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STUDDING DIFFERENT MISCIBLE GAS INJECTION INTO SOUTHWESTERN IRAN'S OIL RESERVOIRS USING ECLIPSE 300

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ABSTRACT

Background: Fractured reservoirs are always considered poor candidates for enhanced oil recovery. This is due to the complexity in predicting the efficiency of fractured reservoirs. The gas injection method may significantly increase the oil recovery factor. One of the important mechanisms for enhancing the extraction from fractured reservoirs is miscible gas injection. The aim of this paper is to study miscible gas injection into oil reservoirs with Eclipse 300 application. **Methods:** In this study, miscible injection of gasses including methane (CH₄), Carbon dioxide (CO₂) and Solvent are discussed under different scenarios such as different injection rates, different injection charges, different combinations for the solvent gas, as well as the completion method of the injection well with Eclipse-300. **Results:** An analysis of the Minimum Miscibility Pressure (MMP) using software PVTi revealed that the Solvent gas having the lowest miscibility pressure (4808 PSIA) and CO₂ having the highest miscibility pressure (14670 PSIA) occurred in the first contact. **Conclusion:** Therefore, the solvent is the most appropriate gas for miscible injection into oil reservoirs due to its low miscibility pressure, higher oil production and lower gas production.

INTRODUCTION

Iran is an oil-rich country whose economy is largely oil-dependent. As such, EOR methods are necessary to ensure increased efficiency in the extraction of oil [7]. Notably, the Iranian oil reservoirs are quickly being depleted, which calls for the use of EOR projects in the exploitation of the oil. Besides, the use of other traditional and inefficient oil extraction methods has made nearly 10 billion barrels of crude oil non-recoverable [1] [7].

In the light of these inefficiencies, miscible gas injection is the recommended method for EOR from reservoirs in Iran. It will significantly increase the extraction rate; thus ensuring the effective parameters for optimum injection mode, which includes injection pressure, injection flow, duration of injection, composition of the injected gas are necessary for the intended process. The method, therefore, shows that engineering science-based sustainable exploitation prevents waste of national assets [4].

In initial stages, the production from an oil reservoir is normally done based on the natural energy of the reservoir itself. This means that from the beginning, the energy required to guide the fluid into the wells is supplied by mechanisms governing the reservoir [3]. These include:

1. Water propulsion
2. Gas-cap expansion
3. Gas solution propulsion
4. Gravity drainage
5. Combined mechanism

Furthermore, oil production range, except in certain cases, is not very appropriate for each of these mechanisms. Therefore, oil producers sought to use EOR methods to extract higher oil volumes based on economic aspects.

Accordingly, method of developing an oil field was divided into four stages as follows:

1. Initial recovery or the natural production from the reservoir
2. secondary recovery
3. tertiary harvest
4. ultimate recovery

Miscible gas injection is one of the main EOR methods. It is increasingly being used globally to produce more oil. According to published reports, the injection of CO₂ in the continental of America and miscible injection in Alaska has increased oil recovery significantly [4]. Today it is well known that miscible gas injection greatly increases oil production and is effective in recovery of oil that is hardly produced naturally.

KEY WORDS

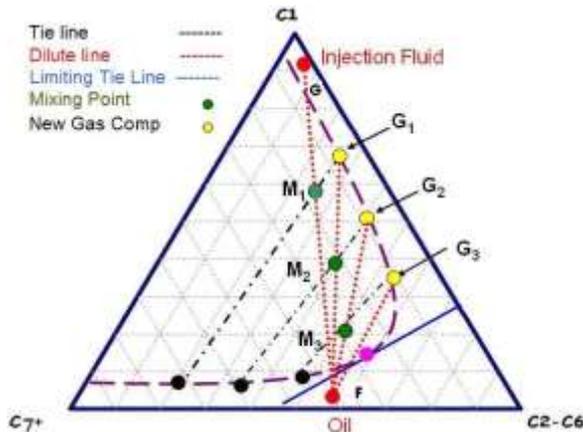
Simulation, miscible gas injection, oil reservoirs

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Theoretical principles

The mechanism of mixing two fluids includes multiple stages of displacement and mixing. The cost of miscible displacement is reduced through injection of a rich gas or diluting the injected LPG by natural gas. The fund aspect of this process is to determine the maximum amount of dilution while maintaining the miscible mode. To understand the displacement and mixing stages, the composition of oil and gas is taken into consideration as in the form of compounds with three virtual components. However, in general, this method does not have a high degree of accuracy [2]. The uncertainty on accuracy stems from the assumption that oil and gas could be separately converted to virtual components through an appropriate method so that the general properties of oil and gas can be predicted using corresponding virtual components well but it is hardly concluded that virtual components of the oil are quantitatively the same as those of the gas. Notably, the more the difference between the properties of three virtual components of the oil and those of three virtual components of the gas, the lower the accuracy of results to determine the miscibility conditions will be. In addition, during the mixing process the quality of components between the reservoir fluid and the injected fluid changes [2]. As such, to determine the miscible conditions using triangular diagrams, it is assumed that virtual components of oil and gas are completely identical and no quality change occurs during the process of mixing. The assumption is the major weakness of studies



conducted based on triangular diagrams. However, it should be acknowledged that triangle diagrams are very useful for understanding the theme and overall conclusions clearly. In [Fig. 1], the fuzzy triangular diagram is shown as an example [2].

