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An Investigation of Optimum Miscible Gas Flooding Scenario: A Case Study of an Iranian Carbonates Formation

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Abstract

Gas injection into carbonate formations is one of the most important activities to protect oil reserves that can guarantee a steady production .On-time injection of enough gas can result in the recovery of billions barrels of oil. In addition, it can preserve a huge amount of gas for the next generations. If the reservoir depth is shallow, or the reservoir fluid has a little amount of intermediate components, the flooding of rich gases is highly recommended. In the designing of a miscible injection process, firstly the minimum miscibility pressure should be measured or determined analytically. In this study, first the PVTi software is implemented to evaluate the miscibility of different injected gas, including carbon dioxide, nitrogen, methane, and different proportion of hydrocarbon gases. Subsequently, E-300 software is used to predict the recovery of the gas injection into the formation under study from one of the Iranian carbonate onshore fields. The investigation of the optimum injection rate as well as finding the proper layer of injection is investigated in details. The results show that the CO_2 flooding after a long natural production period result in higher efficiency than the miscible injection of methane at the early stage of production.

Keywords: Gas Injection Rate, Miscible, Immiscible, Recovery, Optimum Flooding Scenario

1. Introduction

Gas injection into oil reservoirs is one of the most important activities to protect reserves that can guarantee a steady production from a field. On time injection of enough gas can recover billions barrels of oil. In addition, it can preserve a big volume of gas for next generations.

Gas injection has been studied in detail in the petroleum literature. For example, Parvizi et al. (2014) studied an experimental investigation of the gravity drainage during immiscible gas flooding in a carbonate formation. In their study, nitrogen gas was injected into a single matrix block at different rates and directions. Their results showed that gas injection at gravity drainage rate gives the maximum recovery Moreover, the ultimate recovery decreases at much higher injection rates.

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There are very good reviews on CO_2 flooding during EOR, e.g. Manrique et al. studied the field experiences during EOR in a carbonate reservoir of the United States (Manrique et al., 2006). They indicated that CO_2 flooding (i.e. continuous or water alternate gas injection (WAG)) is a dominant EOR process in the United States. Hawez et al. showed that CO_2 injection below the minimum miscibility pressure (MMP) takes too long time to maintain reservoir pressure (Hawez et al., 2014). Moradi et al. experimentally studied a water-based nanofluid alternating gas injection as a novel EOR (Moradi et al., 2015). In their study, the smaller nano-size particles had a better recovery. Ghafoori et al. investigated N_2 and CO_2 WAG flooding in a carbonate formation (Ghafoori et al., 2012). The results showed that to optimize the recovery of CO_2 flooding, a continuous gas slug followed by a WAG flooding is required. There are also many studies dedicated to gas flooding with different compositions. Syzdykov studied gas injection performance in a low-permeability gas-condensate formation (Syzdykov, 2007). The results revealed that injecting a mixture of 50% C1and 50% N_2 into the upper part of the carbonate formation, starting as early as possible, results in the highest recovery. Ebrahimi et al. investigated hydrocarbon and non-hydrocarbon (i.e. CO_2 and N_2) flooding into one of the Iranian oilfields (Ebrahimi et al., 2012). A compositional reservoir simulator was implemented to evaluate the oil recovery of that field. Abedini et al. investigated the performance of immiscible and miscible CO_2 injection in a tight carbonate formation using both experimental and simulation approaches (Abedini et al., 2015). In that study, many attempts were made to history match the experimental results. Wang et al. studied the effects of impurities on CO_2 transport, injection, and storage. A simple formula has been developed to enable quick determination of CO_2 injectivity the effect (Wang et al., 2011).

Previous experiences showed that gas injection could be implemented in tight formations. For example, Zhao et al. introduced CO_2 flooding in horizontal wells of Ordos Basin tight oil reservoir. They showed that this EOR method could be helpful for the rapid and effective development of tight oil reservoirs in Ordos Basin (Zhao et al., 2016). Moreover, Abedini et al. studied the performance of immiscible and miscible CO_2 injection processes in a tight carbonate reservoir. All the test results were simulated using the CMG package, and attempt was made to history match the experimental results (Abedini et al., 2015).

During miscible gas injection, one of the most key factors which needs to be evaluated correctly is the evaluation of minimum miscibility pressure (MMP). In the literature, many comprehensive studies were conducted to evaluate MMP. For example, Shahrabadi et al. studied the effect of CO_2 concentration in injecting gas on MMP. Some displacement tests using slim tube apparatus were performed and recoveries and MMP's were measured. Finally, the experimental results were compared with the model predictions. Good agreement was achieved between the experimental data and model predictions (Shahrabadi et al., 2012). Moreover, Motaleby Nedjad et al. studied the determination of MMP by an analytical method. In their study, they proposed a method for solving a multi-component system based on the analytical calculation of ternary systems, which simplifies and converts the multi component system into a pseudo ternary system and estimates the minimum miscibility pressure without solving complex and time consuming equations of crossover tie lines (Motaleby Nedjad et al., 2007). Furthermore, Akbari et al. studied the determination of MMP in a gas injection process by using ANN with various mixing rules. Comparing the percentage error of this model to those of the previous literature data showed that the results obtained from the new MMP model were more accurate (Akbari et al., 2012). Finally, Jaubert et al. in their studies concluded that when the injected gas was not pure CO_2, it was enough to fit only two parameters of the equation of state on data, including classical PVT and swelling data, and then they used them to predict the MMP. The accuracy obtained was similar to the experimental uncertainty (Jaubert et al., 2014).

In this study, first the PVTi software is implemented to evaluate the miscibility of different types of injected gas, including carbon dioxide, nitrogen, methane, and some mixtures of hydrocarbon gases with different proportions. Subsequently, E-300 software package is used to predict the recovery of the injected gases into the formation under study from one of the Iranian onshore fields. Finding the best flooding scenario (i.e. the optimized scenario) with regard to efficient gas type, time of flooding, and injection location is the prime goals of this research.

2-Case study, reservoir data

The reservoir under study is located in the southwest of Iran and has a length of 34 kilometers, a width of 28 kilometers, and a height of 500 meters (Figure 1). The simulation model is composed of grids with the size of 2500×2500×300 ft. To do the simulations, a sector of this field model was considered that has 5×5×3 grids. The reservoir contains two wells, namely one production and one injection well. The former produces through all layers, i.e. full penetration, and the later injects gas into the bottom layer of the formation.

