Immiscible-Recycle Gas Injection to Enhance Recovery in an Iranian Naturally Fractured Reservoir: a Case Study with Emphasis on Uncertain Parameters

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Recycle-gas injection is a promising recovery process to produce oil and gas. The method uses continues injection of the produced gas at economical rates to keep the reservoirs energy up and using viscous force as the driving force. There are numerous studies done on recycle-gas injection in conventional reservoirs, however, there are some other factors such as location of wells and completion type, rate and pressure of injection which highly affect the final result of this method and failed to be considered in the majority of them.

In this study, we investigate the immiscible recycle gas injection process in one of the Iranian carbonate naturally fractured reservoirs on a field scale. The real heterogeneous model was constructed and simulated by Eclipse-100 module. The effects of operational parameters, such as number and location of injection/production wells, production/injection rate, completion type and interval, on the immiscible gas injection performance were investigated and the result were compared with natural depletion method.

It was found that, in sensitivity with number of the wells, 1 injection/2 production wells was the most efficient case. Also well oil production rate of 3 145 bbl/d (500 m³/d) and well bottom-hole pressure of 25 bar provided higher oil recovery. Completing of the injection wells in fracture and production wells in matrix has a better field oil efficiency in comparison to the other cases. Moreover, it was observed that the most efficient type of well completion for injection well is vertical and for production wells are horizontal. The results revealed that the substantial secondary oil recovery can be achieved using optimum conditions for immiscible recycle gas injection in this reservoir.

Key words: Immiscible-recycle gas, fractured reservoirs, secondary recovery, operational parameters

1. Introduction

In conventional oil recovery projects, the decline of primary production to an uneconomic level led to the development of various schemes to improve the oil recovery efficiency before abandonment of a reservoir. The term enhanced oil recovery (EOR) principally refers to the recovery of oil by any method beyond the primary stage of oil production. It is defined as the production of crude oil from the reservoirs through processes taken to increase the primary reservoir drive. These processes may include pressure maintenance, injection of displacing fluids, or other methods such as thermal techniques. Therefore, by definition, EOR techniques include all methods that are used to increase cumulative oil produced (oil recovery) as much as possible.[1]

Enhanced oil recovery can be divided into two major types of techniques: thermal and non-thermal recovery. Non-thermal recovery methods can be split into: water flooding, gas injection (including: LPG miscible slug, enriched gas miscible process, high pressure lean gas miscible process, carbon dioxide process) and chemical processes (including: micellar polymer flooding, caustic flooding, polymer flooding). Thermal recovery refers to oil recovery processes in which heat plays the principle role. The most widely used thermal techniques are in situ combustion, continuous injection of hot fluids such as steam, water or gases, and cyclic operations such as steam soaking.[5]

In gas injection processes there are two main types of gas injection, miscible gas injection and immiscible gas injection. In miscible gas injection, the gas is injected at or above minimum miscibility pressure (MMP) which causes the gas to be miscible in the oil. On the other hand in immiscible gas injection, flooding by the gas is conducted below MMP. This low pressure injection of gas is used to maintain reservoir pressure to prevent production cut-off and thereby increase the rate of production.[3] The combination of light crude, relatively high reservoir temperature, and relatively low reservoir pressure favored immiscible gas injection as the most suitable EOR process.[4] The previous studies have shown that immiscible crestal gas injection had potential for increasing oil recovery by the following mechanisms:

- An alternate reservoir energy source can be created in the secondary gas cap to diminish the effects of the aquifer. Pressure increase on the crest can slow or neutralize the advance of water.
- Gas displaces oil more efficiently than water. The end-point recovery by gas is 50 percent compared to 30 percent by water.

