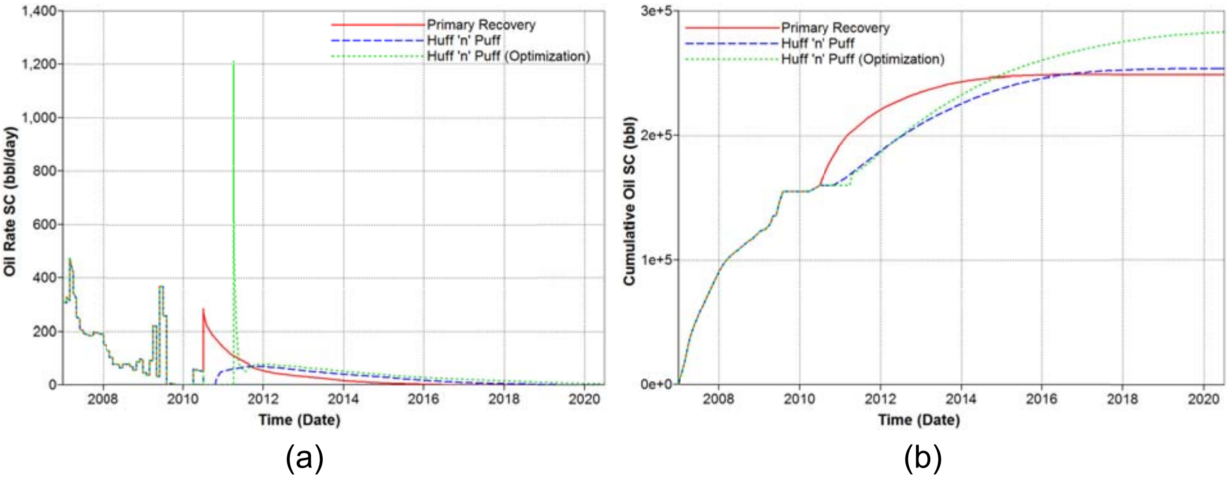


Fig. 13 Oil production of optimized Huff and Puff process: (a) oil rate, and (b) cumulative oil.

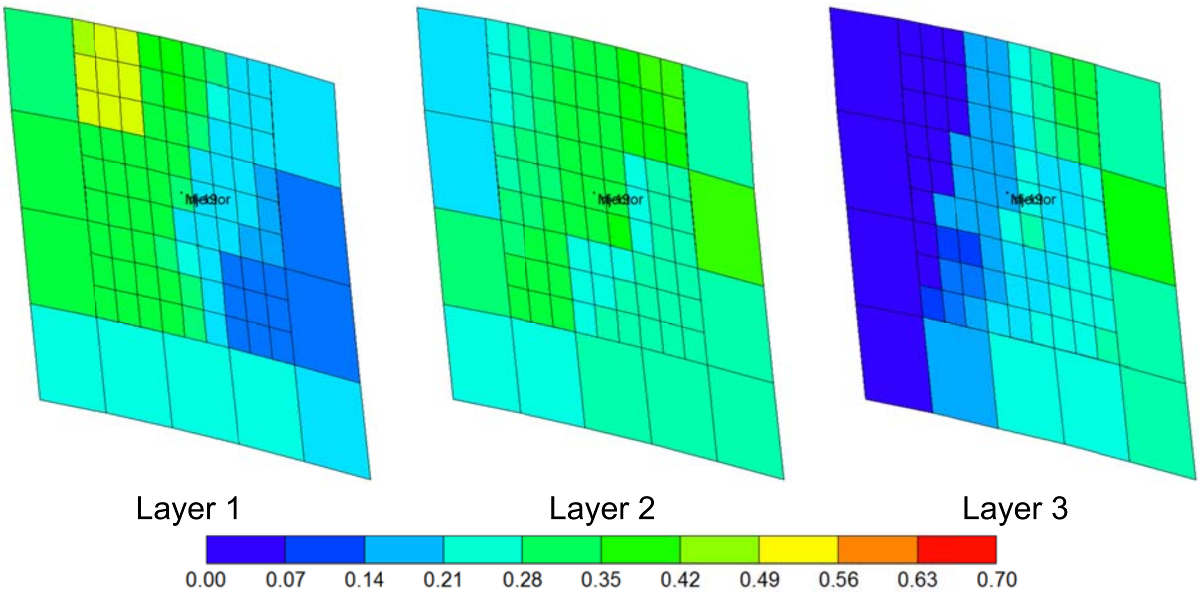


Fig. 14 Oil saturation of optimum case at the end of simulation.