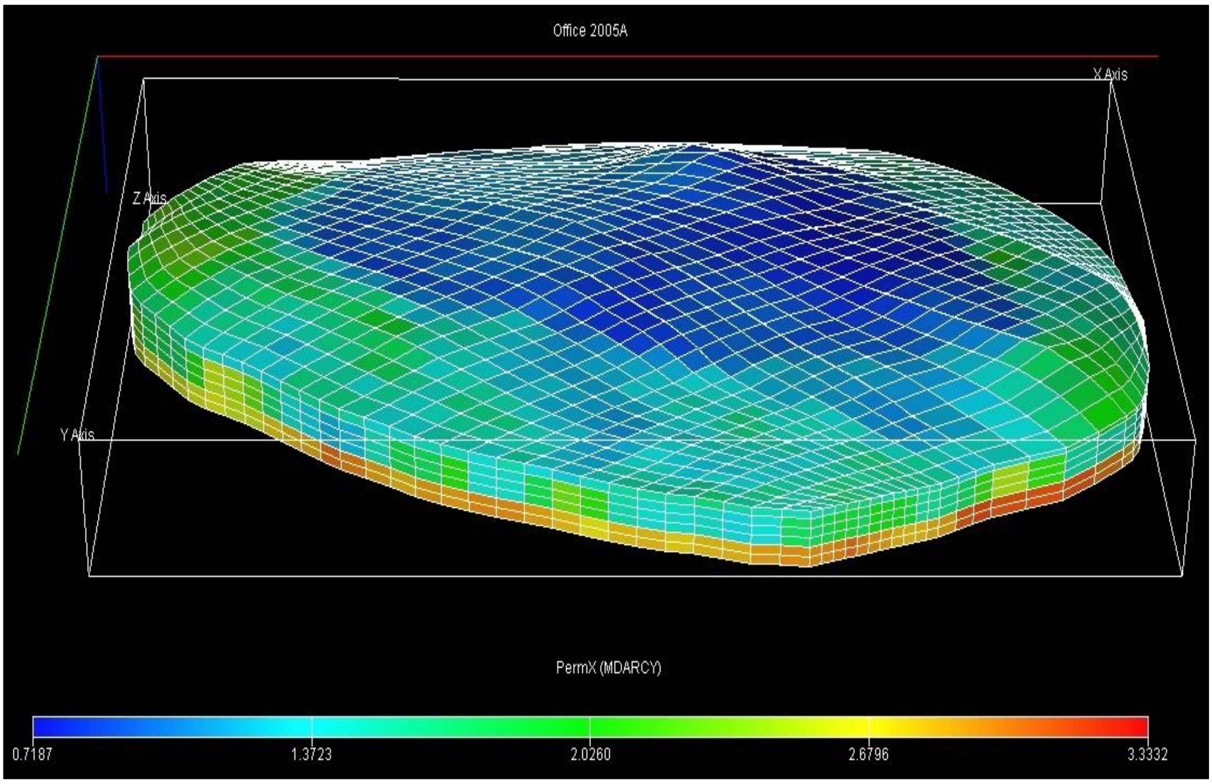

Figure 1
The geological model of the field under study: the distribution of reservoir permeability across the formation.

The reservoir fluid under study is a compositional type. The reservoir temperature is 150 °F, and its initial pressure was 4000 psia; the average permeability of the reservoir is 100 mD, and the porosity is 0.11. Figure 2 depicts the relative permeability and capillary pressure of the main rock type of the reservoir. As it can be seen, the cross section of both relative permeability curves is at a saturation value around 50%. Therefore, we can qualitatively say that this formation has a neutral wettability. Table 1 shows the components of the fluid sample and their properties. Prior to the compositional modelling in E300, we should tune the equation of the state (EOS). To model the fluid behavior, the EOS of Peng-Robinson was implemented in PVTi. This EOS is so popular in the petroleum industries and can predict the phase behavior of petroleum fluids very well (Ramdharee et al., 2013). There are so many studies in the petroleum literature that have successfully implemented this EOS in their analyses (Song Wei et al., 2000; Nasri et al., 2009).

Different analyses were considered during the tuning of EOS, including constant composition expansion, differential liberation, and bubble point pressure test in PVTi software. The phase diagram of the PVT sample after the tuning is depicted in Figure 3. To speed-up the simulations, some of the components were lumped together (Figure 4). To predict viscosity, the Lohrenz-Bray-Clark correlation was implemented.

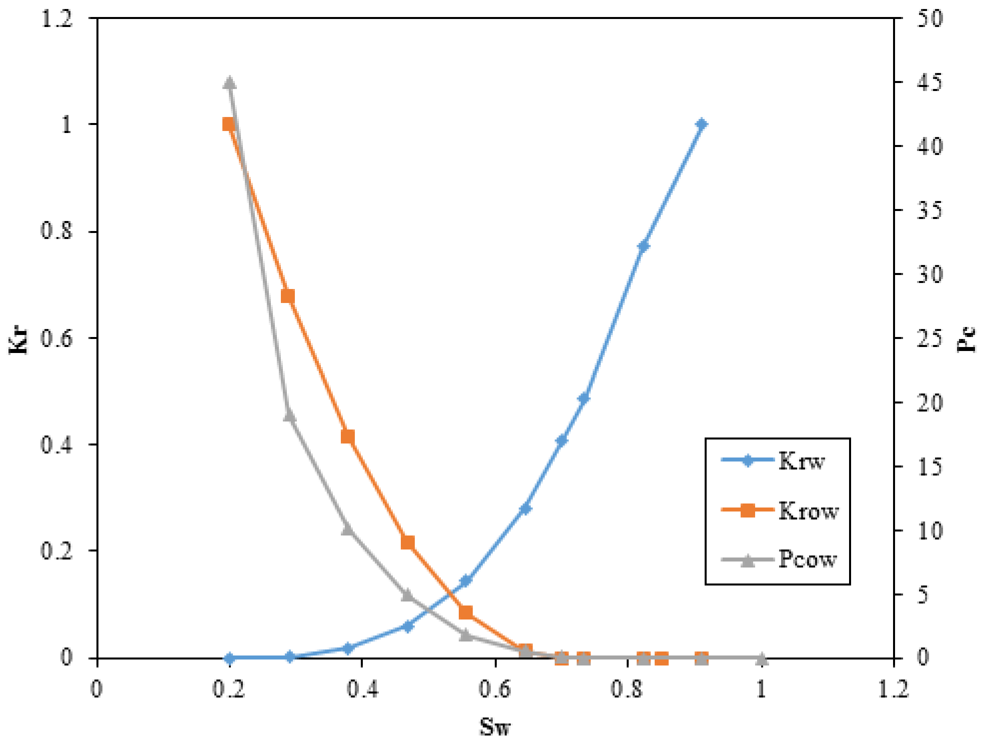

Figure 2
Relative permeability and capillary pressure data of the reservoir under study; the reservoir rock has a neutral wettability condition.