Fig. 1: Fuzzy triangular diagram.

The flooding process may occur in three ways:

1. Miscibility in the first contact (First contact) by injecting liquids gasses such as NGL
2. Condensate miscibility or miscibility by rich gas injection.
3. Evaporative miscibility or dry gas injection at a high pressure

Each point within the triangular diagram represents a specific combination of virtual components C1 (methane), C2-C6 (intermediate components that often include ethane, propane, hexane. . .) and C7 + (heptane and heavier hydrocarbons). Through experiments the ACB curve could be plotted in the specified pressure and temperature [See Fig. 1], so that concentrations in which the fluid is broken into two phases at the equilibrium state, as well as single-phase fluid concentrations are determined [3]q. The ACB curve is, in fact, the boundary separating the single-phase and two-phase modes. The BC curve indicates the concentrations of saturated gas (Dew Point Curve) and the AC curve indicates concentrations of saturated liquid (Bubble Point Curve). The saturated liquid concentration is connected to the saturated gas concentration by Tie Line in the equilibrium state [3].

Reservoir fluid composition, injection fluid composition, temperature and pressure are determining parameters in the miscible injection process. In oil reservoirs, temperature could be assumed to be constant. The relationship between concentration and pressure is shown in the triangular diagram in [Fig. 2](Whitson, 2001).

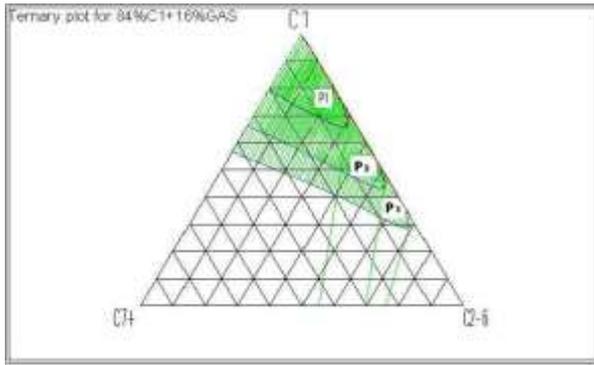


Fig. 2: Effect of pressure at the triangular diagram ($P_1 > P_2 > P_3$).

The tie line that is tangent to the critical point is called the critical tie line. When the concentration of the fluid reservoir and injected fluid is converted to three virtual components, the points representing the fluids could be easily determined on the triangular diagram. In the following figures, point G represents the gas and point F represents the fluid. When these points occur on both sides of the critical tie line, miscible displacement of reservoir fluid occurs through gas injection into the reservoir after repeated contacts between two fluids. Evaporative miscibility that represents miscible displacement with dry gas injection at a high pressure is shown in [Fig. 3]. Condensate miscibility that represents miscible displacement with rich gas injection is shown in [Fig. 4].

Fig. 3: Miscible displacement with dry gas injection at a high pressure (evaporative miscibility).

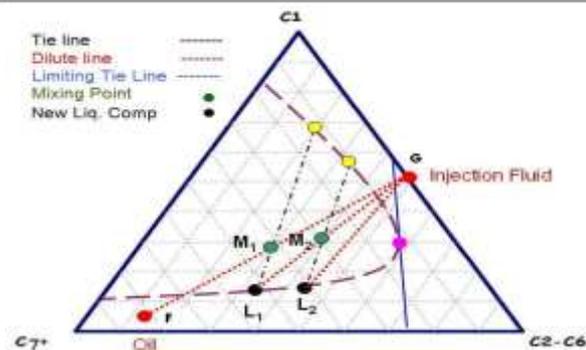
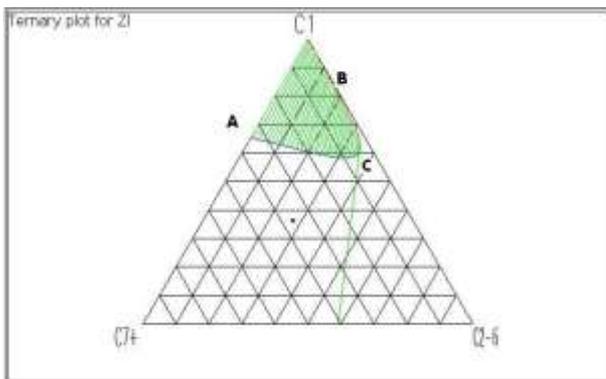


Fig. 4: Miscible displacement with rich gas injection (condensate miscibility).

