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ORIGINAL PAPER - PRODUCTION ENGINEERING

Performance of the injection of different gases for enhanced oil recovery in a compositionally grading oil reservoir

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Abstract

Reservoir fluid characterization is one of the most important steps in hydrocarbon reservoir engineering calculations and studies. The reservoir fluid composition is not constant along the entire hydrocarbon column and varies along the vertical and horizontal directions. In most cases, such variations have been observed along the vertical direction. This is known as compositional grading phenomenon and has a strong impact on the calculation of original hydrocarbon in place, reservoir development, and oil recovery factor. In this paper, a simulation study was carried out to investigate the effects of compositional grading on reservoir fluid properties and the injection of various gases such as carbon dioxide (CO_2), nitrogen (N_2), associated petroleum gas (APG), N_2–CO_2 mixture, and water-alternating-CO_2 injection into different depths of a conventional black oil reservoir in the southwest of Iran in order to detect the best injection depth and achieve the highest oil recovery factor. Due to increase in minimum miscibility pressure (MMP) with depth in compositionally grading reservoirs, MMP variations with depth is one of the main challenges in determining the optimal gas injection depth in such reservoirs. The results showed that N_2, APG and N_2–CO_2 mixture were immiscibly injected into all depths of the reservoir due to their high miscibility pressures. The occurrence of gas override and channelling phenomena during the course of immiscible gas injection significantly reduced oil displacement efficiency. On the other hand, CO_2 was miscibly injected to all reservoir layers and revealed a higher efficiency in comparison with the injection of N_2, APG and N_2–CO_2 mixture. In fact, better miscibility development was observed in upper reservoir parts, as compared to the lower parts. Through completing injection wells at upper reservoir parts and then injecting gas into these parts, one can thus further enhance oil recovery and extend production plateau. Moreover, the results confirmed that water-alternating-CO_2 injection into all reservoir depths, compared to other gas injection scenarios, was associated with increased macroscopic sweep efficiency as well as enhanced oil recovery factor.

Keywords Compositional grading · STOOIP · Gas injection · MMP · Oil recovery factor

Abbreviations

APG	Associated petroleum gas
CCE	Constant composition expansion
CGR	Condensate gas ratio
CO_2	Carbon dioxide
DL	Differential liberation
EOR	Enhanced oil recovery
EOS	Equation of state
GOC	Gas oil contact
H_2S	Hydrogen sulphide
IFT	Interfacial tension
MMP	Minimum miscibility pressure
MMSCFD	10^6 standard cubic feet per day
MMMSCF	10^9 standard cubic feet
N_2	Nitrogen
OFVF	Oil formation volume factor
OGIP	Original gas in-place
OOIP	Original oil in-place
PVT	Pressure volume temperature
SCF	Standard cubic feet
STB	Stock tank barrel
STBD	Stock tank barrel per day
STOOIP	Stock tank original oil in-place
VGD	Vaporizing gas drive
WAG	Water alternating gas
WOC	Water oil contact

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Introduction

In hydrocarbon reservoirs, compositional grading phenomenon leads to variations in reservoir fluid composition. It causes alterations in reservoir oil and gas composition along the vertical and, in some cases, horizontal directions. Due to their non-equilibrium thermodynamic conditions, a majority of the hydrocarbon reservoirs around the world, particularly reservoirs of large thickness and high dip, are engaged in compositional grading (Hussein and Mahgoub 2005).

Compositional grading largely contributes to the determination of the gas–oil contact (GOC), original oil in-place (OOIP) and original gas in-place (OGIP), gas and oil production forecast, surface production facilities design, and miscible and immiscible water and gas injection process for enhanced oil recovery (Høier 1997; Barrufet and Jaramillo 2004; Kord and Zobeidi 2007; Wheaton 1991). In immiscible gas and water injection processes, such a phenomenon leads to mobility variations with depth; however, when it comes to miscible gas injection, it causes miscibility variations at different depths (Høier 1997).

Many factors (namely gravitational force, thermal diffusion, natural and thermal convection, molecular diffusion, migration or incomplete mixing of hydrocarbons within a reservoir, and asphaltene precipitation) contribute to compositional grading in hydrocarbon reservoirs (Ghorayeb and Firoozabadi 2001, Nikpoor et al. 2011). Among these factors, gravitational force and thermal diffusion have the greatest impacts on compositional grading in reservoir (Dougherty Jr and Drickamer 1955).

In the thick reservoirs, with increasing depth and due to gravitational force, the light and heavy components of reservoir fluid tend to be separated from one another and move towards the top and bottom of the reservoir, respectively (Sage and Lacey 1939; Whitson and Belery 1994). The presence of thermal diffusion in the reservoir, however, makes the light components of reservoir fluid move towards the lower parts and the heavy fluid components move towards the upper parts of the reservoir (Bedrikovetsky 1993).

In fact, lighter components existing in the fluid in higher parts of the reservoir tend to move towards lower regions (where the temperature is higher), while heavier components in deeper reservoir regions tend to move upward (where the temperature is lower), giving rise to phase inversion phenomenon (Whitson and Belery 1994).

The temperature gradient reduces the effect of the gravitational force on compositional grading; however, it is less effective than the gravitational force (Høier and Whitson 2000). In general, temperature variations might reduce, increase, balance or eliminate the effects of gravity on the compositional grading phenomenon in a reservoir (Whitson and Belery 1994).

Compositional grading can also develop in gas reservoirs. Temeng et al. (1998) investigated the compositional grading in a carbonate gas reservoir (Ghawar Khuff) and observed that all hydrocarbon components of the reservoir gas, dew point pressure, and condensate-to-gas ratio (CGR) decreased with increasing depth; however, non-hydrocarbon gas components such as carbon dioxide (CO_2), nitrogen (N_2), and hydrogen sulphide (H_2S) increased with depth.

In general, near-critical oil, volatile oil, and gas condensate exhibit the largest composition variations with depth, and dry gas and black oil has the lowest variations. Furthermore, fluid composition variations with depth are minimized in fully undersaturated oil reservoirs (Whitson and Belery 1994; Firoozabadi 1999; Luo and Barrufet 2004).

Barrufet and Jaramillo (2004) investigated the effects of compositional grading on OOIP and OGIP estimations for a near-critical reservoir in Cusiana Oilfield. They indicated that the failure to account for compositional grading leads to significant errors in OOIP and OGIP calculations, as their failure in accounting for compositional grading in a volatile oil system resulted in 12% underestimated OOIP and 9.4% overestimated OGIP in the concerned reservoir. Moreover, the failure to account for compositional grading in a gas condensate system led to 54% overestimation of OOIP and 15.6% underestimation of OGIP. They further studied the effects of production well completion on oil recovery in the field, suggesting the maximum oil recovery from the field to be realized when production wells are completed in deeper parts of the reservoir.

Syahrial (1999) studied the natural depletion and miscible gas injection scenarios in a volatile oil reservoir in order to evaluate the compositional grading phenomenon. He found that natural depletion reduced light components of reservoir fluid; however, such components in miscible gas injection tend to be evaporated and move upward, while the intermediate oil components exhibiting some reductions. He further showed that variations of the reservoir pressure and saturation pressure caused by the volatility of reservoir fluid followed nonlinear trends.

Wang et al. (2015) investigated the compositional grading phenomenon in a number of hydrocarbon systems and found that depth-induced variations in black oil and light oil characteristics were much lower than those in volatile oil and near-critical oil types. In the next step, they studied the impact of this phenomenon on oil recovery of a volatile oil reservoir under different scenarios, namely natural depletion, water injection, and gas injection. They concluded that the effect of compositional grading on oil recovery was much greater in the gas injection scenario rather than the other scenarios.

In this paper, a simulation study was conducted to investigate the effects of compositional grading on reservoir fluid properties and the injection of different gases into an Iranian oil reservoir in order to enhance oil recovery and determine the optimum depth of gas injection. For this purpose, three-parameter Soave–Redlich–Kwong (Soave 1972) equation of state was used to match the experimental data using PVTi package. In addition, FloGrid package was used to make the reservoir static model. Then reservoir simulation model was matched with the history data using history matching methods in order to achieve a greater reliability. A one-dimensional slim-tube model was defined using ECLIPSE 300 software to determine the minimum miscibility pressure (MMP) for different injection gases. Finally, different injection scenarios were investigated and optimal injection depth was identified.

Theoretical concept of compositional grading

Gibbs free energy under a gravitational field can be expressed by Firoozabadi (1999) equation, as follows:

$$\mathrm{d}G = -S\mathrm{d}T + V\mathrm{d}P + mg\mathrm{d}Z + \sum_{i=1}^{c}\left(\mu_i + M_i gZ\right)\mathrm{d}n_i \quad (1)$$

where G is Gibbs free energy, S is entropy energy, T is temperature, V is volume, P is pressure, m is mass, g is gravitational constant, Z denotes vertical depth, c is total number of components, μ_i refers to chemical potential of the ith component, M_i is molecular weight of the ith component, n_i denotes the number of moles of the ith component, with i denoting the component number.

Pressure and depth are related to one another via hydrostatic head equation:

$$V\mathrm{d}P + mg\mathrm{d}Z = 0 \quad (2)$$

$$V\mathrm{d}P = -mg\mathrm{d}Z \quad (3)$$

$$\mathrm{d}P = -\rho g\mathrm{d}Z \quad (4)$$

At equilibrium, dG must vanish, since Z and P are dependent, then:

$$\mathrm{d}T = 0$$

$$\mu_i + M_i gZ = 0 \quad i = 1, 2, 3, \ldots, c$$

$$V\mathrm{d}P + mg\mathrm{d}Z = 0 \quad (5)$$

Gibbs sedimentation equation can be derived from the second expression of Eq. (5):

$$\left(\mathrm{d}\mu_i = -M_i g\mathrm{d}Z\right)_T \quad i = 1, 2, 3, \ldots, c \quad (6)$$

Chemical potential of the ith component can be expressed in terms of fugacity, as follows:

$$\left(\mathrm{d}\mu_i = RT\mathrm{d}\ln f_i\right)_T \quad i = 1, 2, 3, \ldots, c \quad (7)$$

Substituting Eqs. (6) and (7) gives:

$$\left(RT\mathrm{d}\ln f_i = -M_i g\mathrm{d}Z\right)_T = 0 \quad i = 1, 2, 3, \ldots, c \quad (8)$$

By integrating Eq. (8) from zero datum depth to depth Z,

$$f_i = f_i^{\circ} \exp\left[-\frac{M_i g}{RT}Z\right] \quad i = 1, 2, 3, \ldots, c \quad (9)$$

where f_i is the fugacity of the ith component in a given phase at the depth Z and f_i^0 denotes the fugacity of the ith component in a given phase at the datum depth.