Table 1
Reservoir fluid components and their parameters.

Components	Molar Fraction (Fraction)	MW (g/mol)	*Pc* (bar)	*Tc* (K)	*Pc* (m^3/kg.mol)
C1	0.4	16.563	76.65	203.786	0.098
C2	0.1	30.07	48.839	305.430	0.148
C3-C6	0.1	49.369	71.279	339.297	0.221
C7-C10	0.2	120.118	74.482	1408.507	0.482
C11-C17	0.15	185.069	73.427	1638.818	0.712
C18+	0.05	303.675	67.394	1902.062	1.065

As an example, Figures 5 and 6 show the tuning results subsequent to the tuning process for constant composition expansion (CCE) and differential liberation (DL) tests. As indicated, there is a good match between the experimental results and the EOS predictions, which was obtained by changing the weight factors of the tests as well as the properties of the plus fractions and binary interaction coefficients.

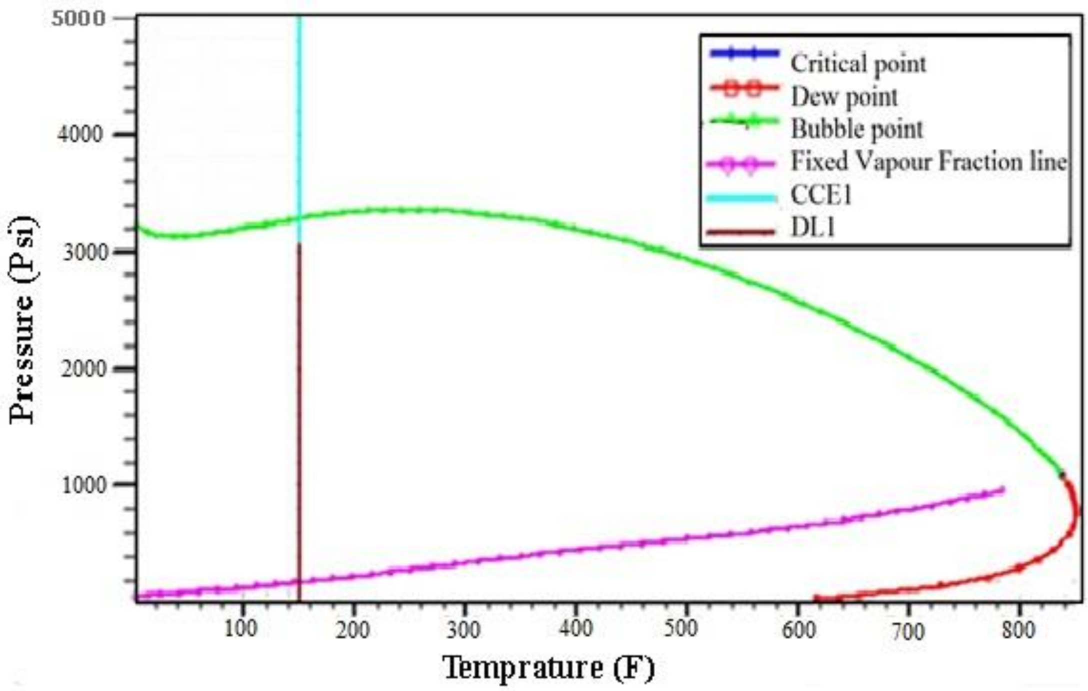

Figure 3
Phase behavior of the reservoir fluid.

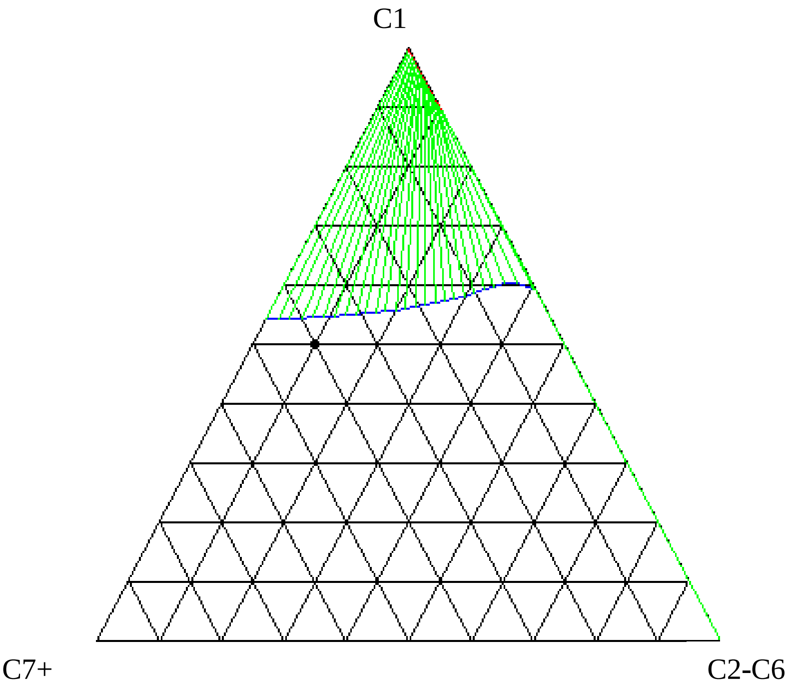

Figure 4
Ternary plot of the reservoir component based on grouping of C1, C2-C6, and C7+.