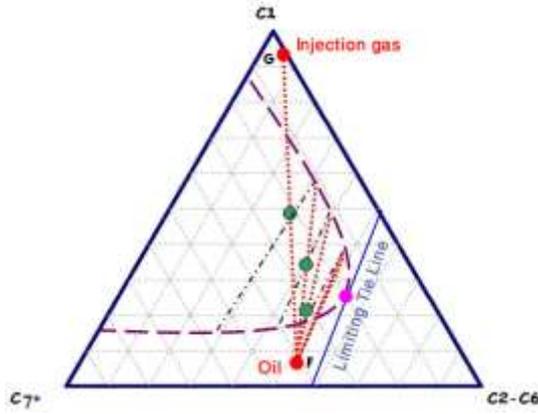


Fig. 5: shows the state where the injected fluid and reservoir fluid do not form a phase and miscible displacement will never occur.

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[Fig. 6] represents a condition in which the reservoir fluid and the injected fluid are so much close together in terms of composition that during the injection in the first contact the injected fluid and the reservoir fluid form a phase and miscible displacement will occur.

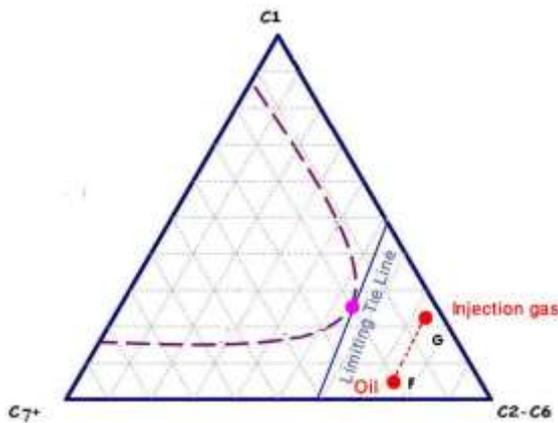


Fig. 6: Miscible displacement with the first contact between the injected gas and oil.

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Describing oil miscible process using gas injection

The mechanism of oil displacement by injecting gas that is enriched through successive contacts with oil and ultimately becomes miscible with oil reservoir is just as the displacement of a phase with a soluble phase (such as displacement of reservoir oil with LPG).

The oil recovery rate in this mode is much higher than that in other modes of displacement. The increase in the rate of oil recovery in this mode is because of the displacement of the oil existing in the reservoir. In miscible displacement, in initial contacts except for small areas of oil in pores, the remaining oil is displaced. Small areas of oil remaining are displaced through a continuous passing of fluid as well [6].

The reservoir fluid with dark surface A and the injected gas with light-colored surface D are shown in Figure 7. When gas moves to the oil reservoir, it evaporates the intermediate components in the remaining oil, and in this way, it is enriched (gray areas B and C). Higher levels intermediate components in the enriched gas causes the gray area becomes darker.

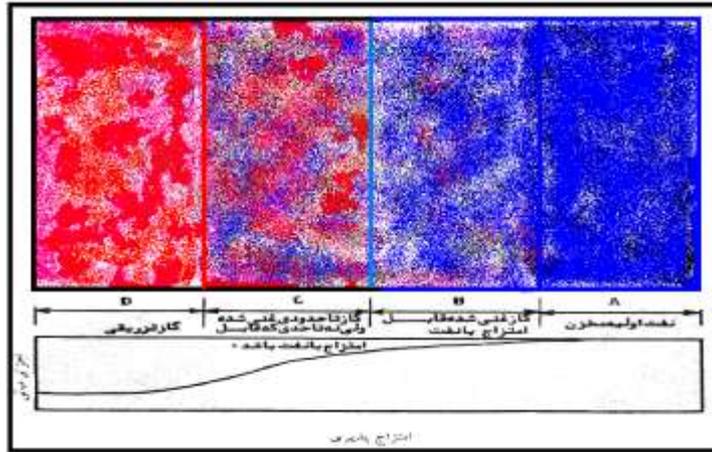


Fig. 7: Miscible gas injection process.

Small areas of oil that remain after the passage of gas in the reservoir are shown in area B. Since oil in these areas is highly similar to the miscible gas dark passing over it in terms of combination, after a while, the residual oil of area B moves with the gas. The speed of oil in this area is lower than that of the miscible fluid surrounding the oil, because oil viscosity in this area has increased due to mass transfer. In area C the two phases passing along each other are not miscible yet; thus the residual oil of this area does not move with gas. However, the evaporation of lighter components of oil causes a decrease in the volume of the oil. Finally, the ultimate residual shown in area D is very heavy, because its intermediate components have already been evaporated by gas [5].