Therefore, having both the pressure and fluid composition at datum depth, Eq. (9) can be utilized to obtain the fluid pressure and composition at the desired depth.

Reservoir fluid properties

Accurate and correct determination of reservoir fluid properties is one of the most important factors in the study and dynamic modelling of hydrocarbon reservoirs (Sadeghi et al. 2016). In order to model reservoir fluid properties, the available experimental PVT data at datum depth including constant composition expansion (CCE), differential liberation (DL), and separator flash tests were fed into PVTi package. The reservoir fluid composition at datum depth is reported in Table 1. In order to obtain a proper equation of state (EOS) to predict the PVT properties of the reservoir fluid, sensitivity analysis was performed using several equations of state. According to the obtained results, three-parameter Soave–Redlich–Kwong EOS (Soave 1972) was selected for the present study. Furthermore, the fluid viscosity was calculated using Lohrenz et al. (1964) equation. Afterwards,

Table 1 Reservoir fluid composition at datum depth

Component	Mole%
N_2	0.12
CO_2	0.79
C_1	36.74
C_2	6.35
C_3	5.29
iC_4	1.36
nC_4	3.89
iC_5	1.58
nC_5	1.7
C_6	5.22
C_7	4.17
C_8	2.97
C_9	2.55
C_{10}	2.45
C_{11}	2.34
C_{12+}	22.48

selecting proper parameters of the EOS for regressing, a good match was obtained between the experimental data at datum depth and calculated results using the EOS. Reservoir fluid simulation results are shown in Fig. 1.

Reservoir model

The oil reservoir understudy falls within an extended anticline along a north-west—south-east trend as do other structures in south-western Iran. The present research was conducted on a segment of the south-eastern part of the reservoir into which four active wells had been already drilled. The reservoir is a sandstone reservoir with a little amount of lime, and it consists of six layers. The reservoir fluid composition within each layer is reported in Table 2. This is an undersaturated oil reservoir of no gas cap which contains high quality oil of 33° API gravity. Geological observations indicate an aquifer of limited activity surrounding the reservoir. In order to build the static model of the reservoir, FloGrid Package was used (Fath and Pouranfard 2014; Fath et al. 2016). General properties of the reservoir under investigation are reported in Table 3. Furthermore, the three-dimensional static model of reservoir is illustrated in Fig. 2.

Results and discussion

Compositional grading in the reservoir understudy

In order to check for the existence of compositional grading phenomenon in the reservoir understudy, variations in reservoir pressure and saturation pressure and also in molar percentages of reservoir fluid components with depth were investigated.

In this reservoir, the temperature gradient was very low and according to the obtained samples from the fluid at

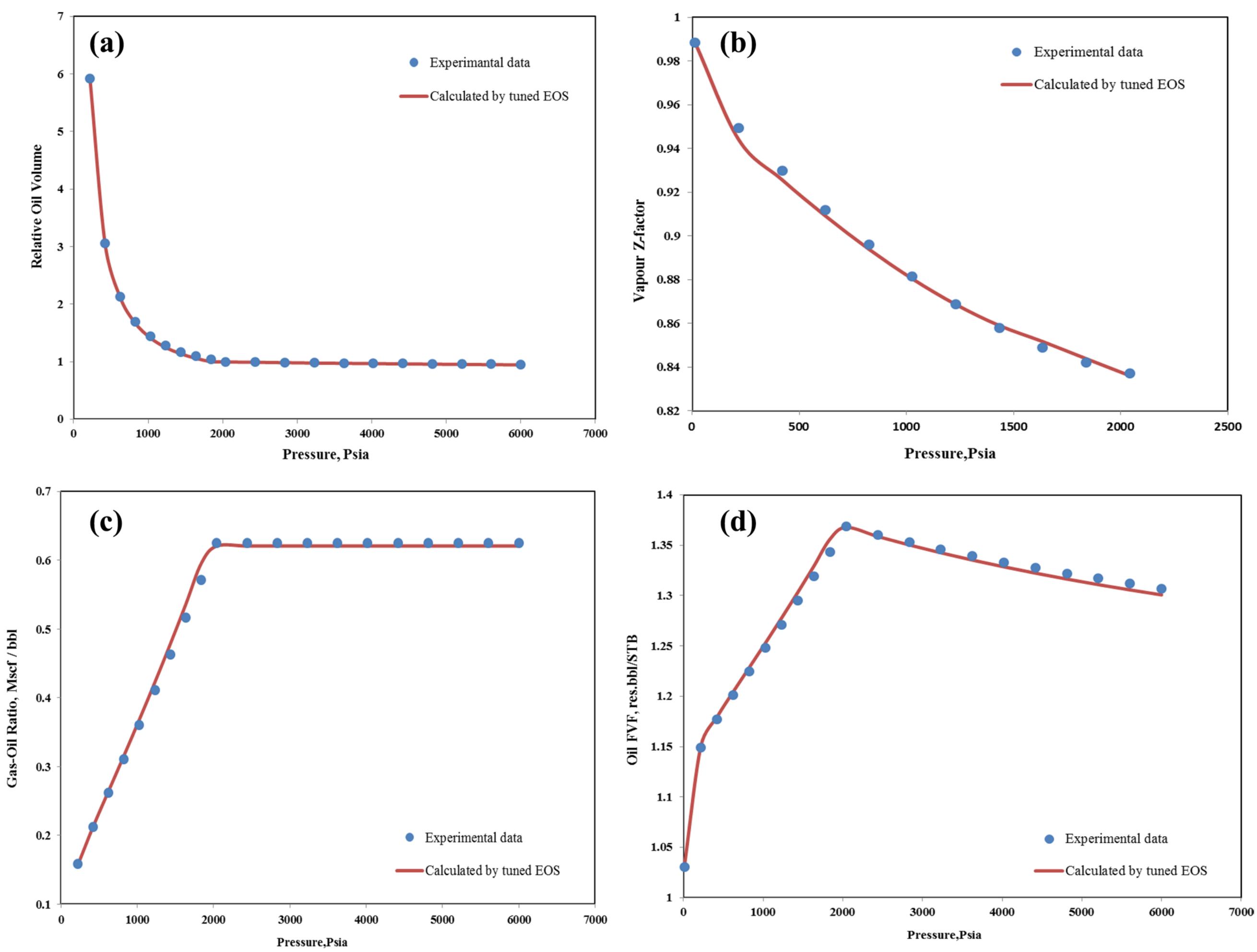


Fig. 1 Comparison of experimental and calculated PVT data, **a** relative volume (CCE test), **b** vapour *z*-factor (DL test), **c** gas/oil ratio (DL test), **d** oil formation volume factor (DL test)

Table 2 Reservoir fluid composition in different layers of the reservoir

Mole%					
Component	Layer#1	Layer#2	Layer#3	Layer#4	Layer#5
N_2	0.1201	0.1199	0.1196	0.1196	0.1192
CO_2	0.7899	0.7901	0.7903	0.7903	0.7907
C_1	36.7909	36.664	36.5379	36.5379	36.2883
C_2	6.3566	6.3401	6.3237	6.3237	6.2909
C_3	5.2949	5.2826	5.2703	5.2703	5.2457
iC_4	1.3612	1.3584	1.3554	1.3554	1.3498
nC_4	3.893	3.8855	3.878	3.878	3.8629
iC_5	1.581	1.5784	1.5758	1.5758	1.5705
nC_5	1.7012	1.6982	1.6953	1.6953	1.6894
C_6	5.2234	5.2149	5.2063	5.2063	5.1889
C_7	4.1708	4.1687	4.1665	4.1665	4.1619
C_8	2.9702	2.9697	2.9693	2.9693	2.9681
C_9	2.5498	2.5503	2.5508	2.5508	2.5516
C_{10}	2.4495	2.4508	2.452	2.452	2.4542
C_{11}	2.3392	2.3411	2.3429	2.3429	2.3463
C_{12+}	22.4083	22.5873	22.7659	22.7659	23.1216

Table 3 General properties of the reservoir

Parameter	Value
Number of grids in *X* direction	24
Number of grids in *Y* direction	17
Number of grids in *Z* direction	6
Dimensions (ft) *X*	500
Dimensions (ft) *Y*	500
Dimensions (ft) *Z*	100
Porosity (%)	14.6
Permeability (md)	10.3
Net to gross (NTG) (%)	0.74
Reservoir datum depth (ft)	9980
Reservoir reference pressure (psi)	5650
Reservoir temperature (°F)	220

different depths, almost no variation in the composition and physical properties of the fluid in the horizontal direction are observed. Figure 3 shows the changes in reservoir pressure and saturation pressure with depth. As shown in this figure, these two parameters change with depth. As depth increases, reservoir fluid becomes heavier leading to increased reservoir pressure and reduced saturation pressure. According to the figure, the reservoir pressure gradient and saturation pressure gradient are about 0.33 psi/ft and 0.11 psi/ft, respectively.

Whitson and Belery (1994) stated that saturation pressure gradient ranges from 0.112 psi/ft for black oil up to a maximum of 4.48 psi/ft for near-critical oils and near a GOC.

Figure 4 demonstrates variations in molar percentage of different components of the reservoir fluid versus depth. According to the figure, the largest variations are those of methane and plus fraction (C_{12+}) which tend to increase and decrease, respectively, with depth. Other reservoir fluid components are almost constant at all depths, confirming the existence of compositional grading phenomenon.