3. Results and discussion

3.1. MMP determination

The first stage of our study was the determination of MMP at first contact (FCM) and multiple contacts (MCM) for different injected gases. At a constant temperature and composition, the lowest pressure at which miscibility (dynamic miscibility) can be achieved via first or multiple contacts is called MMP. At MMP, the interfacial tension is zero, and no interface exists between the fluids.

Table 2 shows the result of the MMP determination. As it can be indicated, different gases with a wide range of compositions from pure methane and CO_2 to a variation of lighter components were considered during the MMP estimation. Our results showed that the injected mixture gas containing 90% C1 and 10% C2 has the higher MMP, while the injected gas composed of 100% CO_2 has the lowest MMP value.

Methane and ethane are hydrocarbon gases and can be miscible in reservoir components at a suitable pressure and temperature. In contrary, N_2 and CO_2 are immiscible at low pressures since these gases are non-hydrocarbon. At a low pressure, they can push the reservoir fluids and help production. According to Table 2, for a miscible injection at the initial pressure of reservoir (4000 psia), a mixture of50% C1 and 50% C2 is the best scenario since the MMP of this gas is very close to the formation pressure.

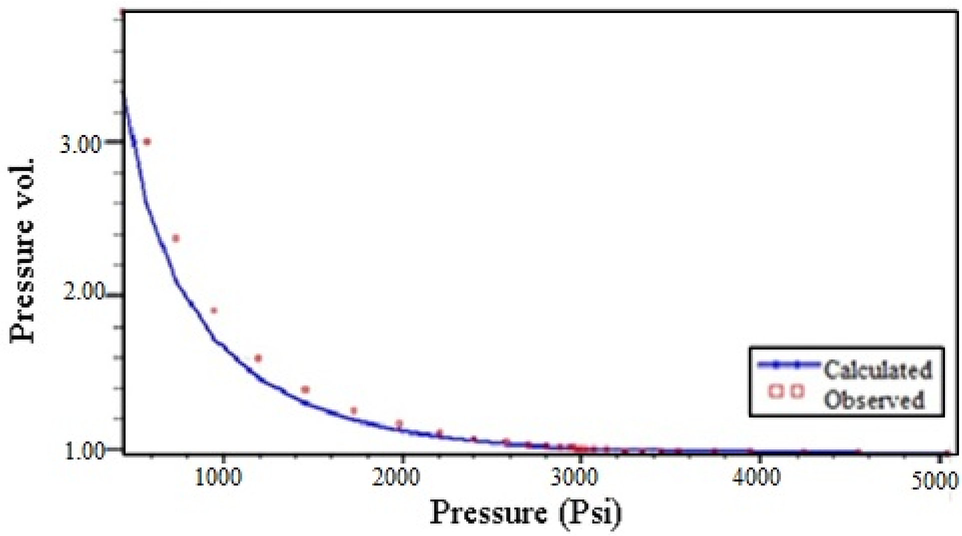

Figure 5
Relative volume of oil to gas at different pressures.

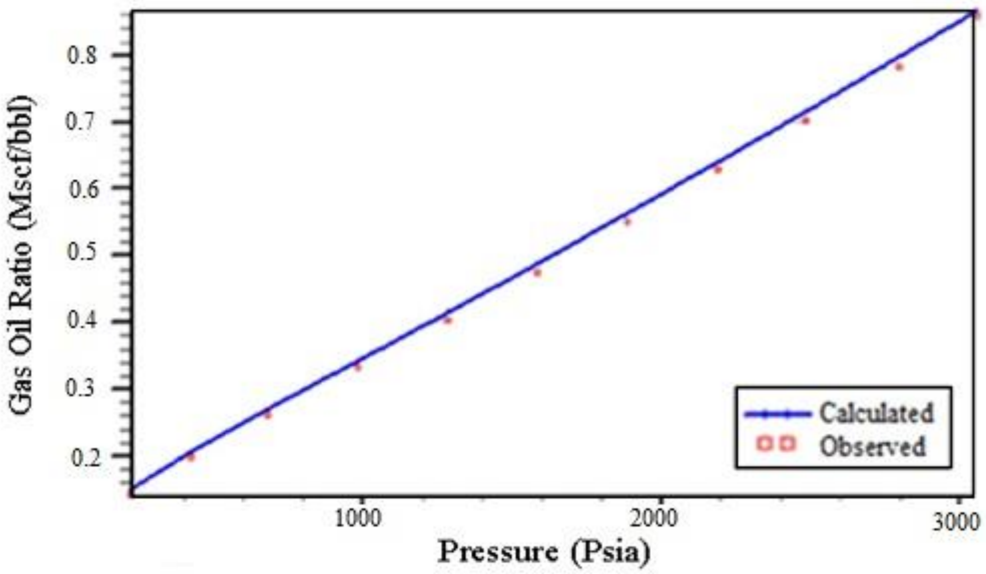

Figure 6
Gas to oil ratio versus formation pressure.

Table 2
The results of FCM and MCM with different gas injection components.

Gas Type	**100%C1**	**33%C1/67%C2**	**35% C1/ 65%C2**	**40%C1/60%C2**	**45%C1/55%C2**	**50%C1/50%C2**	**55%C1/45%C2**	**60%C1/40%C2**	**70%C1/30%C2**	**80%C1/ 20%C2**
FCM (psi)	6157	3056	3222	3557	4512	4893	5177	6048	9295	13933
MCM (psi)	6006	3056	3056	3056	3263	3806	4180	5445	9143	9359
Gas Type	**90%C1/10%C2**	**30%N_2/70%C2**	**40%N_2/60%C2**	**45%N_2/55%C2**	**50%N_2/50%C2**	**20%N_2/30%C1/50%C2**	**30%N_2/20%C1/50%C2**	**30%N_2/30%C1/40%C2**	**40%N_2/20%C1/40%C2**	**100% CO_2**
FCM (psi)	14677	3692	4769	5424	4940	6526	6526	6526	6931	3056
MCM (psi)	12646	3056	3799	4381	4220	3056	3056	3056	3056	3056

3.2. Investigation of different gas flooding scenarios

At the early stage of the reservoir life, the production was achieved through natural production, while at later times, gas flooding started. Reservoir simulation can determine the performance of the reservoir during the production period by finding the formation key parameters, e.g. reservoir efficiency, field production rate, field pressure etc. Figure 7 shows the result of all gas flooding scenarios mentioned in Table 2. Subsequent to about 4000-day production with natural mechanism, miscible gas flooding was started to improve the recovery. If we continue with natural production, the ultimate recovery of about 27% can be achieved through the reservoir life. Among the injected gases, the simulation results revealed that the CO_2-flooding efficiency (82%) was the best among all the other scenarios for a long production period. Nevertheless, in the early and medium stages of flooding (until 25 years after the first production), the gas-flooding scenario with a mixture of 50% ethane and 50% methane with a recovery factor of 0.77 could be the best plan. Moreover, at early and medium stages, the N_2 flooding had the best pressure maintenance in this reservoir, but the efficiency of this flooding was not so different from the other gas flooding scenarios later. Furthermore, the hybrid flooding of gases at different time intervals might have better results, which needs further investigations.