- Vertical displacement of oil bye gas, with gravity segregation forces, will add to the incremental recovery.
- Oil swelling and viscosity reduction will contribute to improved oil recovery.[6]

Injection of a fluid such as water or gas, under appropriate conditions, has become the usual practice to recover additional oil after primary production. These methods, commonly known as secondary recovery methods, usually recover 5-20% of remaining oil after primary production. However these fluids, being immiscible with the reservoir oil, leave high residual oil saturation, (40% - 60% OOIP) after displacement. Gas recycling has been recommended for several years as a favorable production scenario for pressure maintenance as well as producing unrecovered oil reserves. Typically, in this method a number of injection wells are drilled and a fraction of produced field gas or gases from other resources are injected into the reservoirs.

In this work, we used commercial simulator, *ECLIPSE*, to simulate immiscible recycle gas injection in a specific sector, which is a quarter of one of the most important Iranian south-west oil reservoirs. Phase behavior of the reservoir fluid was modeled by *PVTi* module of *ECLIPSE* package using Peng-Robinson EOS. The optimized parameters in this work are the location and number of the wells and injection/productionparameters. Finally, an optimum condition for gas recycling in this reservoir was proposed.

2. Simulation Study of immiscible gas injection

2.1 Reservoir fluid properties

The reservoir fluid is light oil with the API of 41 supplied from one of the Iranian south-west oil reservoirs. Initial state of reservoir and properties of the reservoir fluid as well as constrains which should be applied are presented in Tables 1-3.

Table 1. Initial reservoir conditions

Initial reservoir pressure	2 465.6 psi
Reservoir temperature	128 °F
Initial water-oil contact	3 117 ft S.S
Initial gas-oil contact	1 640 ft S.S

Table 2. Physical properties of reservoir oil

Bubble point pressure(psi)	° API	Viscosity (cP)
1960.9	41	0.59

Table 3. Constrains in simulation

Minimum BHP	362.6 psi
Maximum GOR	821 ft³/stb
Maximum WCT	0.05

2.2 Description of the Model

In this simulation study, we are going to model the reservoir with commercial software, *ECLIPSE*. Cartesian coordinates with corner point geometry were selected for construction of the model. Dual porosity and dual permeability behavior was chosen for better representation of the fracture system. Fully implicit pressure solution method was agreed to be used. Grid model and properties are shown in Figure 1 and Table 4, respectively.

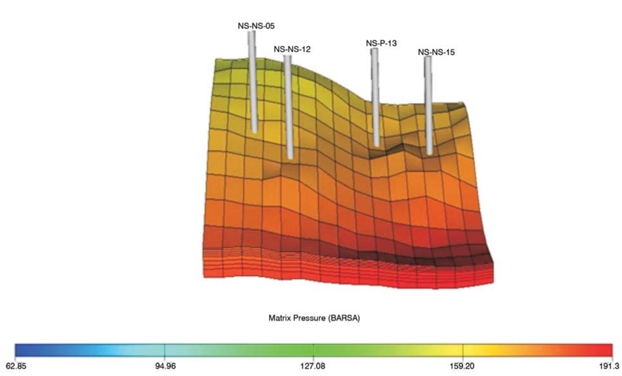

Fig. 1. Static model of the reservoir constructed by simulator
Sl. 1. Statički model ležišta napravljen pomoću simulatora

Table 4. Reservoir characterization in the simulation

No of cells in X direction(NX)	10	Grid size in Z direction (DZ, ft)	9-62
No of cells in Y direction(NY)	15	k_X(mD)	0.7-99.2
No of cells in Z direction(NZ)	8	k_Y(mD)	0.7-99.2
Grid size in X direction(DX, ft)	569-578	k_Z(mD)	0.6-89.3
Grid size in Y direction (DY, ft)	569-577	Porosity (fraction)	0.09-0.179