MATERIALS AND METHODS

In this project, a simulation model has been implemented in two phases as follows:

First stage: Obtaining MMP of injected gasses including methane (CH₄), carbon dioxide (CO₂) and solvent in the first contact and in multiple contacts using software PVTi

Second stage: Examining miscible injection of methane (CH₄), carbon dioxide (CO₂) and solvent under different scenarios including different injection pressures, different injection flows and various injection compositions for the solvent gas as well as the completion method of the injection well using Eclipse-300

The results achieved in this study are graphically compared to those when the reservoir is in a natural state. Moreover, the best injection mode is select and introduced.

Examining miscible injection in the model using E-300

Description of the Model:

1. Phases in the model are formed from 3 phases of oil, gas, and water.
2. The system of Field was considered for the units of data in the model file.
3. In E300, the Adaptive Implicit (AIM) solving equations were selected.
4. The Equation of state used in the model was Soave-Redlich-Kwong (SRK) equation of state

This model is composed of 13 components which are shown by Comps key used for combined simulation.

Table 1: Combined simulation

Component name	Mole fraction
H ₂ S	0.57
CO ₂	0.63
C ₁	6.3
C ₂	2.09
C ₃	2.14
IC ₄	0.72
NC ₄	1.92
IC ₅	1.218

NC5	1.59
C6	2.56
C7+	42.4
C14+	28.5
C25+	9.3

Geological properties of the reservoir

The properties are defined in Section GRID of the data file.

Model dimensions:

1. The model has 24 cells in the direction of X, 25 cells in the direction Y and 12 cells in the direction Z.
2. The number of layers is 12, and the total number of grids is 7200.
3. The maximum amount of porosity in grids (7, 14, 9) is 0. 229879 and the minimum porosity in grids (1 3 17) is 0. 02.
4. The amount of NTG for the whole model is one.

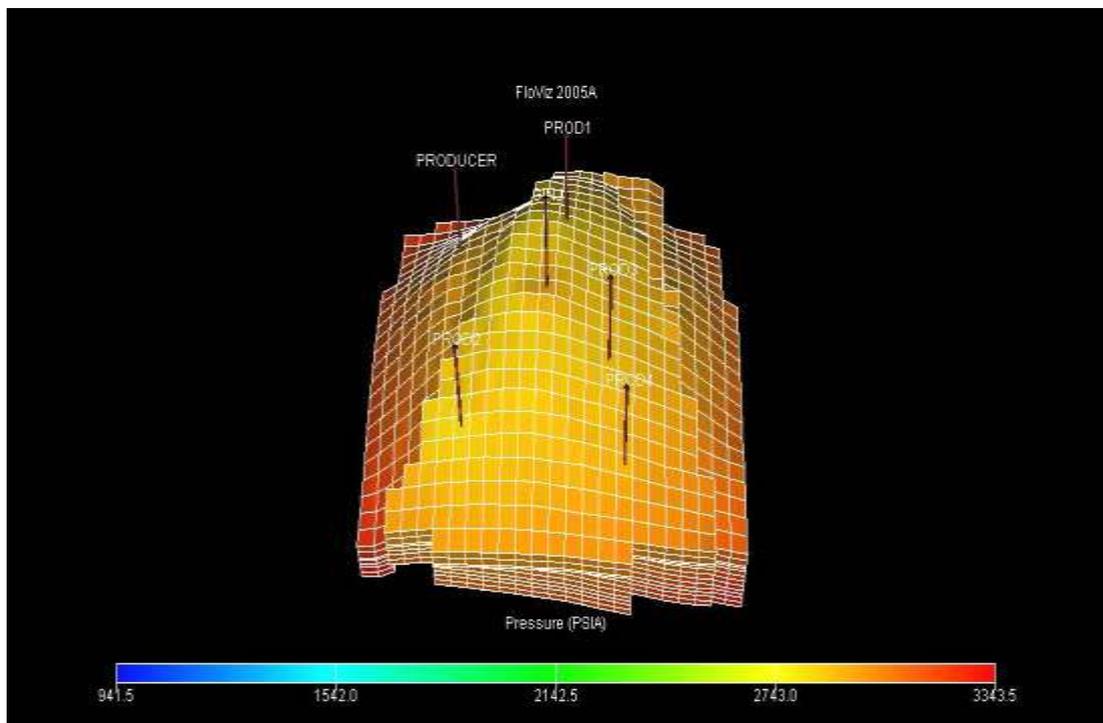


Fig. 8: 3D view of gridding of the model .

Reservoir engineering studies

1. The initial reservoir pressure at a depth of 7000 feet is 3035.7 PSIA.
2. Reservoir temperature at the gas-oil contact surface is 140 degrees Fahrenheit.
3. Water-oil and gas-oil contact surfaces are to the depth of 8200 and 7000 feet respectively.
4. The capillary pressure at water-oil and gas-oil contact surfaces is zero.
5. Bubble point pressure has been reported 1961 PSIA.