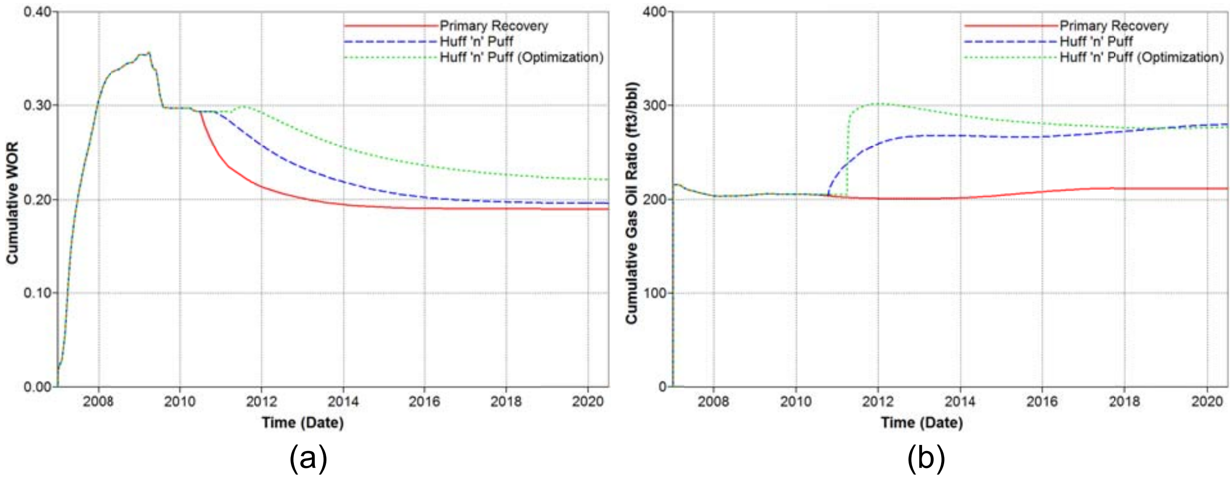


Fig. 15 Cumulative WOR and GOR of optimized Huff and Puff process: (a) cumulative WOR, and (b) cumulative GOR.

Fig. 16 indicates the CO_2 mole fraction at the soaking time. Gravity overriding effect also occurs in this case (Fig. 17). In this optimum case, swept zone with injected CO_2 is smaller than that of base case and CO_2 mole fraction at near wellbore is higher than that of base case. It is because average reservoir pressure is the highest in the optimum case due to the injected water (Fig. 18). In this condition, high pressure is needed to inject CO_2 and the injected CO_2 would be compressed. Oil viscosity is decreased considerably at near wellbore, caused by high CO_2 mole fraction. The viscosity is decreased by 70% in this case (Fig. 19).