Precise and accurate characterization of a reservoir fluid is an imperative factor in reservoir simulation studies. In gas flooding processes, because of existence of a great interaction between injected and in place fluids, it is very important to characterize the reservoir fluid precisely. PVT experiments are usually expensive and time consuming performed in limited conditions. Therefore, EOS based PVT packages are used widely for the prediction and evaluation of fluid properties in well and surface conditions over a wide range of temperature, pressure and composition.[2] Here, using *PVTi* module of *ECLIPSE*, three parameter Peng-Robinson EOS which predicts the behavior of the Iranian reservoirs' fluid quite well, was tuned to present fluid sample of the reservoir. Lohrens-Bray-Clark (LBC) was used as viscosity correlation. For whole of the reservoir, just one composition was considered. Amongst different available PVT samples, the one which describes behavior of the reservoir fluid better and accords the most with real data was taken as reservoir fluid representative. Components defined in *PVTi* and EOS was tuned without any grouping since in a non-compositional run no grouping is needed. The results of the tuning process for the liquid viscosity and oil relative volume, relative permeability and capillary pressure of oil-water and oil-gas systems that will be used in this study are given in Figures 2 to 3, respectively. After inserting the petrophysics, PVT and initialization data in the model, and also rock-type determination of the grids (that depends on the grid porosity and initial water saturation), the model is ready for various studies.

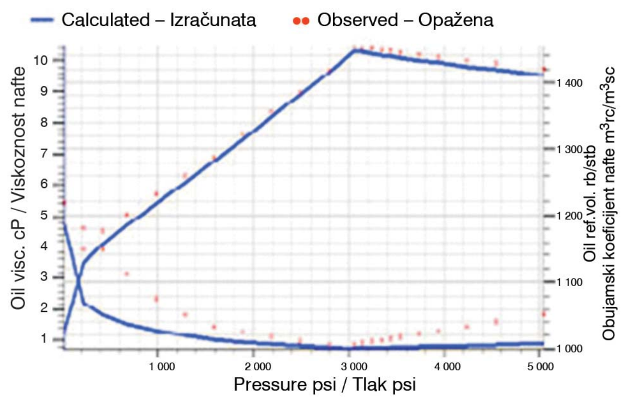

Fig. 2. Comparison of calculated and observed oil viscosity and relative volume
Sl. 2. Usporedba izračunatih i opaženih viskoznosti nafte i relativnog volumena (obujamskog koeficijenta)

4. Results and Discussions

4.1 Natural Depletion

This sector of the reservoir would produce from year 1935 up to 2005 when producing wells shut down. Following information are available from the field production data during natural depletion:

- The sector ultimate oil recovery in natural depletion will be 34.01% after 70 years of oil production.
- Initial reservoir pressure is around 170 bar and finally after 70 years of oil production, it reduces to 67.63 bar. At the early production times, field pressure rate decreases sharply.
- During this production scenario, the field initial production rate is around 3 000 bbl/d (477 m^3/d). Around year 1972 one production well shut down and 8 years later one more well was stop from production, and by the end of 1999 all of the wells were closed in this sector. At year 2004 just one well went on production but at year 2005 this well also shut down. There is a sharp decline of oil production rate from year 1998.
- This sector produces negligible water during natural depletion interval.

This sector is a good candidate for EOR processes after 70 years of oil production; therefore, we study the immiscible gas recycling scenario in this reservoir.

4.2 Immiscible Recycle Gas Injection Scenario

Here, the method of immiscible recycle gas injection has been simulated. This production strategy has resulted in better efficiency and therefore higher oil recovery and good economics. The simulation results illustrate the influences of immiscible recycle gas injection on recovery efficiency. In this scenario, the field produces naturally