Conditions of production and injection wells in the model

Table 2: Place of production and injection wells

Wells	Location	Location	Location
Production 1	CENTER	13	8
Production 1	CENTER	7	20
Production 1	CENTER	16	16
Production 1	CENTER	17	21
PRODUCER	CENTER	6	8
Gas injection	CENTER	12	13

Types of injection gasses in the model

In this study, methane (CH₄), carbon dioxide (CO₂) and solvent were selected. The initial solvent composition was 60% of CH₄ and 40% of C₃H₈.

Control mode for production wells

Control mode conditions for production wells were as follows:

1. Oil production with initial discharge of 3000 bbl/day
2. Bottom hole pressure: 250 PSIA

Control mode for injection wells

Control mode for injection wells was based on gas injection rate of 10000 Mscf /day and bottom hole pressure of 6000 PSIA in the initial state. In addition, the injection takes place in the first to sixth layers.

Economic conditions of production and injection wells in the model

Economic constraints to production and injection wells include:

1. Maximum water cut is 0.6 STB/STB
2. Maximum GOR is 20 MSCF/day
3. Minimum oil production is 250 STB/day

Miscible gas injection in Iran’s hydrocarbon reservoirs

In fractured Hydrocarbon reservoirs, fractures have more permeability than the matrix. Accordingly, the production from fractures will be higher than that of the matrix. For example, a well within a thickness of 10 feet that has been gridded in a carbonate fractured reservoir carbonate produces oil with a flow of 3000 barrels per day, while the same production will be achieved in a non-fractured reservoir that has been gridded with a thickness of 1000 feet. The difference is only due to the presence or absence of fractures in the reservoir.

Iranian oil reservoirs have a very special state than other reservoirs in the world. In Iran, there are about 74 oil reservoirs in drought areas. Of these, 24 reservoirs have gas caps and the remaining ones are undersaturated (without gas cap). The slope of oil pressure in Iran’s oil reservoirs varies between 0.276 (psi/ft) and 0.366 (psi/ft). Formation volume factor, Bo varies from 1.314 (bbl/STB) to 2 (bbl/STB). The amount of gas solved in oil, GOR, in the range of 640 (SCF/bbl) 640 to 3497 (SCF/bbl). The lightness of oil varies from 19.1 API to 48.4 API. Oil viscosity varies between 0.3 cp and 2.5 cp 5/2.

Only about 10% of Iran's reservoirs are sandstone and 90% are carbonate reservoirs. Some reservoirs are thin and some are thick. Some of the reservoirs have strong aquifer while in some aquifer is inactive. Yet, for miscible gas injection, usually light gasses such as methane, strong gasses such as LPG, non-hydrocarbon gasses such as carbon dioxide and nitrogen are considered.

In Iran, all gas injection projects that have been done using the immiscible injection method to stabilize the reservoir pressure (injection of dry gas in the gas cap). The only case of miscible gas injection is the gas injection project in Ramshir reservoir that has been in operation for about 15 years. However, this reservoir is too small compared to other reservoirs in Iran, and therefore it has been set as a pilot plant. Miscibility conditions have been set to be provided in the reservoir by NGL gaseous liquids. Hence,

examining miscible gas injection in Iran's carbonate reservoirs is among the first projects of miscible gas injection in carbonate reservoirs in the world.

The evaluation of miscible gas injection in Iran's carbonate reservoirs entails an analysis of the following basic questions:

- What criteria are there for miscible gas injection into Iran's oil reservoirs?
- What type of gas should be considered for miscible injection in Iran's oil reservoirs?
- Which Iranian oil reservoirs are appropriate for miscible gas injection?
- How much will the amount of oil recovery be by miscible gas injection?
- What effect will size and shape, fracturedness, heterogeneity of rock in terms of porosity and permeability, slope of building, nature of gas and oil, temperature and pressure conditions and saturation in the reservoir have on the efficiency of miscible injection in Iran's oil reservoirs?

Obviously, answers to the above questions help clarify the method for miscible gas injection into Iran's oil reservoirs, which is promising as a secondary production of oil.

In this study, the model was run for 24 years from 2007 until 2031 and the results were evaluated

RESULTS

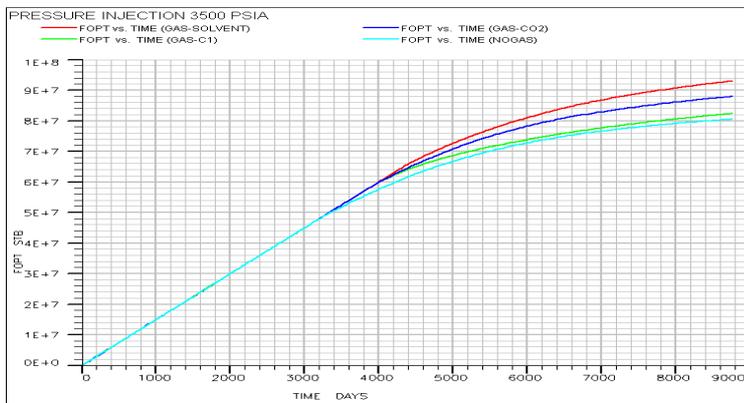
Research scenarios

The first scenario

In the first scenario, methane (CH₄), carbon dioxide (CO₂), and Solvent were injected into the reservoir at a pressure of 3500 (PSIA).