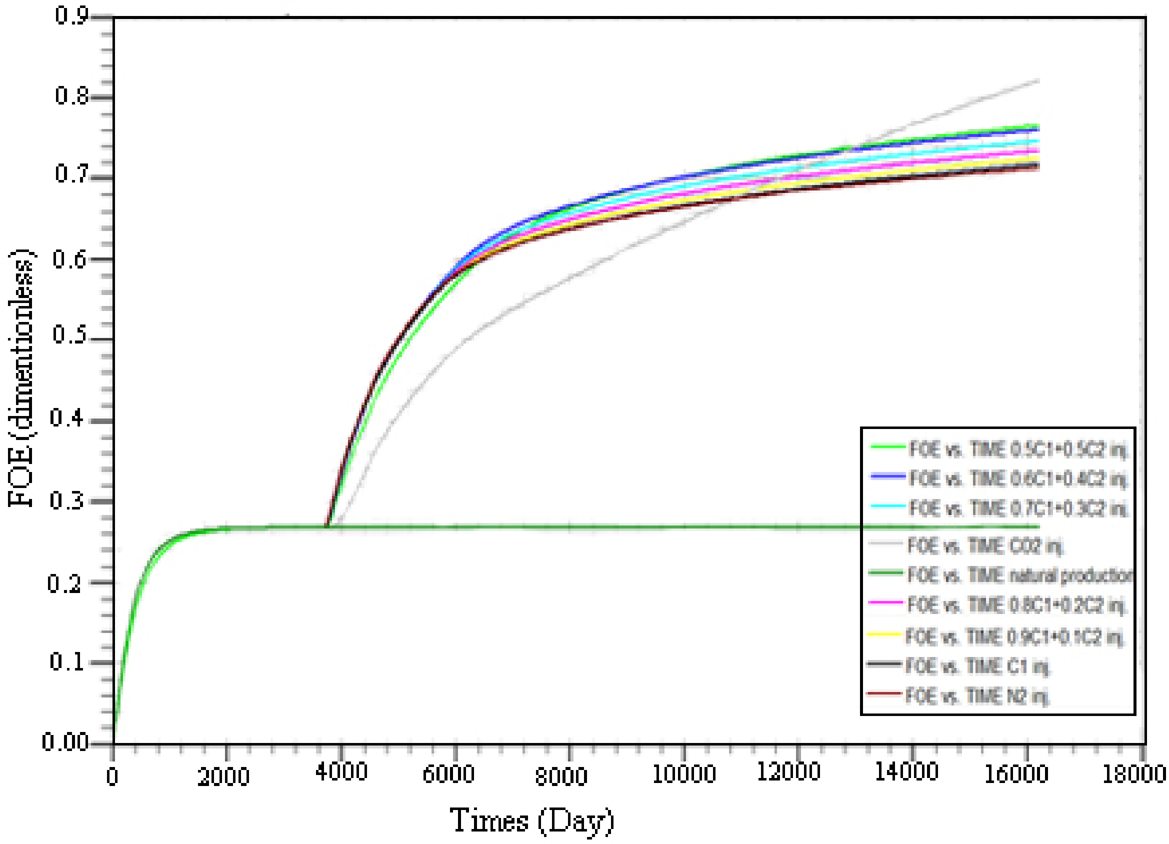

Figure 7
Field efficiency during different gas flooding scenarios; the injection scenarios were started after 4000 day natural production from the field.

According to the PVT results, in the flooding case of a mixture of 50% C1 and 50% C2, the injected fluid could be miscible at a pressure less than the bubble point of our sample. Therefore, implementing fluid compositions that have a higher C2/C1 ratio was not suitable because gases containing heavier components are not so economic. According to the results, at higher reservoir pressures, lower C2 fractions in the injected gas can be implemented. In this situation, gas flooding can be miscible (or semi-miscible) and can have the best performance.

Table 3
The ultimate recovery factor from different gas flooding scenarios.

Gas injection type	Recovery (fraction)
Natural production	0.27
100% C1	0.72
90% C1 and 10% C2	0.72
80% C1 and 20% C2	0.74
70% C1 and 30% C2	0.75
60% C1 and 40% C2	0.76
50% C1 and 50% C2	0.77
N_2	0.71
CO_2	0.82

Nitrogen as well as the other non-hydrocarbon gases behaves the same as methane.

Figure 7 depicts the field pressure for different gas flooding scenarios. In the injection well of all the scenarios, the gases are injected at a constant pressure of 4000 psi, and about 15000 MSCF of gas was injected. Figure 8 shows that during the early and medium stages of the flooding process, the N_2 flooding has the best reservoir pressure maintenance. However, at the later time, the efficiency of this flooding is not so different from flooding by the other gases.