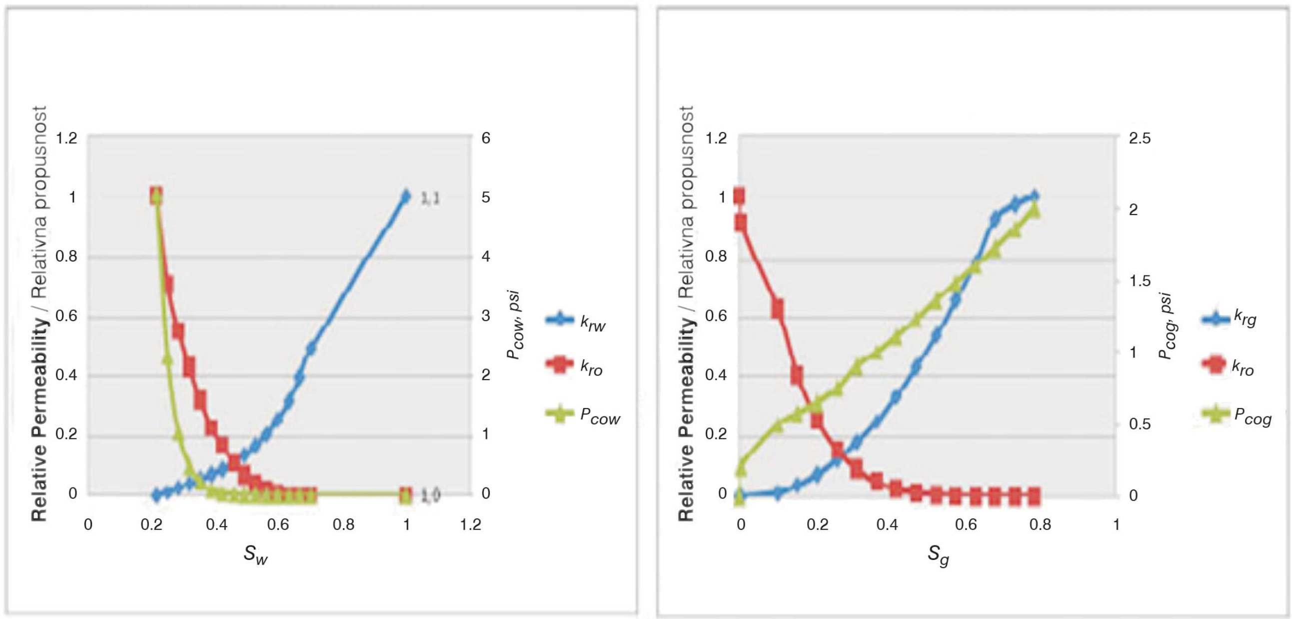

Fig. 3. Relative permeability and capillary pressure of Oil-Water and Oil-Gas
Sl. 3. Relativna propusnost i kapilarni tlak nafta-voda i nafta-plin

until 2020; we implement EOR scenario from year 2005 for 15 years.

4.2.1 Sensitivity Analysis with the number of the wells

In this part, we use different number of wells and compared the results with each others. We have investigated the effect of number of wells on the efficiency of both natural depletion and gas recycling mechanisms. With increasing the number of wells, the recovery factor increases. If the recovery factor is stable with increasing the number of wells, the optimum number of wells is obtained. Some of the best different cases that are selected for evaluating the influence of the number of wells on the recovery are given in Table 5 and Figure 4. From the results, 1-injection/3-production pattern has the highest efficiency and after that 1-injection/2-production pattern is the most efficient case, but in the first case the fluctuation in GOR of producing wells is high. Thus we choose the case 1-injection/2-production as the most favorable one in this part.

Table 6. Well locations

Configuration No.	Inj-01		Prod-01		Prod-02		Field oil efficiency
	I	J	I	J	I	J	
1	16	76	17	71	19	65	0.611 633
2	18	68	17	71	19	65	0.602 792
3	20	62	17	71	19	65	0.603 094
4	15	69	17	71	19	65	0.602 978
5	18	74	17	71	19	65	0.603 783
6	16	76	17	71	19	65	0.611 633
7	16	76	18	68	20	63	0.563 874
8	16	76	17	73	19	67	0.619 683
9	16	76	18	72	20	65	0.605 567

4.2.2 Effect of Wells Location on Oil Recovery Efficiency

The location of the injection wells was optimized by different factors such as permeability, transmissibility, porosity, and oil saturation distributions. By considering mentioned factors, we try different patterns in this sector for optimizing well locations for the previous section (1-Injection/2-Production). Different configurations and the related FOE of each of which are presented in Table 6. By comparison of different well's location, we propose the configuration-9 which has a higher performance than the other cases.