The injection process requires that the minimum injection pressure be higher than the reservoir pressure, which is 3035 (PSIA). Therefore, the minimum pressure of 3500 (PSIA) was selected to enhance the recovery of oil by injection of solvent, CO₂, and C₁.

As could be seen in the diagrams, the higher level of oil production (FOPT) and the lower amount of gas production (FGPT) were respectively under the effect of solvent injection higher than CO₂ and CO₂ injection higher than CH₄.



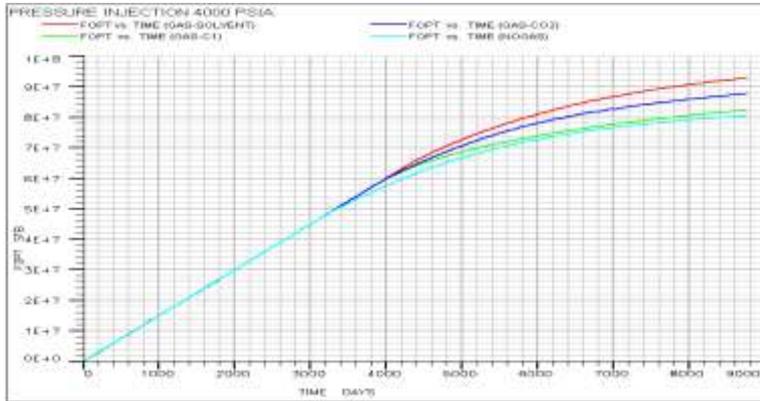
FOPT diagram of the first scenario at 3500 (PSIA).



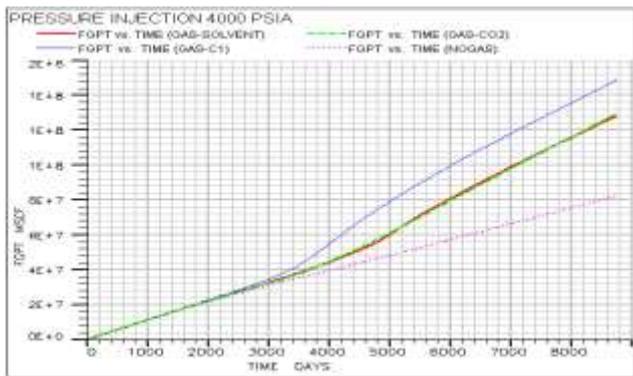
FGPT diagram of the first scenario at 3500 (PSIA).

The second scenario

In the second scenario, first the injection of methane (CH₄), carbon dioxide (CO₂) and solvent took place at a pressure higher than the first scenario in injection pressure of 4000 (PSIA). The results were presented as diagrams and compared to the case when the reservoir was in the natural discharge state. The results showed that oil production (FOPT) slightly increased for CH₄, but no change was observed for Solvent and CO₂ compared with the pressure of 3500 (PSIA) in the first scenario. Gas production rate (FGPT), for CH₄, CO₂, and Solvent increased compared to the 3500 pressure (PSIA) in the first scenario.



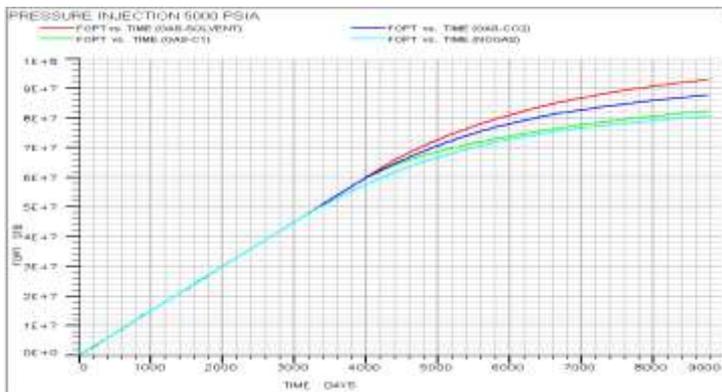
FOPT diagram of the second scenario at 4000 (PSIA).



FGPT diagram of the second scenario at 4000 (PSIA).