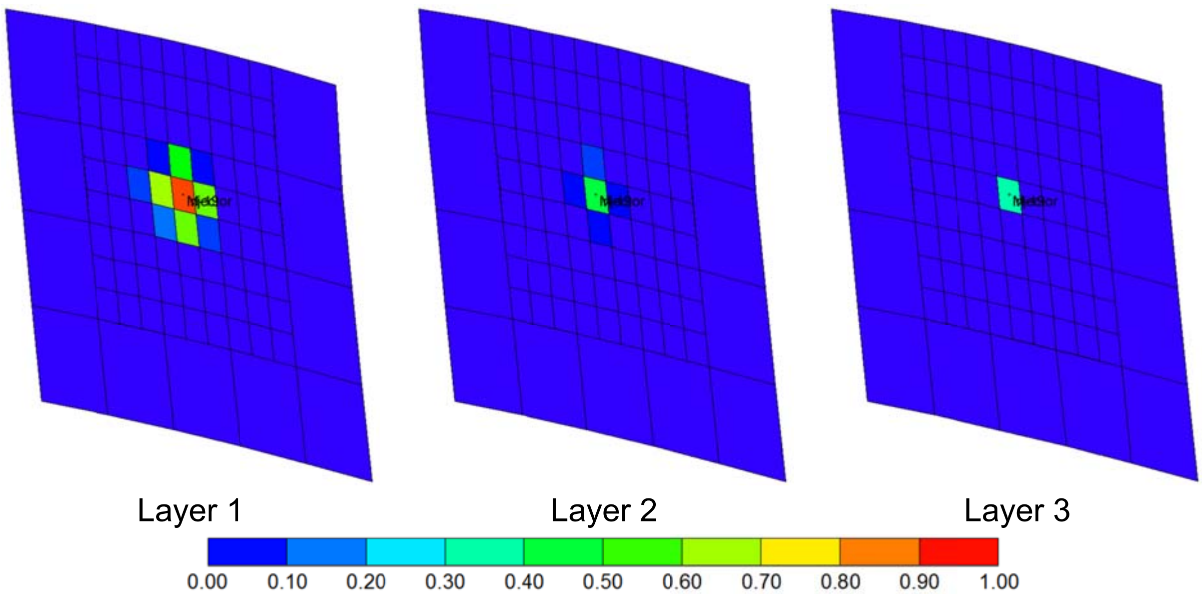


Fig. 16 CO_2 mole fraction of optimum case at soaking time.

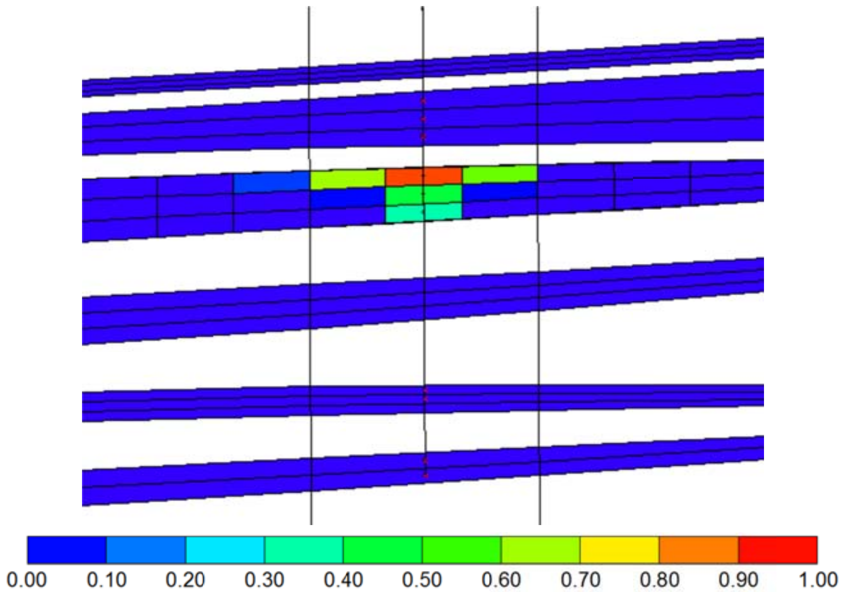


Fig. 17 Gravity overriding effect of injected CO_2 at optimum case.