Table 5. Number of wells and Field Oil Efficiency

Number of wells	Maximum FOE	Average field pressure (bar)
Natural Depletion	0.507 0	29.00
1 Inj. - 1 Prod.	0.503 918	89.70
1 Inj. -2 Prod.	0.611 633	83.50
2 Inj. -2 Prod.	0.610 4165	83.50
1 Inj. -3 Prod.	0.612 399	90.30

4.2.3 Optimization with respect to Injection-Production Parameters

4.2.3.1 Production Rate

Here, we check different production rates for both wells (PRO-01 and PRO-02). The results are shown in the Table 7 and Figure 5. From the table, we can see that two cases; WOPR=500 m^3/d and WOPR=700 m^3/d have higher efficiency in comparison to the others cases. But, with WOPR=700 m^3/d, the instability in GOR of both wells is very high with respect to case which WOPR=500 m^3/d, and in the second case well produce up to year 2019, which in the first case (WOPR=700 m^3/d) well shut down in year 2005; so in this part, we suggest the case in which WOPR is 500 m^3/d.

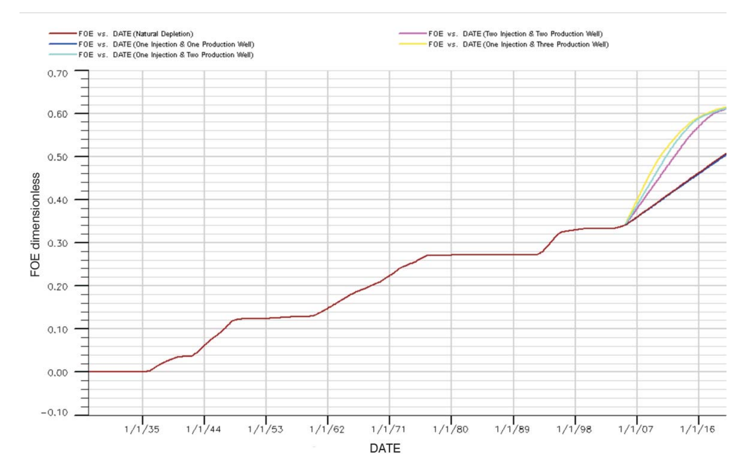

Fig. 4. Field oil efficiency for different number of wells
Sl. 4. Iscrpak nafte za različiti broj bušotina

Table 7. Sensitivity analysis on production rate

Rate(m^3/d)	Field oil efficiency
300	0.536 295
500	0.6263 04
600	0.625 435
700	0.626 248

4.2.3.2 Production Wells Bottom Hole Pressure (WBHP)

We selected four different cases to investigate the effect of bottom-hole pressure on recovery efficiency (presented in the Table 8). Generally, the higher bottom-hole pressure as a constrain for controlling the production, leads to more oil residue in a reservoir; thereupon, it reduces the

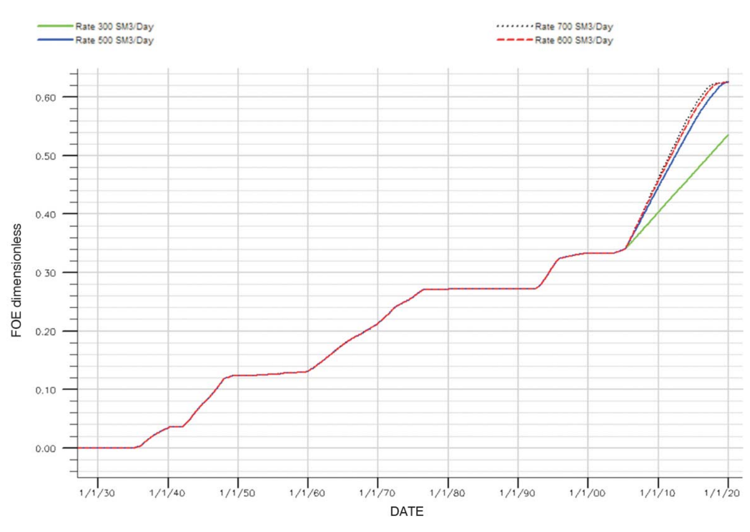

Fig. 5. Field oil efficiency for sensitivity analysis on rate
Sl. 5. Iscrpak nafte prema analizi osjetljivosti na količinu proizvodnje