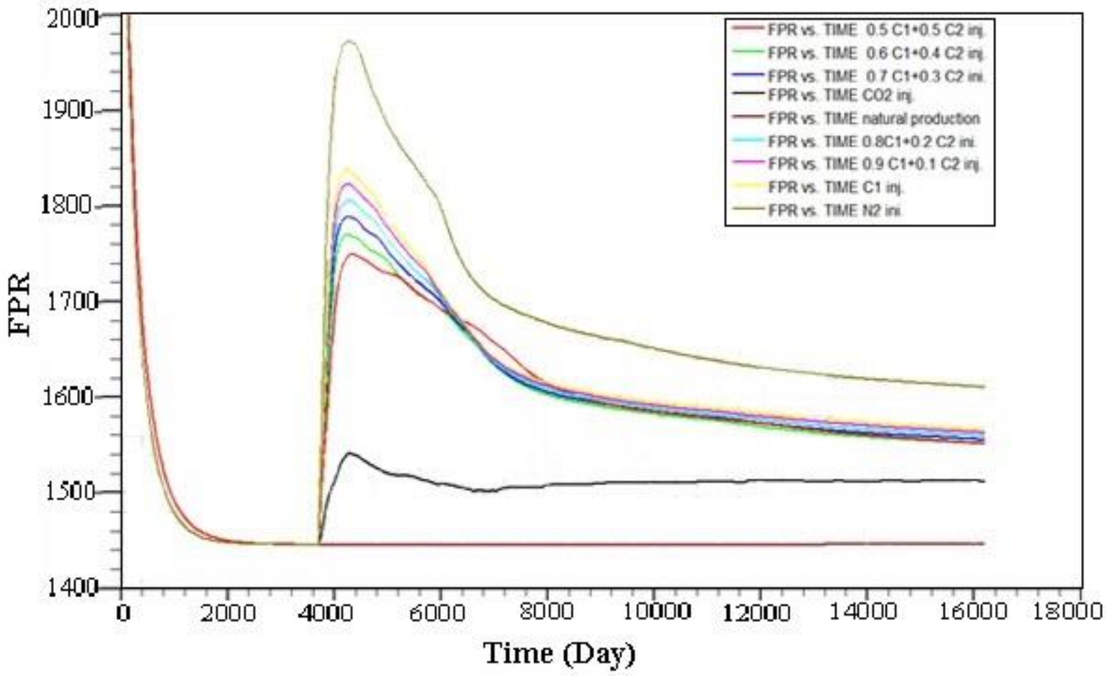

Figure 8
Field pressure during different gas flooding scenarios; the start point of gas injections is around 4000 days.

Figure 9 compares the different flooding scenarios together. In two scenarios, the CO_2 injection and C1 injections were started subsequent to 10-year natural production, while there is another scenario, in which the CO_2 flooding was started with a 12-year lag following to the natural production (the injection starts after 22 years of natural production). According to this figure, the CO_2 flooding following to a 22-years natural production can have the same efficiency as the case with 10-years of methane flooding. This is interesting as the final recovery of these two scenarios is in the same order, while the consumption of the injected gases is so different from each other. Thus, instead of methane flooding during early stages, we can continue with natural production until the middle flooding stages (in this case, equal to double of the natural production time), and then we can inject CO_2. These two scenarios will have the same efficiency in long time intervals.

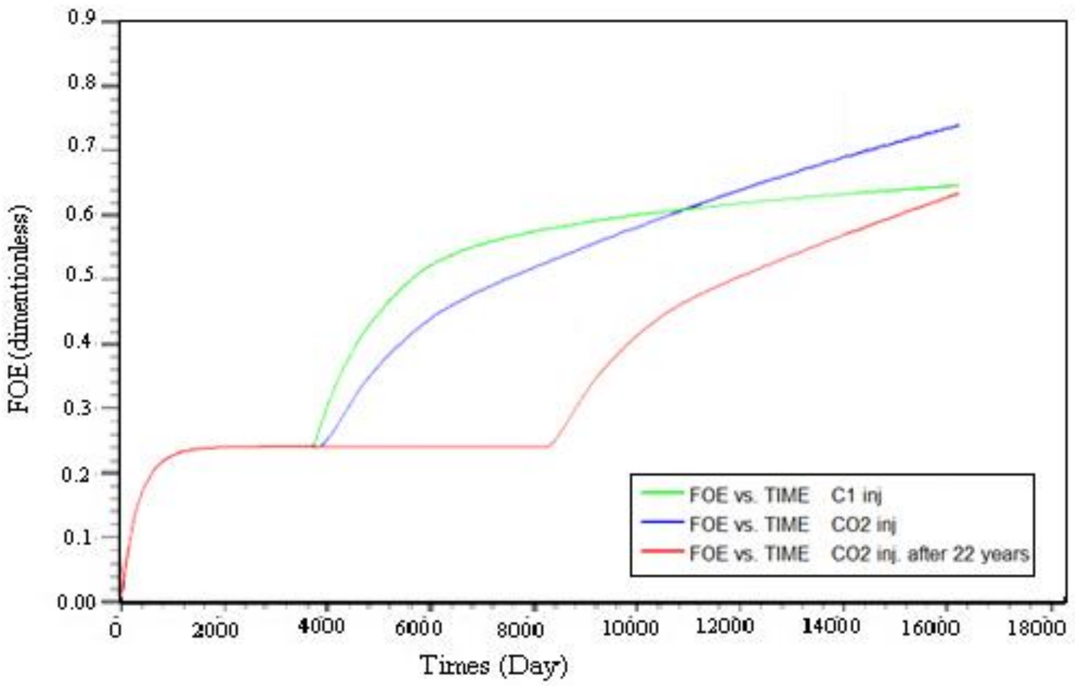

Figure 9
Field efficiency (recovery factor fraction) for CO_2 and C1 flooding at different stages of the reservoir life.

The most attractive scenario is the CO_2 flooding as this gas is miscible with the formation fluid. Lower gas-oil ratio during CO_2 flooding is an indicator that this gas is more miscible than the other fluids considered herein; this behavior is shown in Figure 10.