The Effect of compositional grading on the estimation of stock tank original oil in place (STOOIP)

In this section, the importance of compositional grading in the calculation of STOOIP is considered. For this purpose, STOOIP was calculated with and without considering compositional grading. The estimated value for the case with compositional grading is considered as the real value of STOOIP.

In order to investigate the effect of reservoir fluid sampling depth on STOOIP calculation, six depths were considered in six reservoir layers. The corresponding results to each depth are demonstrated in Fig. 5.

According to the figure, when reservoir fluid sampling depth falls within either the layer 1 or layer 2, the obtained STOOIP value tends to be underestimated, while it is to be overestimated in cases where fluid sampling depth falls within each of the layers 4, 5, or 6. However, the estimated STOOIP was found to be very close to the real value when reservoir fluid sampling depth fell within the layer 3. The reduction in heavy components and the increase in oil formation volume factor (OFVF) in the upper parts of the reservoir resulted in an underestimated STOOIP. This is while, in lower parts of the reservoir, increased heavy components along with reduced OFVF resulted in an overestimated STOOIP value.

Therefore, taking reservoir fluid samples from either the upper or lower parts of the reservoir may end up in significant errors with the estimated STOOIP value, while selecting the middle of the reservoir (i.e. layer 3) as the sampling depth of the fluid brings satisfying result for the calculation of the STOOIP value which is well-close to the corresponding real value. Thus, even with disregarding the compositional grading, one can solely focus on reservoir fluid sampling depth (i.e. to choose the best depth to take reservoir fluid sample from, which is the reservoir middle depth) to achieve an accurate estimation of the reservoir STOOIP.

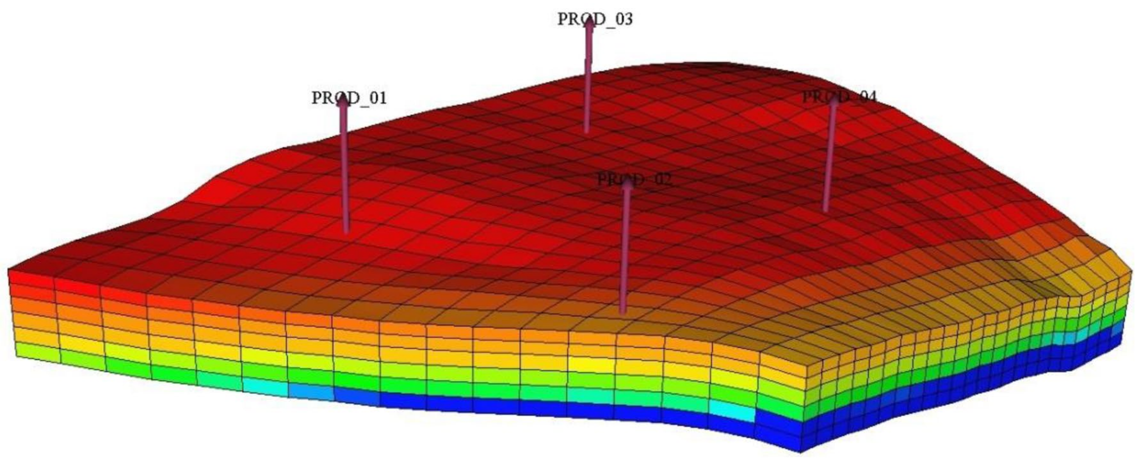
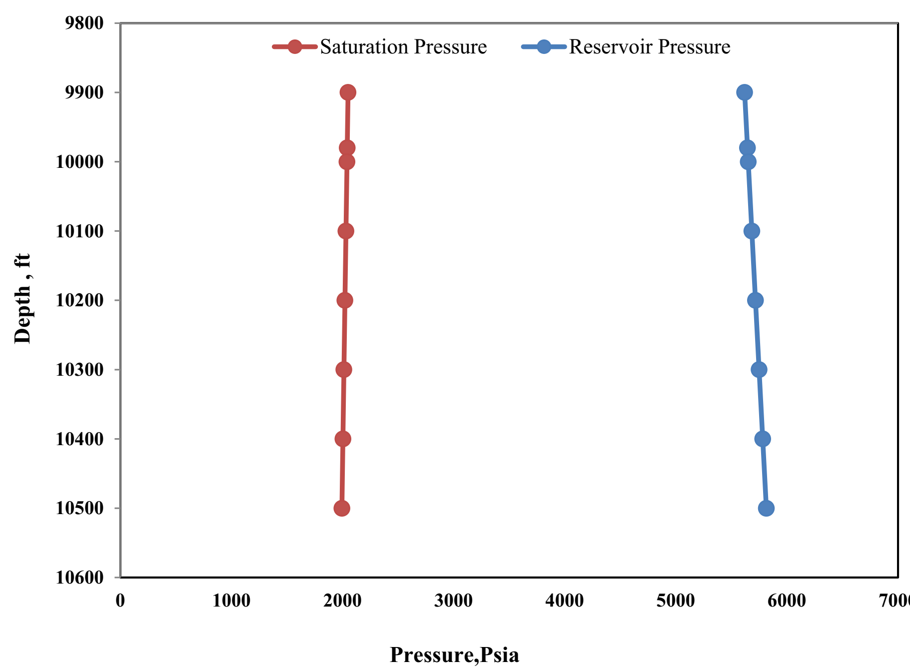


Fig. 2 Three-dimensional model of the reservoir

Fig. 3 Reservoir pressure and saturation pressure variations with depth



Reservoir performance forecast

In this part of the study, the aim was to investigate the effect of compositional grading phenomenon on gas injection process into the reservoir to enhance oil recovery. For this purpose, the injection of various gases including CO_2, N_2, APG, N_2–CO_2 mixture and water-alternating-CO_2 injection into different reservoir layers was studied.

In order to have a proper comparison, different scenarios need to be evaluated under similar operational conditions in terms of layers in which production and injection wells are completed, and well location as well as injection and production rates. To this end, an injection well was created among the production wells and all the injection scenarios were run for 39 years (2015–2054). In all simulations, gas injection rate was set to 18 MMSCFD, bottom-hole injection pressure was set to 5500 psi, and oil production rate was set to 2000 STBD for each producing well. Furthermore, the following economic limitations were considered for shutting the production wells:

Maximum GOR: 1800 SCF/STB
Maximum water cut: 40%
Minimum oil production rate: 150 STBD

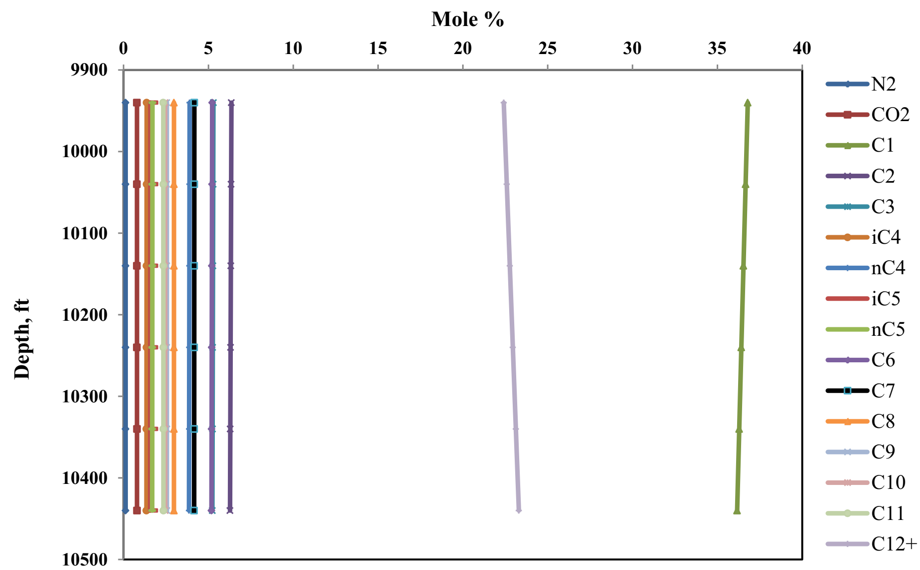


Fig. 4 Variations in molar percentages of reservoir fluid components with depth

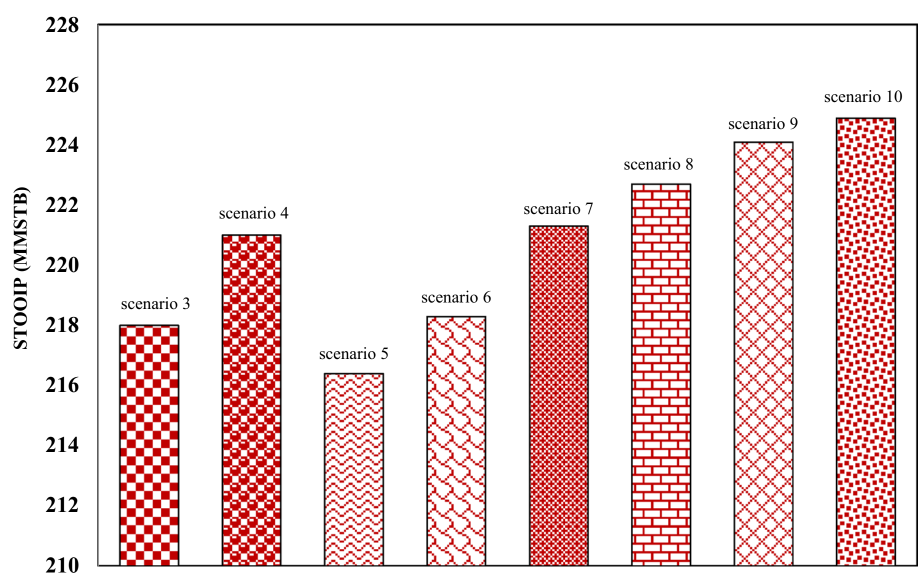


Fig. 5 Calculation of STOOIP considering the composition of fluids in different layers of the reservoir

Before running different injection scenarios, history matching process should be done in order to ensure the reliability and validity of the simulated model. In this process, the common approach to match the model is to change the parameters with the highest effects, including permeability, porosity, block height, and aquifer parameters (Fath and Pouranfard 2014; Fath and Dashtaki 2016). In this study, the history matching was performed on production rate and reservoir pressure data within a 14-year period (2000–2014). Figures 6 and 7 show the oil production rate of production wells and field pressure, respectively. The figures indicate a good match between the calculated results and historical data. Average reservoir pressure was 4400 psi in the late 2014.