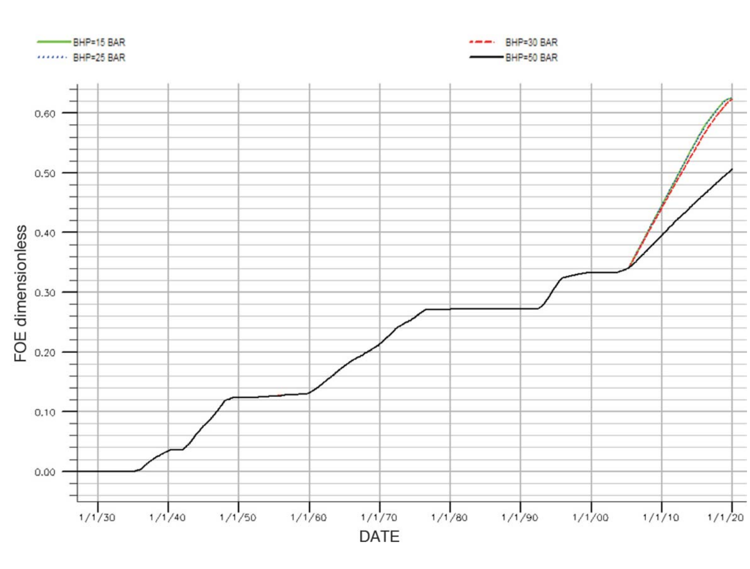

Fig. 6. Field oil efficiency for sensitivity analysis on production well bottom hole-pressure
Sl. 6. Iscrpak ležišta prema analizi osjetljivosti proizvodnje s obzirom na tlak na dnu bušotine

Table 8. Sensitivity analysis on production well bottom hole-pressure

Case	WBHP (bar)	Field oil efficiency
1	15	0.624 47
2	25	0.626 304
3	30	0.623 864
4	50	0.506 589

recovery factor. By optimizing this parameter, value of 25 bar was selected as an optimum well bottom-hole pressure. At this WBHP, FOE has the maximum value, as it is shown in the Figure 6.

4.2.3.3 Sensitivity Analysis on Completion Interval

Oil recovery efficiency depends strongly on the completion interval of injection and production wells. Since this oil field is a fractured reservoir, we simulate this sector by dual-porosity, dual-permeability option of *ECLIPSE* simulator. To complete the wells, we can complete injection and production wells in matrix and fracture parts of the reservoir. We try this at different conditions. At first, we complete injection wells in fracture and production wells in matrix, and then try this conversely. For the third case, we complete both injection and production wells in the matrix and finally completes them in fracture. Results of this part of simulation are given in Table 9 and 10. As we can see in the Table 9 and 10, completing injection well in fracture and production wells in matrix has a better field oil efficiency.Because completing of injection wells in matrix causes injected gas or fluid move swiftly toward fracture and result in low sweep efficiency, but if we complete injection wells in fracture the injected fluid or gas sweep the unrecovered oil in a better shape, and it results better areal/volumetric sweep efficiency. Thus, we select completion of injection well in fracture and production well in matrix in this section.

Table 9. Field oil efficiency for sensitivity analysis on completion interval for injection well

Completion intervals	Field oil efficiency
Fracture 9-12	0.619 218 3
Matrix 2-5	0.619 559 6
Matrix 5-8	0.619 272 6
Fracture 11-15	0.619 683
Matrix 3-6	0.619 553 7

Table10. Field oil efficiency for sensitivity analysis on completion interval for production wells

Completion intervals		Field oil efficiency
Production Well-1	Production Well-2	
Matrix 3-6	Matrix 3-6	0.619 683
Matrix 5-8	Matrix 5-8	0.619 673
Fracture 9-12	Fracture 9-12	0.579 878
Fracture 12-15	Fracture 12-15	0.604 092
Fracture 12-15	Matrix 3-6	0.614 066