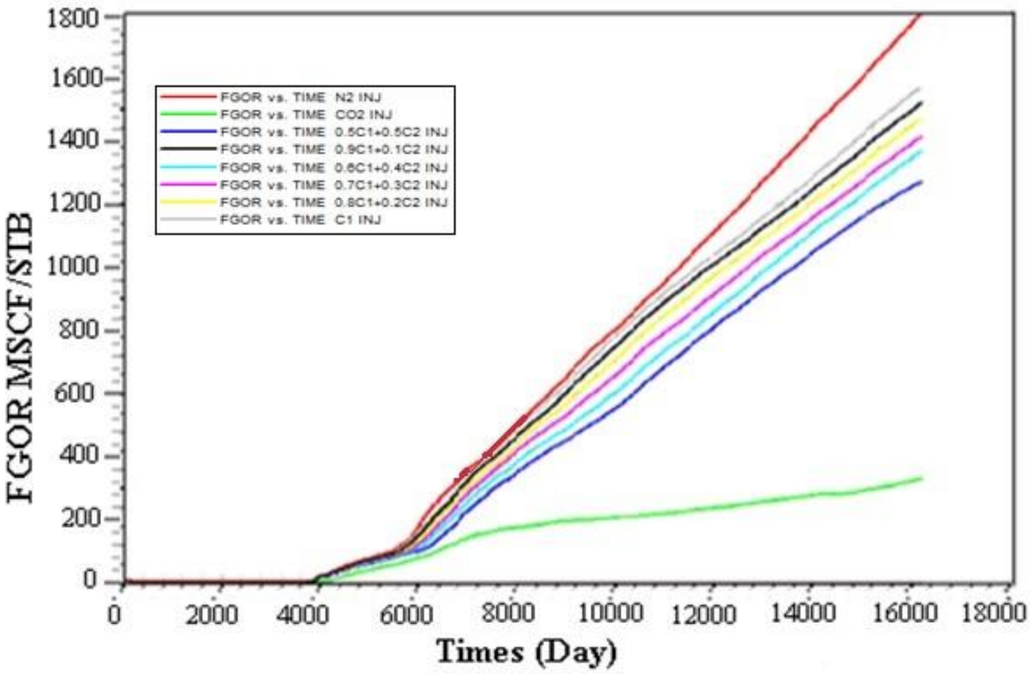

Figure10

Field gas to oil ratio for different gas flooding scenarios; miscible flooding scenarios show less GOR or less gas breakthrough.

In the aspect of water-cut of the production well, the CO_2 flooding showed better efficiency by less water producing (Figure 11), while the N_2 flooding had the worst efficiency among all scenarios. It is worth mentioning that the reservoir model does not contain any aquifer or water injection well.

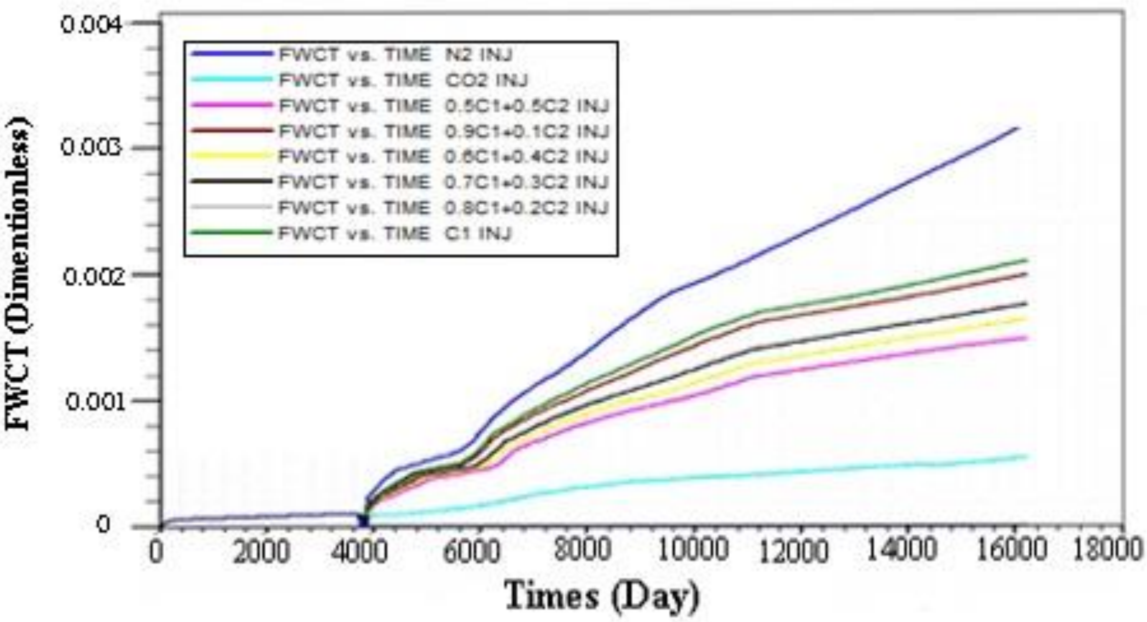

Figure 11

Field total water cut during different flooding scenarios.

3.3. Finding optimum gas injection rate

In this sensitivity analysis, gas is injected at different rates to improve the reservoir efficiency. Gas can be injected in different layers. In fact, gas should be injected into the lower active layers, where its permeability is higher, and the gas can be in contact with the oil phase for a longer time. If the gas flooding process is miscible, there is no different between the top or bottom layer of the reservoir in the case of equal layer permeability. By raising the injection rate from 1000 to 5000 bbl/D, reservoir efficiency was improved (Figure 12 and Table 4).

3.4. Investigation of gas flooding in different layers

Gas injection can be affected by the location of the injection into reservoir layers, porosity, permeability, availability of faults etc. Injecting the gas into the bottom layer of the reservoir can push the reservoir oil up to the production well. Injecting the gas into the middle layer distributes the gas to the upper layers, so it can be suitable for a miscible process. Finally, injecting the gas into the upper layers has a risk of increasing the gas-oil ratio in the production well. Figure 13 illustrates gas flooding in different layers of the formation under study.

While the gas-flooding process is miscible, there is no difference between injections into the top or bottom layers. Therefore, gas injection into the high-permeability layers of a reservoir or deeper layers is recommended. While the injected gas moves toward the production wells, it can be in contact with more oil phase. Thus, the miscibility processes can be speeded up.