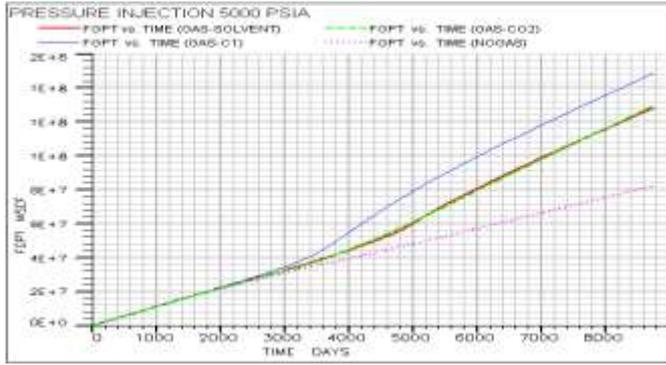
The third scenario

In the third scenario, injection of methane (CH₄), carbon dioxide (CO₂) and Solvent took place at the injection pressure of 5000 (PSIA) which was higher than the MMP. The results showed that oil production rate (FOPT) and gas production rate (FGPT) did not change compared to the pressure of 4000 (PSIA) in the second scenario.



FOPT diagram of the third scenario at 4000 (PSIA).

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FGPT diagram of the third scenario at 4000 (PSIA).

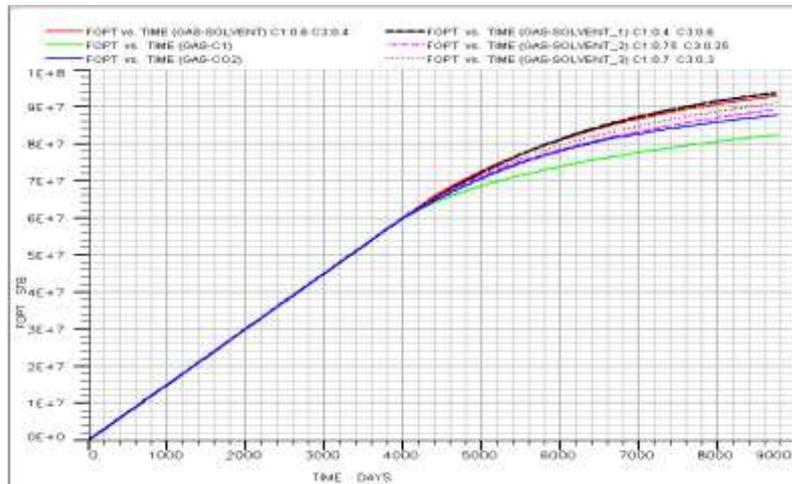
The fourth scenario

The fourth scenario includes the Solvent injection modes passed through a variety of gas compositions including methane and propane, compared to the initial Solvent composition equal to 60% of CH₄ and 40% of C₃H₈. The results are presented in [Table 3].

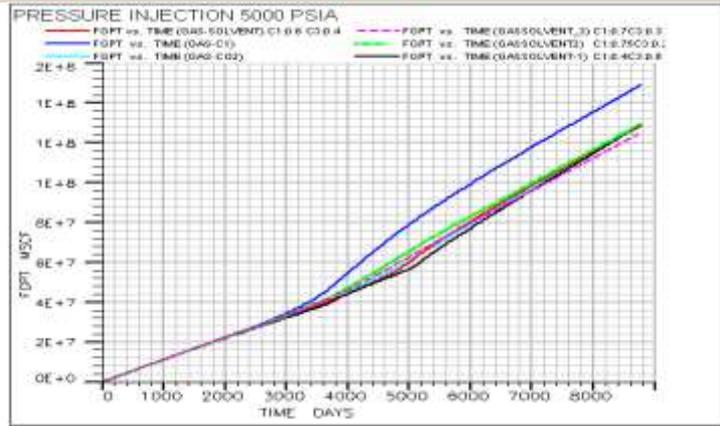
Table 3: Different compositions of Solvent

Solvent	CH ₄ %	C ₃ H ₈ %
First mode	0.75	0.25
Second mode	0.7	0.3
Third mode	0.4	0.6

In examining Solvent injection with different compositions it could be concluded that if the percentage of propane (C₃H₈) in Solvent (gets richer) increases, oil production rate increases because the injection combination of oil and gas are closer to each other and miscibility occurs more easily. Among the injection of various compounds listed above, Solvent with the percentage 60-40 has the highest rate of oil production due to higher levels of propane (C₃H₈) and higher levels of enrichment.



FGPT diagram of the fourth scenario.



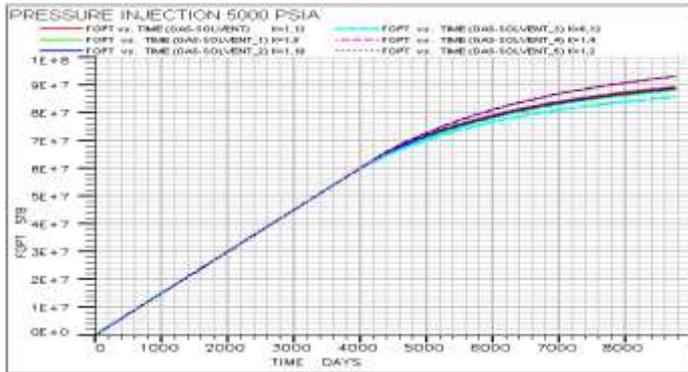
FGPT diagram of the fourth scenario.