4.2.3.4 Sensitivity Analysis on Completion Type

Three different type of well completion (vertical, horizontal, deviational) were analyzed for both production and injection wells. To do this, we first changed the completion type of the injection well while we keep the completion type of production wells as vertical. Then, we changed the completion type for production wells to determine the best type for them. FOE for different well completion types for injection wells are given in table 11. The results show no considerable difference between the FOE for horizontal and vertical wells; hence, due to the higher cost and difficulties of horizontal wells, we choose vertical completion type for injection wells.

Table11. Field oil efficiency for sensitivity analysis on completion type for injection well

Well completion type	Field oil efficiency
Vertical	0.619 683
Horizontal (layer 12 - I Direction)	0.619 33
Horizontal (layer 12 - J Direction)	0.619 812 9
Directional (Layers 10-14 - J Direction)	0.619 764 98

For production wells, first we optimize each type of completion and then we compare the results to find the best one. As we can see in table 12, completion of horizontal wells in layer 6 will result in higher FOE.

Table12. FOE for sensitivity analysis on horizontal completion in different layer for production wells

Layer number	Field oil efficiency
3	0.516 252 3
5	0.613 651 6
6	0.626 304
7	0.340 127 1

The FOE values for different directional completion will show the same result as given in table 13.

Table13. FOE for sensitivity analysis on directional completion in different layer for production wells

Directional completion for production wells	
Completion layers	Field oil efficiency
5-6 in J Direction	0.625 753
5-6 in I-J Direction	0.621 417

Finally, we selected the horizontal completion for production wells due to its higher FOE in comparison with vertical and directional completion (Table 14).

Table14. FOE for sensitivity analysis on different completion type for production wells

Well completion type	Field oil efficiency
Vertical	0.619 683
Horizontal	0.626 304
Directional	0.625 753

4.3 Optimum Immiscible Recycle Gas Injection Conditions

Finally, during different parts through this work, we propose optimum conditions for immiscible recycle gas injection implemented in this sector. Optimum well numbers are one injection well (Inj-01) and two production wells. Locations, completion intervals and type of completion of these wells are listed in the Table 15. Parameters of production and injection are given in the Table 16.

Table 15. Location of injection and production wells

	Injection well		Production well-1		Production well-2	
Well locations	I	J	I	J	I	J
	16	76	17	73	19	67
Completion intervals	Fracture 11-15		Layer 6		Layer 6	
Type of Well Completion	Vertical		Horizontal		Horizontal	

Table 16. Parameters of production and injection

Maximum BHP of injection well (bar)	175
Minimum BHP of production wells (bar)	25
Production rate of production wells (sm^3/Day)	500
Injection well control mode	GRUP (item 4 in keyword WCONINJE)

5. Conclusions

The following conclusions can be drawn from this work:

- Immiscible recycle gas injection can be a good candidate as an EOR scheme for implementation for various reservoir conditions.
- Location of the injection/production wells was optimized by different factors such as permeability, transmissibility, porosity, and oil saturation distributions.
- After sensitivity analysis, two production wells and one injection well has been proposed as the optimum number of wells for this sector of the reservoir.
- Generally, for completion intervals, we recommend completion of injection well in fracture and production wells in matrix.
- Vertical and horizontal completion type was selected respectively for injection and production wells based on FOE value and economical costs considerations.

- The gas injection rate was found to have considerable effects on the reservoir recovery so that by reducing the gas injection rate, the recovery factor also decreases.
- It has been shown that, the recovery factor form 50.70% during the natural depletion has increased to about 62.63% during the gas recycling.
- Reservoir communication and lateral connectivity are important elements to demonstrate the feasibility of any gas flooding development plans; interference test must be performed between wells of reservoir to demonstrate pressure and fluid communication between available wells.
- The present study was an immiscible process. So, for finding the miscibility conditions, several slim tube displacement experiments should be performed.

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