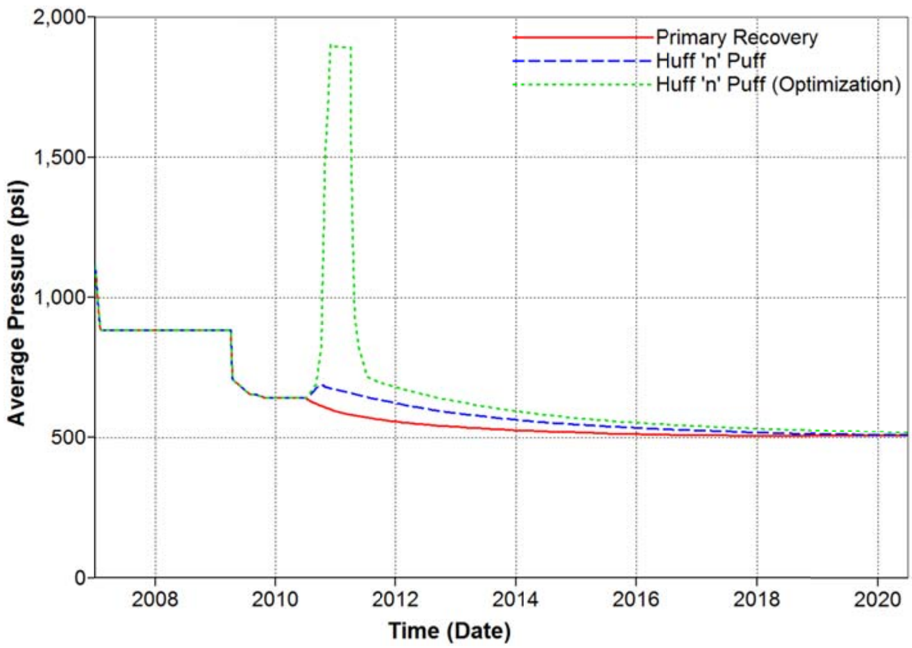


Fig. 18 Average reservoir pressure of three cases.

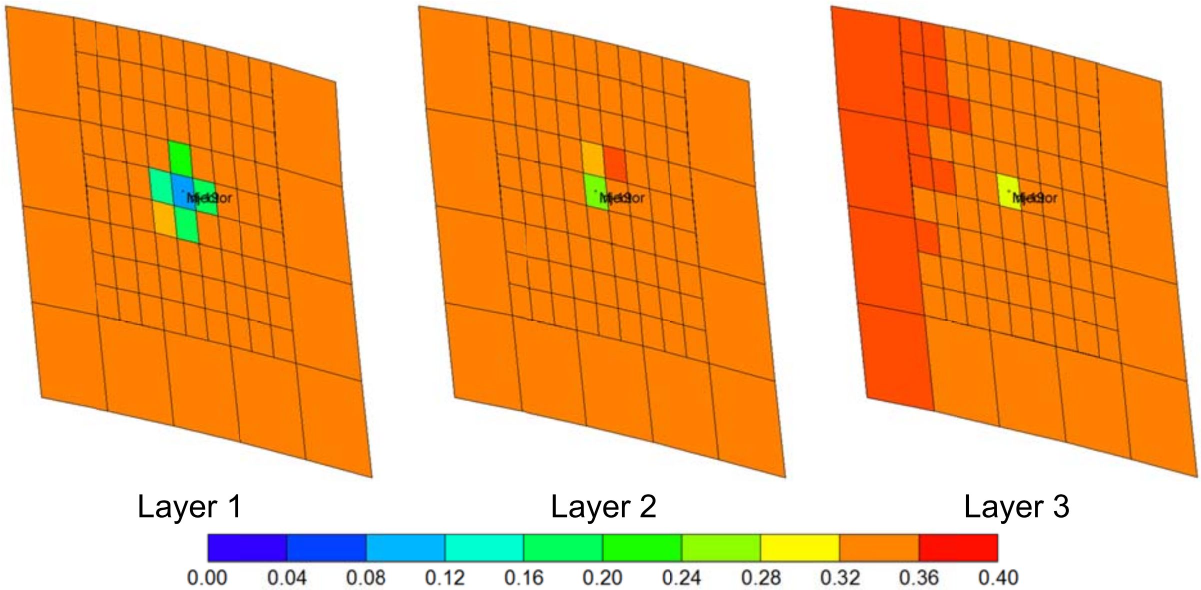


Fig. 19 Viscosity reduction of reservoir oil in optimum case.

4. CONCLUSIONS

(1) In this M field in Indonesia, CO_2 Huff and Puff showed 2% increment of oil recovery due to the oil viscosity reduction and swelling effect compared to the primary recovery case.
(2) Since the water injection rate is high in optimum case, reservoir pressure blocks CO_2 to be injected so that it needs high pressure and rate while injecting CO_2.
(3) In the optimum case, high reservoir pressure lead CO_2 to being more soluble into oil and oil viscosity was reduced significantly by 70%. Consequently, the oil recovery increased by 12%.
(4) CO_2 Huff and Puff shows sufficient potential to improve oil recovery and optimization is essential to maximize the efficiency of Huff and Puff process.

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