Moreover, natural depletion scenario was investigated at the datum depth with and without considering compositional grading in order to have a base for comparison. As shown in Fig. 8, higher oil recovery percentage was obtained when compositional grading was taken into consideration.

The effect of compositional grading on minimum miscibility pressure (MMP)

In a compositionally grading oil reservoir, due to variations in reservoir fluid properties with depth, one would observe the respective variations in MMP.

MMP refers to the minimum pressure at which the displacement process is performed miscibly. In other words,

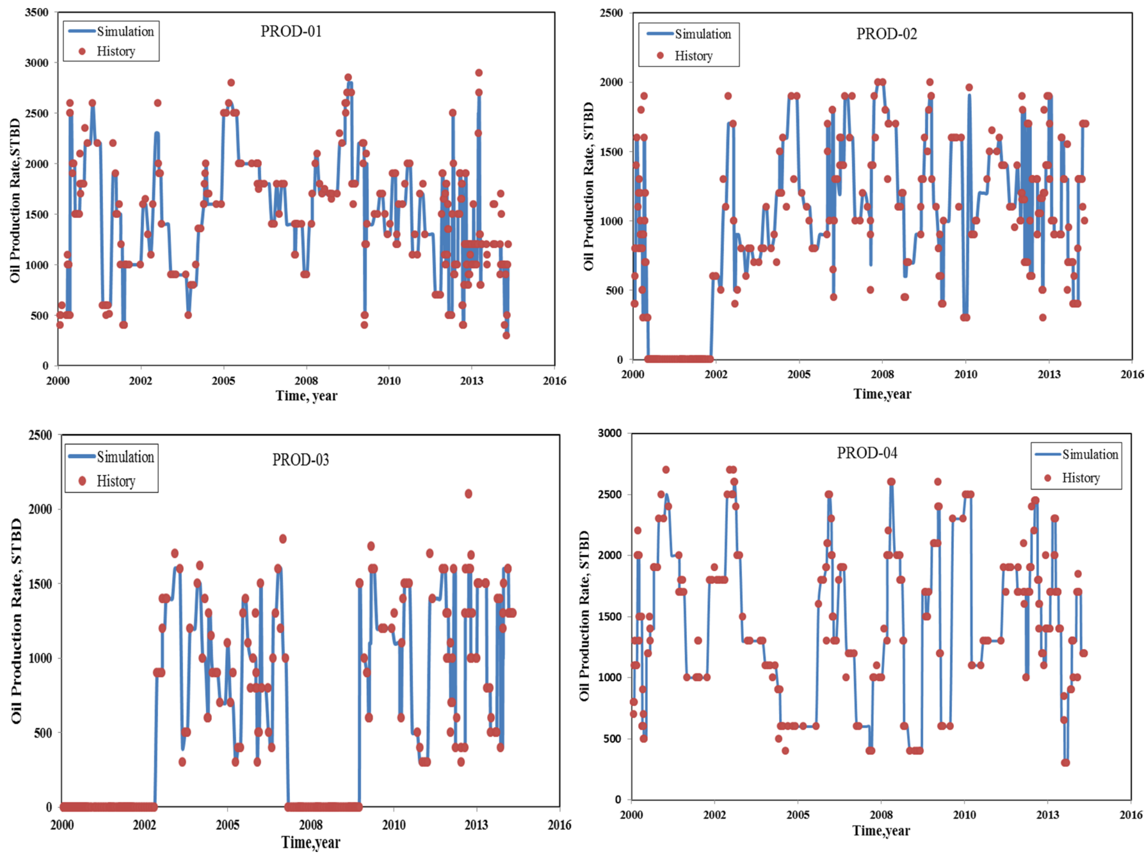
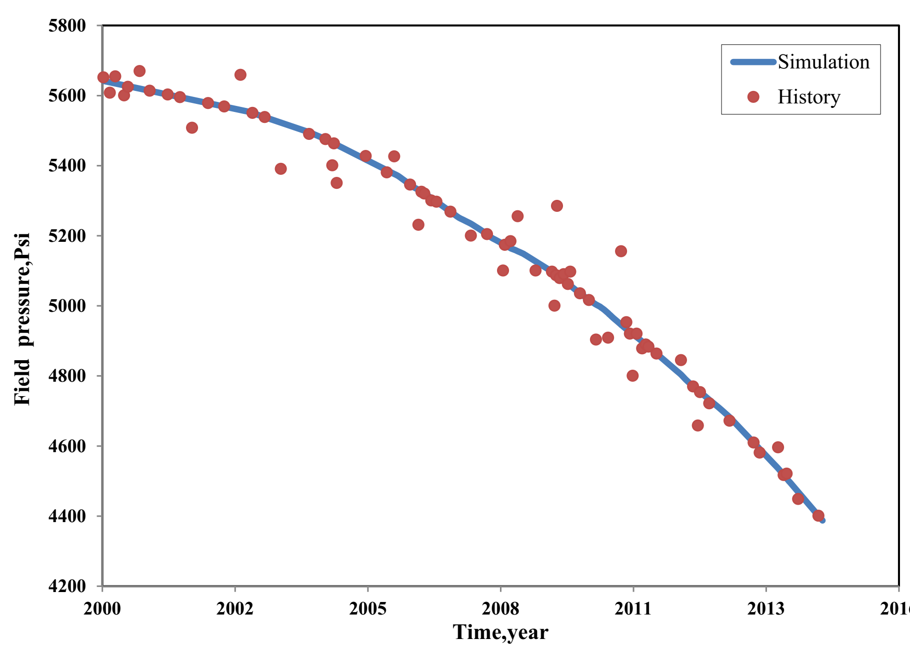


Fig. 6 History matching results of oil production rate of different wells

Fig. 7 History matching results of field pressure



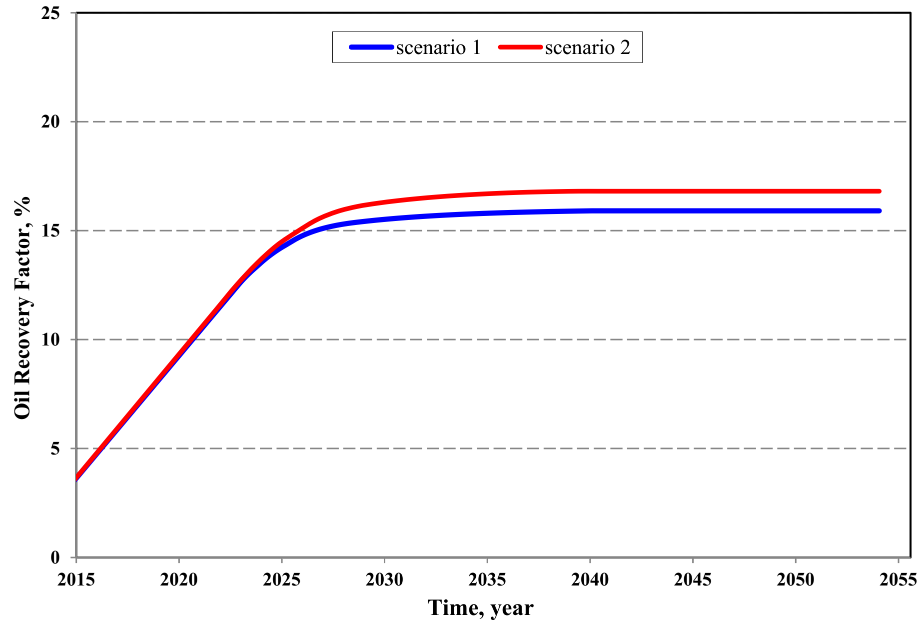


Fig. 8 Oil recovery factor under natural depletion with and without compositional grading

MMP defines the pressure at which displacement efficiency approaches 100%.

At lower parts of the reservoir, due to heavier reservoir fluid and increased reservoir pressure, MMP value is increased and miscibility development is carried out very slow. In many cases, the gas immiscibly displaces oil in this part of the reservoir; however, the existence of light components in reservoir fluid at upper parts of the oil column reduces the value of MMP, resulting in better miscibility and increased sweep efficiency.

Establishing miscibility conditions in the reservoir can improve the reservoir oil displacement through reducing interfacial tension (IFT) between gas and oil, capillary forces, and gas override.

In the present study, a one-dimensional slim-tube model was simulated to determine MMP of different injected gases with reservoir fluid in different reservoir layers. Table 4 reports MMP variations with reservoir depth for injection of different gases into the reservoir.

The effect of compositional grading on different injection gases

The performance of the different injection gases with and without compositional grading are reported in "Appendix". As can be seen in Table 6, when the reservoir oil composition was supposed to be constant through the entire hydrocarbon column, 2.303%, 2.074%, 3.489%, 3.198%, and 1.66% decrease was noticed in the ultimate oil recovery factor of CO_2, N_2, APG, 50% N_2–50% CO_2, and water-alternating-CO_2 injection scenarios, respectively. This confirms that the ignorance of compositional grading phenomenon results in a decrease in the estimated ultimate oil recovery.

CO_2 injection

CO_2 is one of the most important greenhouse gases whose emission into the atmosphere contributing to environmental pollution and global warming. Nowadays, one of the best and most effective approaches to inhibit CO_2 emission into the environment is to have it gathered and stored into

Table 4 MMP variations with reservoir depth for injection of different gases into the reservoir

Scenario	MMP, Psi					
	Layer#1	Layer#2	Layer#3	Layer#4	Layer#5	Layer#6
CO_2 inj.	3572	3591	3641	3674	3708	3729
N_2 inj.	6943	6985	7035	7067	7086	7116
APG inj.	6751	6768	6797	6832	6853	6879
50% N_2–50% CO_2 inj.	6108	6137	6176	6258	6283	6331
Water-alternating-CO_2 inj.	–	–	–	–	–	–

hydrocarbon reservoirs in order to maintain reservoir pressure and hence increasing oil recovery.