The fifth scenario

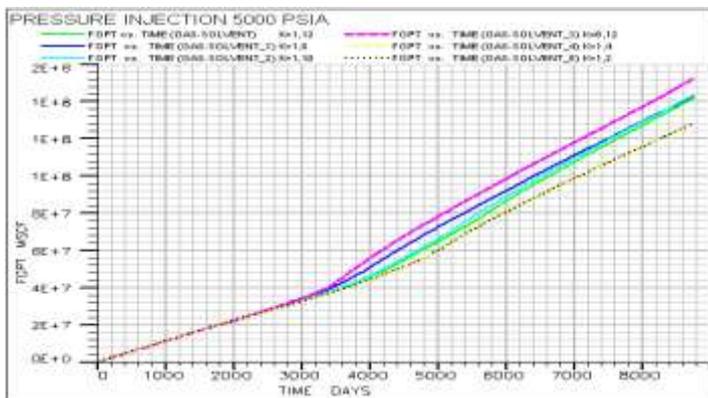
The states of the completion layers of the injection well are studied in this scenario. To this end, the injection well has been gridded in different layers (K) [according to Table 4] for Solvent at the injection pressure of 5000 (PSIA).

Table 4: Gridding of layers

K=1	K=2
K=1	K=4
K=1	K=8
K=1	K=10
K=1	K=12
K=6	K=12



FOPT diagram of the fifth scenario.



FGPT diagram of the fifth scenario.

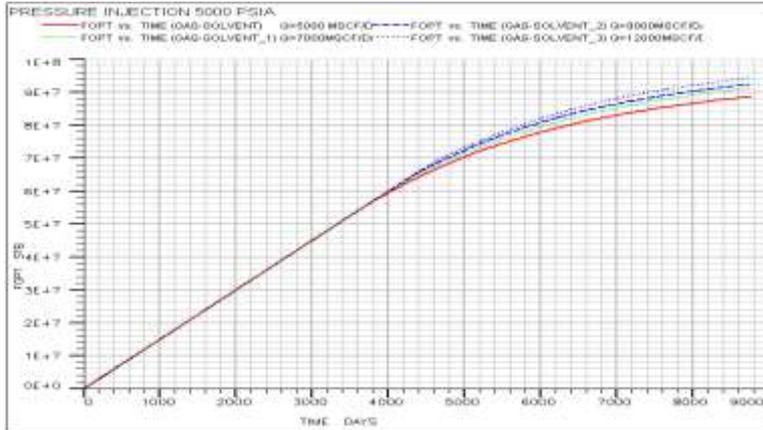
The results show that if the injection takes place in higher layers, oil production increases while gas production decreases.

The Sixth scenario

In this scenario, Solvent injection was performed at the pressure of 5000 (PSIA) in different injection flows as described below:

- MSCF/day-15000
- 2 MSCF/day 7000
- 3 MSCF/day 9000
- 4 MSCF/day 12000

According to the following diagrams, it could be concluded that increasing the injection flow does not lead to higher oil production, but up to a certain level of increase in the injection flow will follow higher oil production, while higher levels cause an increase in gas production which leads to double pressure drop of the oil reservoir.



FOPT diagram of the sixth scenario.



FGPT diagram of the sixth scenario.

DISCUSSION AND CONCLUSION

According to simulations carried out by software PVTi and E300 on the defined models, the following results were achieved:

On examining the MMP, Solvent having the lowest miscibility pressure (4808) and carbon dioxide (CO₂) having the highest miscibility pressure (14670) took place in the first contact. In addition, on examining the miscibility pressure, CO₂ having the lowest miscibility pressure (2991) and methane (CH₄) with the highest miscibility pressure (4324) took place in multiple contact.

According to the results of the scenarios above, MMP calculated for injection gasses, the most appropriate injection pressure for achieving more production of oil is the pressure of 4000 (PSIA). In addition, in examining the injection of Solvent with different compositions, it could be concluded that if the percentage of propane (C₃H₈) in Solvent increases (gets richer), oil production rate increases because the injection combination of oil and gas are closer to each other and miscibility occurs more easily.

In examining the completion of injection well, according to the results it could be concluded that if the injection takes place in higher layers, oil production increases while gas production decreases.

It could also be concluded that increasing the injection flow does not lead to higher oil production, but up to a certain level of increase in the injection flow will follow higher oil production, while higher levels do not cause an increase in oil production.

In this study, Solvent was the most appropriate gas for injection into oil reservoirs due to low miscibility, higher oil production and lower gas production.

CONFLICT OF INTEREST

There is no conflict of interest.

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None

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