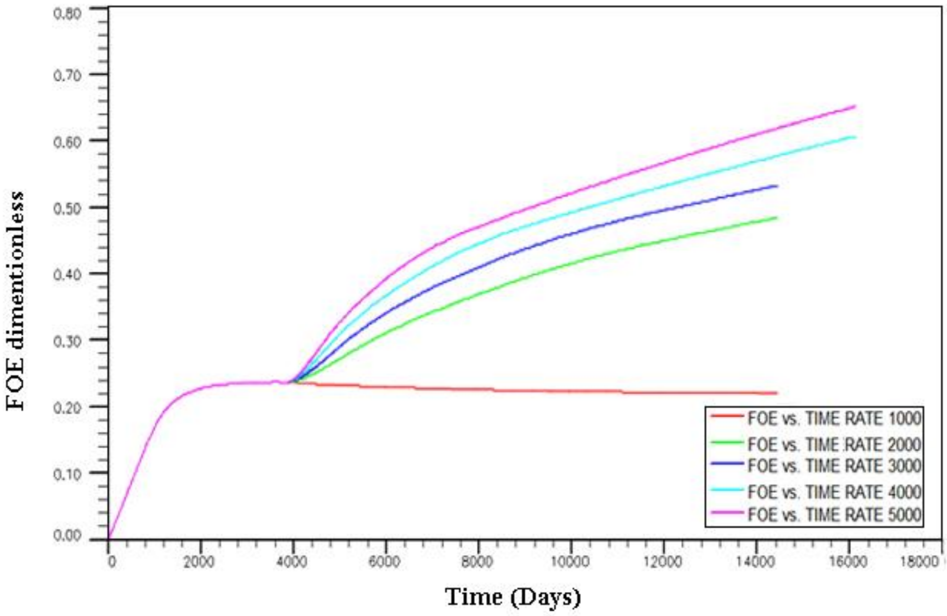

Figure 12
Field efficiency after CO_2 flooding at different rates.

Table 4
Field efficiency at different CO_2 flooding rates after 14000 days.

Flooding Rate (bbl)	Recovery factor (fraction)
1000	0.25
2000	0.54
3000	0.59

4000	0.64
5000	0.68

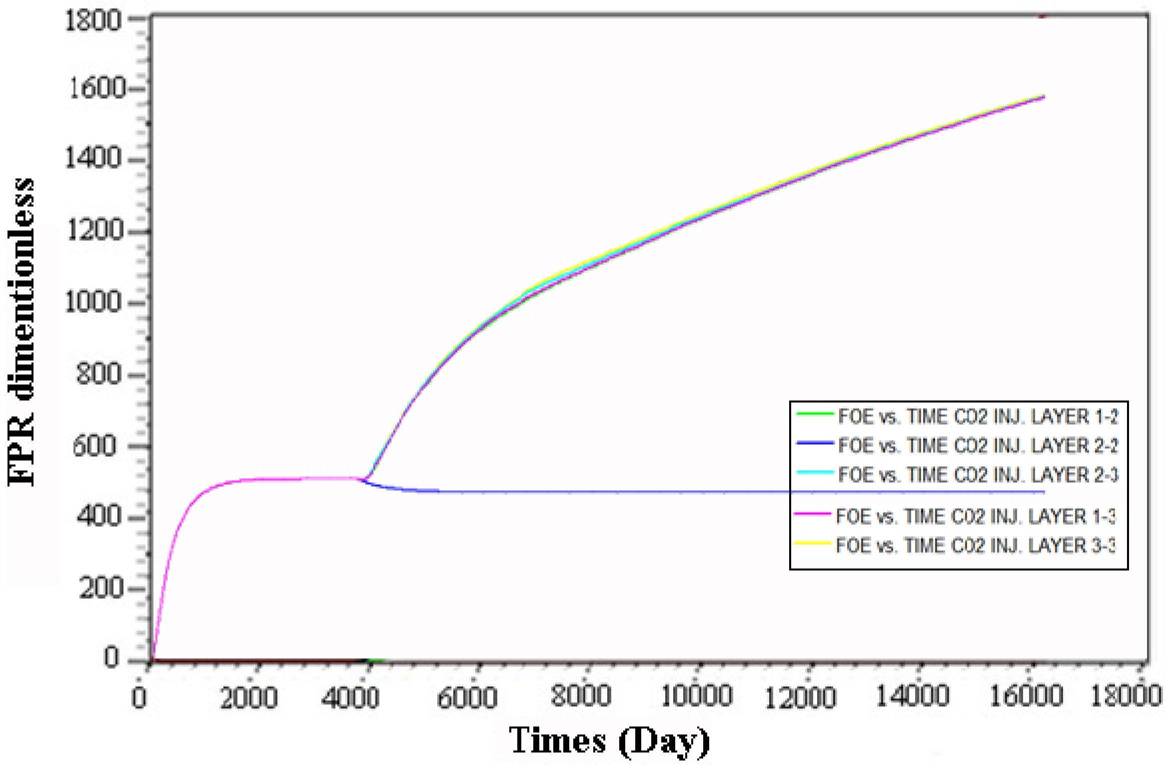

Figure 13
Field efficiency after CO_2 flooding into different layers of formation under study.

4. Conclusions

In this study, the best gas-flooding scenario with the highest efficiency was considered in details. The MMP estimation of various gasses with different components was analyzed as well. The results revealed that during the short and middle stage of the reservoir life, a miscible gas composed of 50% C1 and 50% C_2 had the highest recovery; however, the final recovery value is not so different from pure methane flooding. In addition, the efficiency of injecting 100% C1 through all reservoir life is equivalent to the miscible CO_2 flooding from the middle stage of the reservoir life. The CO_2 flooding was better than other gas injection scenarios in a long injection period. Furthermore, it has been investigated that injecting gas at different rates could improve the reservoir efficiency; methane is a cheap and accessible gas compared to the others, so, at early stages, it should be better for injection in the reservoir, while at later stages CO_2 has the best efficiency; however, CO_2 is not suitable for Iranian reservoirs, so we should inject methane. Nonetheless, high injection rates should be avoided. The results showed that the layer where the gas is being injected is also of the prime importance. It is better to inject the gas into the active layers of the reservoir with higher permeability and higher depths. According to the results, we can also select the best scenario at early stages and in a long period of time after gas injection.

Nomenclature

C_1	: Methane gas

C_2	: Ethane gas
CO_2	: Carbon dioxide
E300	: Eclipse 300 software
EOS	: Equation of state
FCM	: First contact miscibility
FGOR	: Field gas oil ratio
FOE	: Field oil efficiency
FPR	: Field pressure reservoir
FWCT	: Field water cut
MCM	: Multiple contact miscibility
MMP	: Minimum miscible pressure
N_2	: Nitrogen gas
PVTi	: PVTi software

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