Major sources of CO_2 emission are power plants, oil and gas refineries, and other industries which end up producing this gas as a by-product of their processes. Among these sources, the power plants which use fossil fuels to generate electrical power are deemed to be the most significant CO_2 emitters.

Being close to a power plant, the reservoir was in a suitable condition for collecting the produced CO_2 from the power plant and having the collected gas injected into the reservoir not only to prevent the CO_2 from being emitted, but also to enhance oil recovery factor.

As is specified in Table 4, all MMP values calculated in the course of CO_2 injection were lower than reservoir pressure (i.e. 4400 psi when injecting different gases into the reservoir); therefore, CO_2 injection will be miscible at all layers of this reservoir. In the miscible gas injection process, the gravity segregation of the gas is not possible; hence, the gas override is minimized and sweep efficiency is improved, As a result, oil recovery factor is increased.

Figure 9 demonstrates oil recovery factor for CO_2 injection into the reservoir under different scenarios. As it can be seen in this figure, almost similar oil recovery factor is obtained for all CO_2 injection scenarios, and little differences are noticed among different scenarios.

Increased oil recovery factor in upper parts of reservoir layers, compared to the lower layers, is because of the later achievement of injection bottom-hole pressure and the possibility of allowing more gas to be injected into these layers. According to Table 6 in "Appendix", the difference between cumulative injected gas after 39 years of CO_2 injection under scenarios 21 and 26 was 6.5 MMMSCF which gives rise to an approximately 2 months extended production plateau under scenario 21 (Fig. 10). This increase in the production plateau resulted in the corresponding oil recovery factor to improve by 1.004% under scenario 21. Due to more CO_2 injection, the reservoir pressure drop in upper layers of reservoir was lower, contributing to the maintained reservoir pressure.

N_2 injection

N_2 is one of the most abundant, the least expensive and the most available non-hydrocarbon gases to be injected into a reservoir. N_2 is an inert gas virtually with no reaction to oil and may introduce no impurity into the reservoir oil (Christensen et al. 1998). The required N_2 for enhanced oil recovery (EOR) can be either taken from air, flue gas or gas reservoirs of high N_2 content.

MMP calculation results for N_2 injection indicates that this gas is an immiscible gas in all reservoir layers (Table 4). In general, MMP of N_2 with the reservoir oil is usually too high, so that, it is not possible to achieve such a high pressure and establish miscibility conditions within the reservoir. Therefore, N_2 injection into oil reservoirs often follows an immiscible process. In fact, the immiscible process causes the gas override and faster movement of the gas than the reservoir oil which leads to a large volume of oil reservoir, especially in lower parts of the reservoir is not swept, and ultimately reduced oil recovery.

Figure 11 shows oil recovery factor for N_2 injection into different reservoir layers. As it is shown, the difference between the plots of oil recovery in N_2 injection is greater when compared to CO_2 injection. Furthermore, the completion of the injection well in layer 1 exhibits different

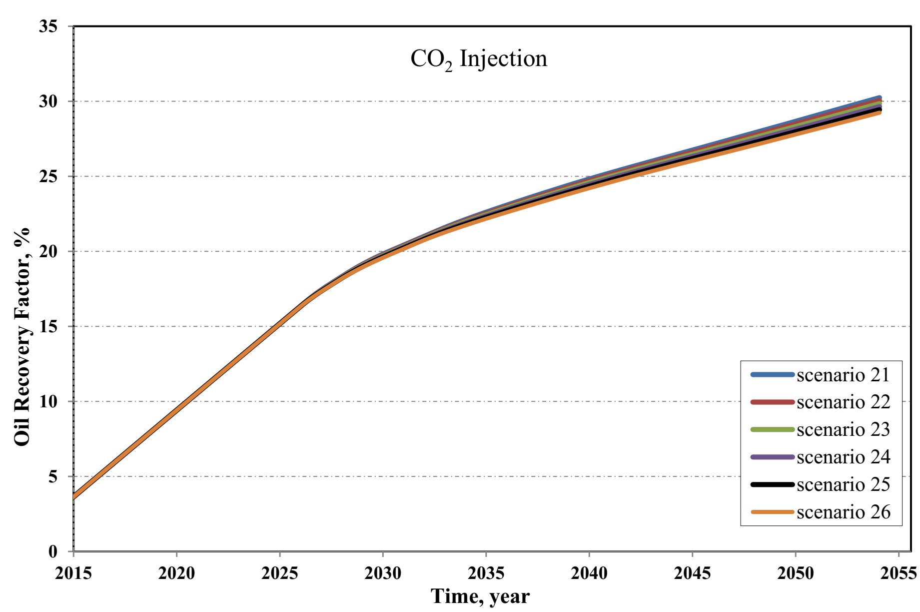


Fig. 9 Oil recovery factor for CO_2 injection into different reservoir layers

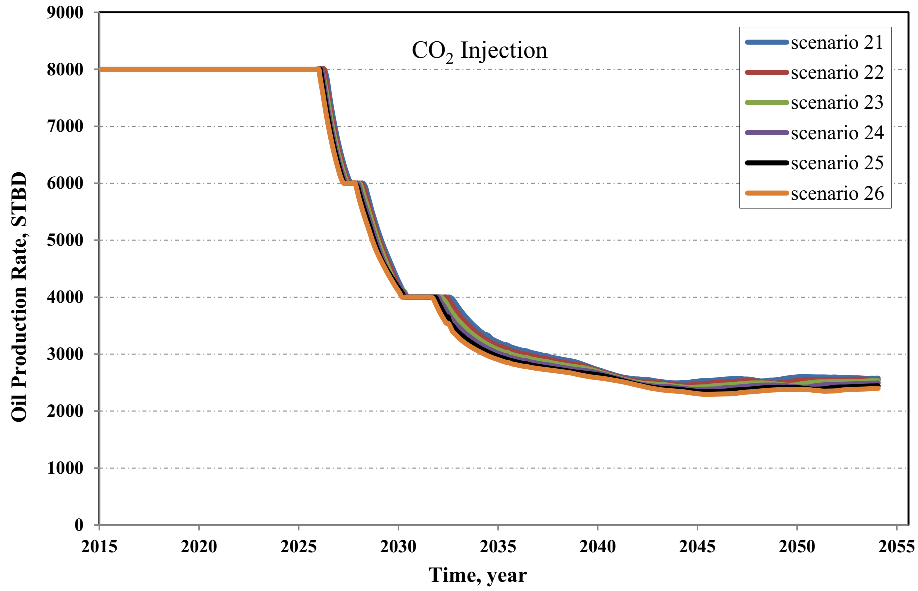


Fig. 10 Reservoir oil production rate for CO_2 injection into different reservoir layers

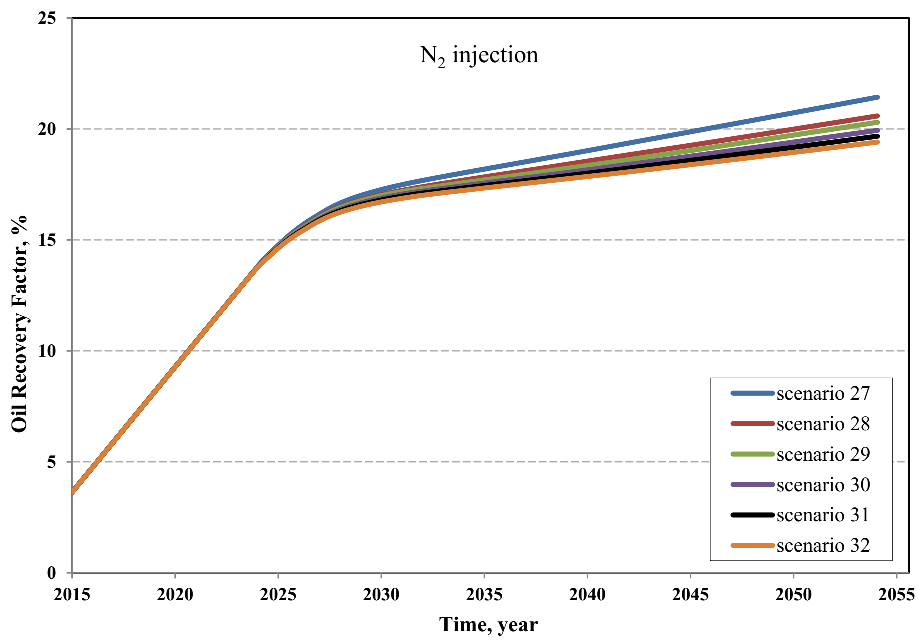


Fig. 11 Oil recovery factor for N_2 injection into different reservoir layers

performance and higher recovery factor compared to other N_2 injection scenarios due to the injection of larger volumes of gas into this layer. Injecting larger volumes of N_2 in the first layer extends the production plateau for 9 months as compared to its injection into the lowest layer (Fig. 12).

The difference between corresponding ultimate oil recovery factors to N_2 injection when the injection well is completed in the highest and lowest reservoir layers was found to be 2.022%, which is a higher difference than that in CO_2 injection scenarios.

Injecting N_2 into upper layers of reservoir contributes to better reservoir pressure maintenance, so that the difference between scenarios 27 and 32 is 125 psi ("Appendix"). The simulation results of N_2 injection indicate that N_2 injection is associated with better performance in terms of maintaining reservoir pressure in comparison with the miscible injection of CO_2, although it has lower oil recovery.

Associated petroleum gas (APG) injection

APG is obtained during the produced crude oil processing at surface. (It can be seen as either oil-dissolved or a separated associate phase with oil.) APG is mainly composed of light hydrocarbons compounds, particularly methane. In addition

Fig. 12 Reservoir oil production rate for N_2 injection into different reservoir layers

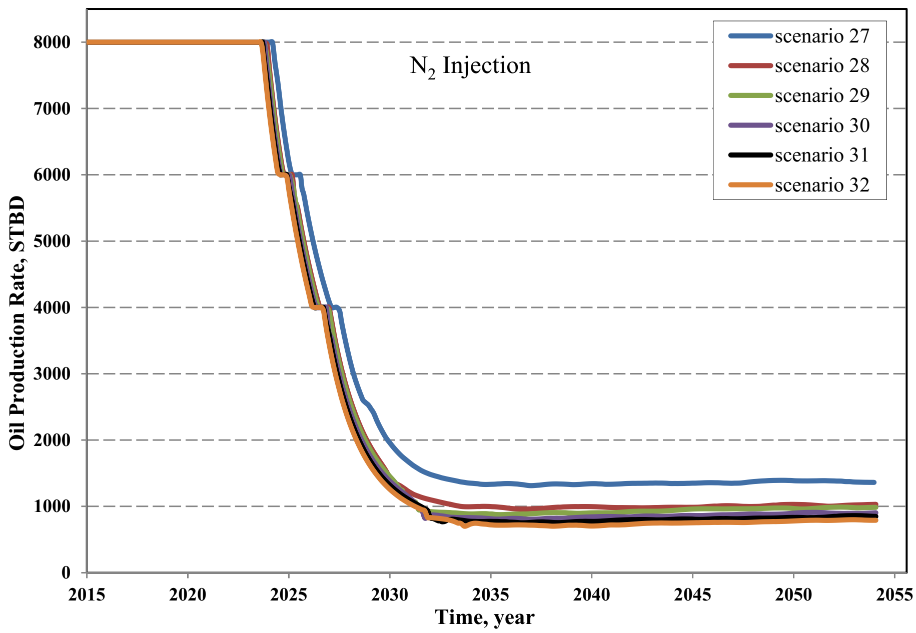


Table 5 Composition of the injected APG into the reservoir

Component	Mole%
N_2	0.19
CO_2	1.4
C_1	66.18
C_2	11.15
C_3	8.61
iC_4	1.76
nC_4	4.52
iC_5	1.54
nC_5	1.65
C_6	1.61
C_7	0.98
C_8	0.39
C_9	0.02
C_{10}	0
C_{11}	0
C_{12+}	0

to its hydrocarbon components, it sometimes contains such impurities as N_2, CO_2, and H_2S. The most significant advantage of APG injection into oil reservoirs is due to its availability at the site of injection and its reduced transfer costs. In addition to crude oil processing, outflows from gas condensate and wet gas wells can also be processed to obtain similar compounds of APG. The composition of the injected APG into the reservoir is reported in Table 5.

As can be seen in Table 4, the MMPs corresponding to APG injection in all layers are larger than reservoir pressure, indicating immiscible nature of all APG injection scenarios. The high MMP of APG is caused by the high molar percentage of methane in its composition.

Even though miscibility conditions can be developed by injecting excessive APG and evaporating light oil components before being introduced into the injected gas composition (vaporizing gas drive), it is a time-intensive process and a major fraction of the injected APG into the reservoir would form a separated phase from the reservoir oil; therefore, the process can be regarded as immiscible.

According to Fig. 13, the difference between corresponding ultimate oil recovery factors of the injection wells completed in the highest and lowest reservoir layers was found to be 1.992%, resulting in more oil production under scenario 33 in comparison with scenario 38.

Due to immiscible nature of APG injection process and the happening of gas override, microscopic efficiency decreases in the course of the injection process and hence increasing residual oil saturation, particularly in the lower parts of the reservoir and finally reducing oil recovery factor.

According to Fig. 14, production plateau is relatively increased in APG injection, as compared to that in the case of N_2 injection. It is, however, still much lower compared

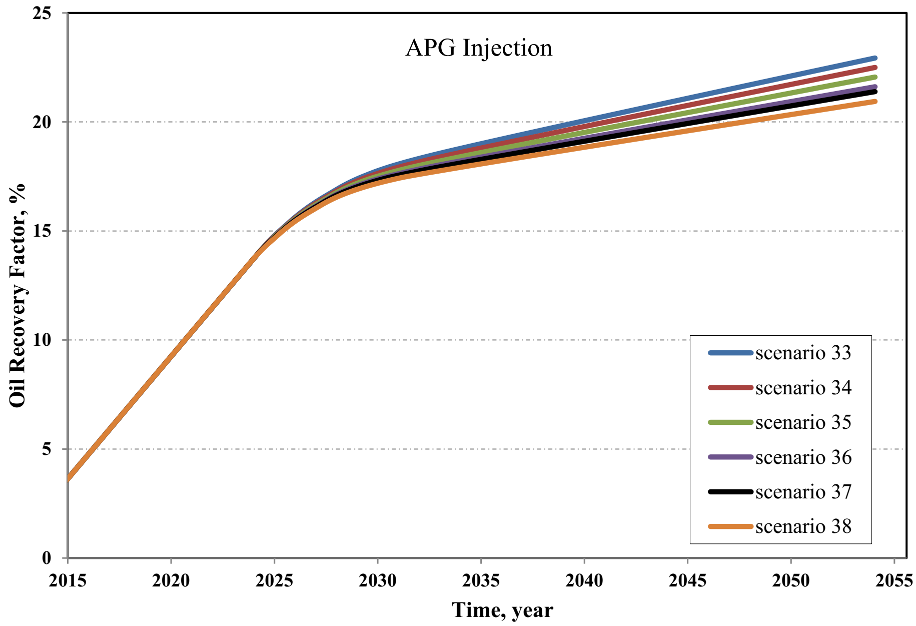


Fig. 13 Oil recovery factor for APG injection into different reservoir layers

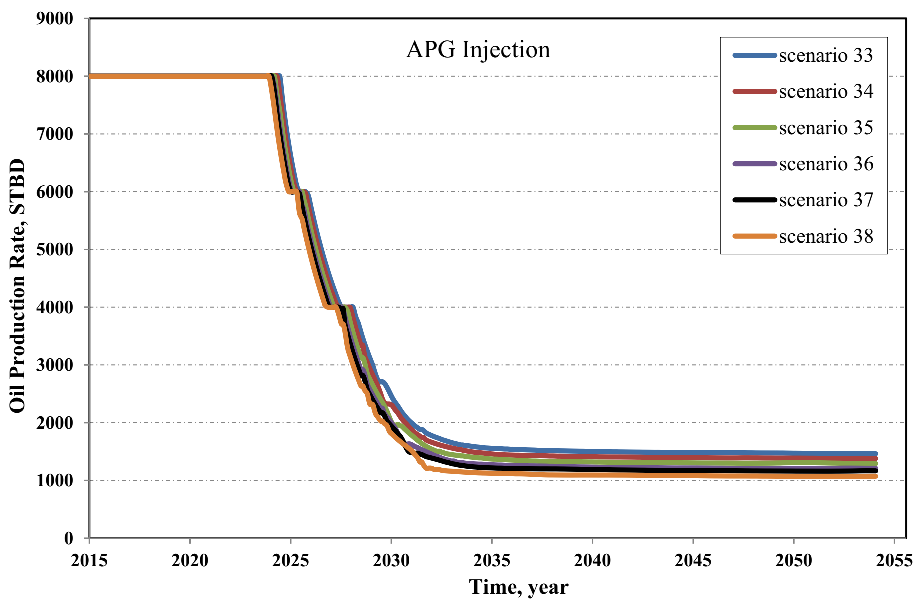


Fig. 14 Reservoir oil production rate for APG injection into different reservoir layers

to the production plateau in the miscible CO_2 injection. Moreover, APG injection reveals a weaker performance in comparison with N_2 injection in terms of reservoir pressure maintenance.

N_2 diluted by CO_2 injection

As previously mentioned, the MMP of N_2 gas is very high, and in most cases, it is immiscibly injected into reservoir.

Because of the low density of N_2 relative to the reservoir oil and the immiscible conditions of N_2 injection, the gas override and channelling phenomena would occur, leading to the early production of N_2 from the production wells (breakthrough). Consequently, a large volume of oil within the lower parts of the reservoir would not be swept, and the sweep efficiency would be reduced. To sum up, oil recovery in N_2 injection scenario is lower than the other scenarios.

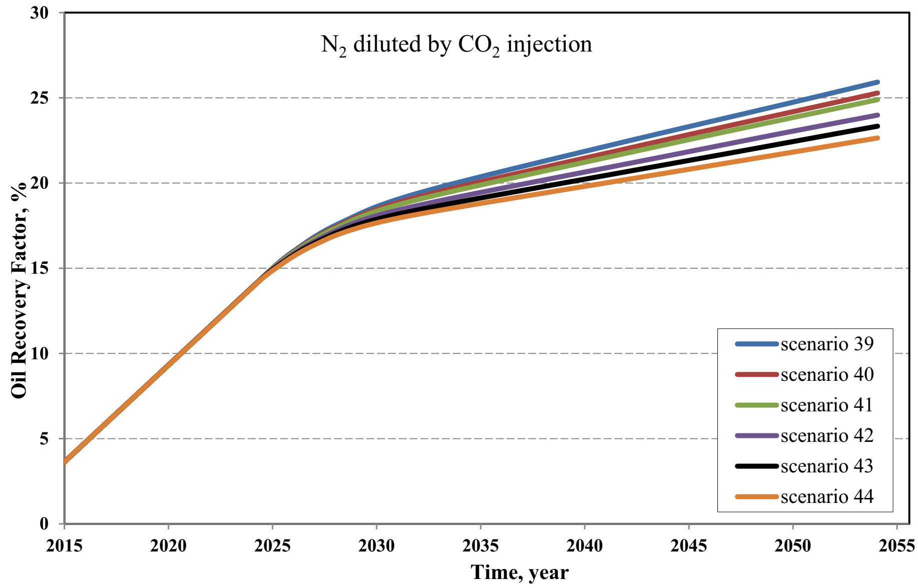


Fig. 15 Oil recovery factor for 50% N_2–50% CO_2 mixture into different reservoir layers

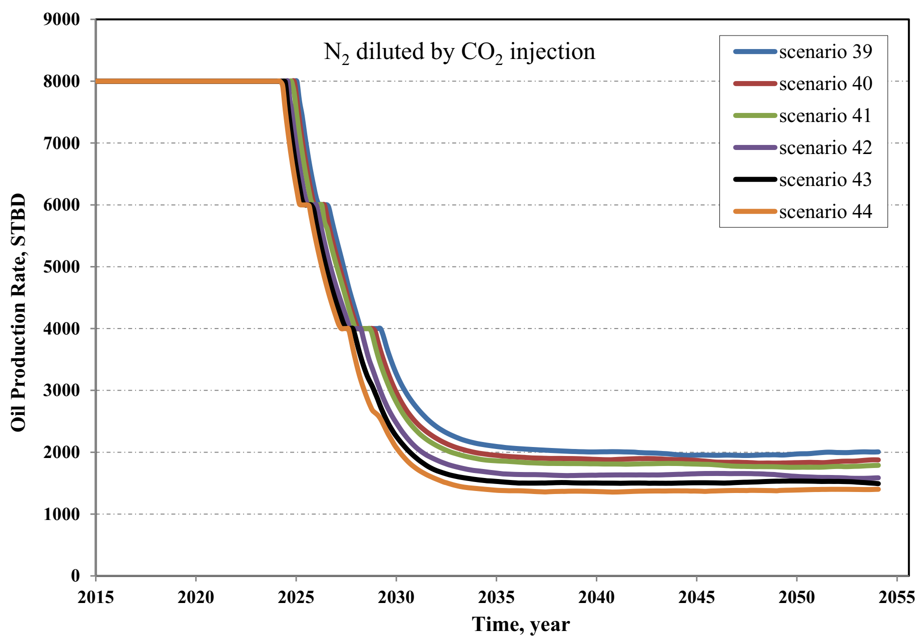


Fig. 16 Reservoir oil production rate for 50% N_2–50% CO_2 mixture into different reservoir layers

In order to enhance oil recovery and reduce MMP of N_2 injection, the gas was diluted by CO_2 and N_2–CO_2 mixture (50% N_2–50% CO_2) was provided to be injected into different reservoir layers. Adding CO_2 to pure N_2 reduced its MMP and hence provided better conditions in terms of oil recovery (Shahrabadi et al. 2012; Belhaj et al. 2013).

According to Table 4, the addition of CO_2 to N_2 significantly reduces MMP in comparison with the scenarios in which pure N_2 was injected into different reservoir layers, so that the difference between MMP values of pure N_2 and 50% N_2–50% CO_2 mixture was found to be 835 psi when the injection well was completed in layer 1. Although MMP was reduced by adding CO_2 to pure N_2, the calculated MMP

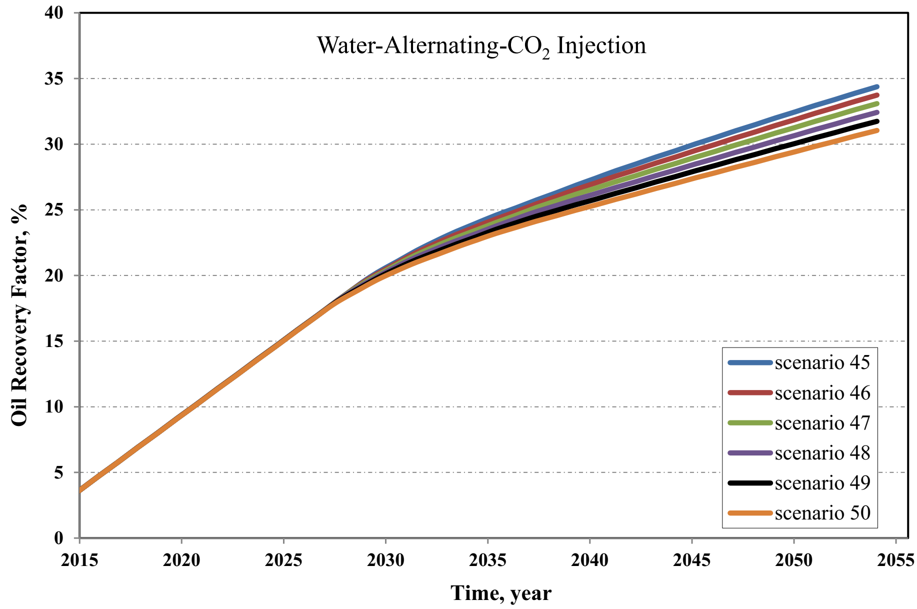


Fig. 17 Oil recovery factor for water-alternating-CO_2 injection into different reservoir layers

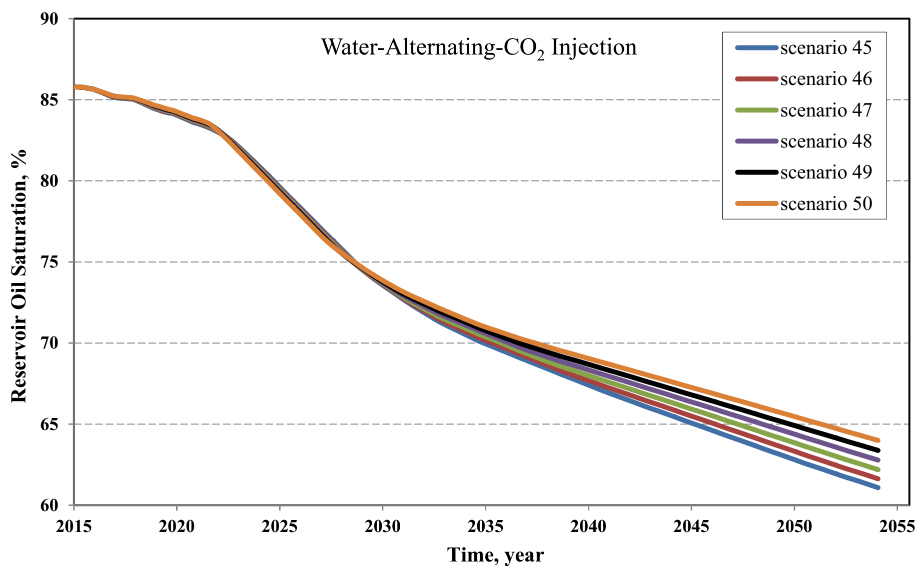


Fig. 18 Reservoir oil saturation variations for water-alternating-CO_2 injection into different reservoir layers

values for 50% N_2–50% CO_2 mixture and oil in different reservoir layers are still high and miscibility conditions may not be established within the reservoir.

According to Fig. 15, it can be observed that, the corresponding recovery factors for 50% N_2–50% CO_2 mixture injection scenarios were higher than those for pure N_2 and APG injection, but still lower than those for CO_2 miscible injection.

The presence of CO_2 in 50% N_2–50% CO_2 mixture allows more gas to be injected into the reservoir compared to the pure N_2 injection (Table 6 in "Appendix"), resulting in greater oil recovery.

Compared to similar case with pure N_2 injection, 50% N_2–50% CO_2 mixture injection into layer 1 was associated

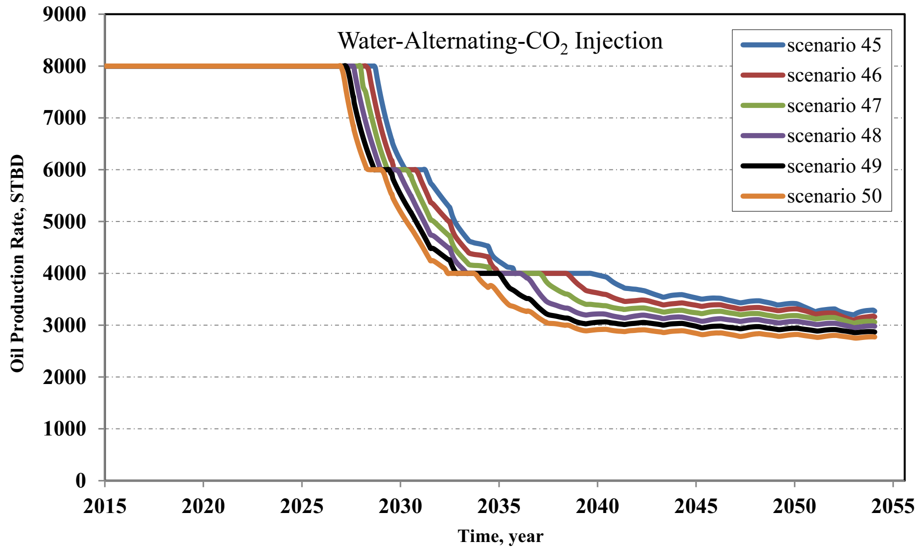


Fig. 19 Reservoir oil production rate for water-alternating-CO_2 injection into different reservoir layers

with 10 months extended production plateau, leading to increased cumulative produced oil by 2.4 MMSTB (Fig. 16); however, pure N_2 injection exhibited better performance in terms of reservoir pressure maintenance.

Water-alternating-CO_2 injection

Density differences between the injected fluid and reservoir oil gives rise to the gravity segregation of these fluids in the reservoir and reduces sweep efficiency. Gravity segregation consequently leads to the migration of the injected gas into upper parts of the reservoir and develops gas override phenomenon. In water injection, it forces the injected water to move into the lower parts of the reservoir and results in the occurrence of water underride phenomenon. In override and underride phenomena, the oil in the lower parts and the upper parts of the reservoir would not be swept.

Both override and underride phenomena are associated with the reduced vertical sweep efficiency and ultimately reduce the total sweep efficiency. Therefore, in order to enhance total sweep efficiency and eventually enhance oil recovery in different EOR processes, the mobility ratio between injected fluid and reservoir oil should always be controlled.

For instance, in water injection process, one of the methods to control the mobility between the injected water and the reservoir oil as well as piston-like movement of the injected water is the use of the polymer (Sorbie 1991; Hodaie and Bagci 1993). In gas injection process, one of the most effective techniques to enhance sweep efficiency and inhibit gas override is water alternating gas (WAG) injection (Caudle and Dyes 1958).

The WAG can enhance sweep efficiency of the injected gas and eventually enhance oil recovery through extending the contact area of the injected gas with the reservoir, controlling the mobility ratio between the injected gas and the reservoir oil, providing effective access to no swept areas for the gas and establishing a stable movement front (Sanchez 1999). In this section of the present research, water-alternating-CO_2 injection was employed to improve macroscopic sweep efficiency and recovery factor in the course of CO_2 miscible injection.

In most of WAG injection processes, the optimum amount of water-to-gas injection ratio is set to one. In this scenario, water-to-CO_2 injection ratio was set to 1 for injecting into all reservoir layers, and water and CO_2 were alternatively injected into different depths. Figure 17 shows the recovery factor under water-alternating-CO_2 injection process into different reservoir layers. As can be seen from this figure, water-alternating-CO_2 injection scenarios provide higher recovery factors compared to the other scenarios. This enhanced recovery can be explained by improved microscopic and macroscopic sweep efficiencies caused by injecting CO_2 and water, respectively. This resulted in enhancing total sweep efficiency and displacing large volumes of reservoir oil.

According to Fig. 17, there are still differences between recovery factors in different injection scenarios, according to which the difference between the recovery factors when water-alternating-CO_2 was injected into the first and the last reservoir layers was found to be 3.332%, confirming the significance of compositional grading in designing the process of water-alternating-CO_2 injection into the reservoir. Furthermore, higher recovery factor due to water-alternating-CO_2 injection into upper layers of reservoir results in reduced residual oil saturation within these layers (Fig. 18).

Further water-alternating-CO_2 injection into upper layers of reservoir may also extend production plateau, so that the production plateau of water-alternating-CO_2 injection into the first layer was 21 months longer than the case where it was injected into the lowest reservoir layer (Fig. 19).

With comparing recovery factors under two scenarios, namely water-alternating-CO_2 injection process and CO_2 miscible injection, when the injection well is completed within the first layer, a difference of 4.136% can be noticed which can be attributed to the poor performance of CO_2 injection in terms of enhancing macroscopic sweep efficiency.

Conclusions

The main conclusions of the present study are as follows:

1. Variations in the reservoir fluid properties under the study such as the molar percentage of its components, reservoir, and saturation pressures with depth not only confirms the existence of compositional grading phenomenon but also indicates that the ignorance of this phenomenon leads to an error in the reservoir and production engineering calculations.
2. Compositional grading plays an important role in STOOIP estimation for reservoirs with variations in fluid composition caused by depth. Thus the failure to account for compositional grading may result in underestimated or overestimated STOOIP value. In such reservoirs, selecting the middle reservoir depth as the fluid sampling depth, one can calculate the STOOIP with a greater accuracy.
3. Failure to account for compositional grading in gas injection processes into reservoir gives rise to differences in oil recovery, underestimating the obtained oil recovery.
4. Due to their high MMP values, N_2 and APG were immiscibly injected into all layers of the reservoir. Although in upper layers of reservoir obtained oil recovery was slightly greater due to the possibility of injecting larger volumes of these gases, the gas override and channelling phenomena led to faster introduction of N_2 and APG gases into the production wells, leading to a significant reduction in oil displacement efficiency. Injecting N_2-CO_2 mixture reduced MMP and increased the volume of injected gas into all reservoir layers, subsequently leading to enhanced oil recovery, compared to pure N_2 injection scenario.
5. CO_2 injection was miscible in all reservoir layers; however, due to the reduced MMP, the miscibility was better and developed faster in upper layers of reservoir. It can be thus concluded that, by completing the injection wells in the upper parts of the reservoir, higher oil recovery is achieved. Compared to N_2, APG, and CO_2–N_2 mixture injections, the miscible CO_2 injection results in enhanced reservoir oil displacement through reducing oil viscosity, IFT, and gravity segregation of injected gas.
6. In order to extend the contact area of CO_2, control its mobility, and enhance macroscopic sweep efficiency, water-alternating-FCO_2 injection was used for all reservoir layers. The results indicated that, water-alternating-CO_2 injection was associated with increased oil recovery, extended production plateau, decreased residual oil saturation, and improved reservoir pressure maintenance in all reservoir layers. This can be explained by simultaneous improvements in macroscopic and microscopic sweep efficiencies which together enhance the total sweep efficiency and thus allow for the production of larger volumes of reservoir oil. Compared to the other injection scenarios, water-alternating-CO_2 injection exhibited higher recovery factor in all reservoir layers; however, more satisfying results were achieved in higher reservoir layers because of the compositional grading phenomenon.

Appendix

See Table 6.

Table 6 Performance of the different injection gases with and without compositional grading in the reservoir understudy

Scenario	Oil composition	Injected fluid	Completion location of injection well	Completion location of production wells	Average reservoir pressure, Psi	Ultimate oil recovery factor, %	Cumulative gas injected, MMMSCF
1	Natural depletion—without compositional grading—using reference composition	–	–	Layers 1–6	1612	15.911	–
2	Natural depletion—with compositional grading	–	–	Layers 1–6	1697	16.811	–
3	Without compositional grading—using reference composition	–	–	–	–	–	–
4	With compositional grading	–	–	–	–	–	–
5	Without compositional grading—using first-layer composition	–	–	–	–	–	–
6	Without compositional grading—using second-layer composition	–	–	–	–	–	–
7	Without compositional grading—using third-layer composition	–	–	–	–	–	–
8	Without compositional grading—using fourth-layer composition	–	–	–	–	–	–
9	Without compositional grading—using fifth-layer composition	–	–	–	–	–	–
10	Without compositional grading—using sixth-layer composition	–	–	–	–	–	–
11	Without compositional grading—using reference composition	CO_2	Layer 4	Layers 1–6	1910	27.341	258.8
12	With compositional grading	CO_2	Layer 4	Layers 1–6	2016	29.644	260.4
13	Without compositional grading—using reference composition	N_2	Layer 4	Layers 1–6	2256	17.865	247.6
14	With compositional grading	N_2	Layer 4	Layers 1–6	2625	19.939	250.8

Table 6 (continued)

Scenario	Oil composition	Injected fluid	Completion location of injection well	Completion location of production wells	Average reservoir pressure, Psi	Ultimate oil recovery factor, %	Cumulative gas injected, MMMSCF
15	Without compositional grading—using reference composition	APG	Layer 4	Layers 1–6	2018	18.125	251.9
16	With compositional grading	APG	Layer 4	Layers 1–6	2383	21.614	253.1
17	Without compositional grading—using reference composition	50% N_2–50% CO_2	Layer 4	Layers 1–6	2211	20.785	255.8
18	With compositional grading	50% N_2–50% CO_2	Layer 4	Layers 1–6	2302	23.983	257.3
19	Without compositional grading—using reference composition	Water-alternating-CO_2	Layer 4	Layers 1–6	2887	30.763	133.1
20	With compositional grading	Water-alternating-CO_2	Layer 4	Layers 1–6	3131	32.423	135.1
21	With compositional grading	CO_2	Layer 1	Layers 1–6	2035	30.241	264.6
22	With compositional grading	CO_2	Layer 2	Layers 1–6	2029	30.045	263.2
23	With compositional grading	CO_2	Layer 3	Layers 1–6	2021	29.845	262.5
24	With compositional grading	CO_2	Layer 4	Layers 1–6	2016	29.644	260.4
25	With compositional grading	CO_2	Layer 5	Layers 1–6	2009	29.441	259.7
26	With compositional grading	CO_2	Layer 6	Layers 1–6	2002	29.237	258.1
27	With compositional grading	N_2	Layer 1	Layers 1–6	2685	21.432	255.4
28	With compositional grading	N_2	Layer 2	Layers 1–6	2644	20.588	254.7
29	With compositional grading	N_2	Layer 3	Layers 1–6	2637	20.300	252.3
30	With compositional grading	N_2	Layer 4	Layers 1–6	2625	19.939	250.8
31	With compositional grading	N_2	Layer 5	Layers 1–6	2612	19.675	248.6
32	With compositional grading	N_2	Layer 6	Layers 1–6	2560	19.410	247.9
33	With compositional grading	APG	Layer 1	Layers 1–6	2421	22.932	257.2
34	With compositional grading	APG	Layer 2	Layers 1–6	2412	22.498	256.7
35	With compositional grading	APG	Layer 3	Layers 1–6	2391	22.058	255.6
36	With compositional grading	APG	Layer 4	Layers 1–6	2383	21.614	253.1
37	With compositional grading	APG	Layer 5	Layers 1–6	2370	21.390	252.3
38	With compositional grading	APG	Layer 6	Layers 1–6	2361	20.940	251.5

Table 6 (continued)

Scenario	Oil composition	Injected fluid	Completion location of injection well	Completion location of production wells	Average reservoir pressure, Psi	Ultimate oil recovery factor, %	Cumulative gas injected, MMMSCF
39	With compositional grading	50% N_2–50% CO_2	Layer 1	Layers 1–6	2347	25.918	260.8
40	With compositional grading	50% N_2–50% CO_2	Layer 2	Layers 1–6	2328	25.279	260.1
41	With compositional grading	50% N_2–50% CO_2	Layer 3	Layers 1–6	2313	24.890	259.2
42	With compositional grading	50% N_2–50% CO_2	Layer 4	Layers 1–6	2302	23.983	257.3
43	With compositional grading	50% N_2–50% CO_2	Layer 5	Layers 1–6	2296	23.332	256.2
44	With compositional grading	50% N_2–50% CO_2	Layer 6	Layers 1–6	2385	22.641	255.7
45	With compositional grading	Water-alternating-CO_2	Layer 1	Layers 1–6	3185	34.377	138.4
46	With compositional grading	Water-alternating-CO_2	Layer 2	Layers 1–6	3174	33.738	137.6
47	With compositional grading	Water-alternating-CO_2	Layer 3	Layers 1–6	3152	33.089	136.3
48	With compositional grading	Water-alternating-CO_2	Layer 4	Layers 1–6	3131	32.423	135.1
49	With compositional grading	Water-alternating-CO_2	Layer 5	Layers 1–6	3095	31.742	133.1
50	With compositional grading	Water-alternating-CO_2	Layer 6	Layers 1–6	3079	31.045	131.5

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