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Feasibility of CO_2-EOR in Shale-Oil Reservoirs: Numerical Simulation Study and Pilot Tests

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Abstract

Shale oil reservoirs such as Bakken, Niobrara, and Eagle Ford have become the main target for oil and gas investors as conventional formations started to be depleted and diminished in number. These unconventional plays have a huge oil potential; however, the predicted primary oil recovery is still low as an average of 7.5 %. Injecting carbon dioxide (CO_2) to enhance oil recovery in these poor-quality formations is still a debatable issue among investigators. In this study, three steps of research have been integrated to investigate the parameters which control the success of CO_2 huff-n-puff process in the field scale of shale oil reservoirs. Firstly, a numerical simulation study was conducted to upscale the reported experimental studies outcomes to the field conditions. The second step was to validate these numerical models with the field data from some of CO_2-EOR pilots which were performed in Bakken formation, in North Dakota and Montana regions. Finally, statistical methods for Design of Experiments (DOE) have been used to rank the most important parameters affecting CO_2-EOR performance in these unconventional reservoirs.

The Design of Experiments approved that the intensity of natural fractures (the number of natural fractures per length unit in each direction, I-direction, J direction, and K direction) and the conductivity of oil pathways (the average conductivity for the entire oil molecules path, from its storage (matrix) to the wellbore) are the two main factors controlling CO_2-EOR success in shale oil reservoirs. However, the fracture intensity has a positive effect on CO_2-EOR while the later has a negative effect. Furthermore, this study found that the porosity and the permeability of natural fractures in shale reservoirs are clearly changeable with the production time, which in turn, led to a clear gap between CO_2 performances in the lab conditions versus to what happened in the field pilots. This work reported that the molecular diffusion mechanism is the key mechanism for CO_2 to enhance oil recovery in shale oil reservoirs. However, the conditions of the candidate field and the production well criteria can enhance or downgrade this mechanism in the field scale. Accordingly, the operating parameters for managing CO_2-EOR huff-n-puff process should be tuned according to the candidate reservoir and well conditions. Moreover, general guidelines have been provided from this work to perform successful CO_2 projects in these complex plays. Finally, this paper provides a thorough idea about how CO_2 performance is different in the field scale of shale oil reservoirs as in the lab-scale conditions.

Introduction

Unconventional liquid-rich reservoirs have different aspects such as shale reservoirs, very tight reservoirs, and source rock reservoirs. Generally, these types of oil and gas reservoirs have two main criteria in common which are very small pore throats, Micro to Nano millimeters, and an ultralow permeability of Micro to Nano millidarcy as shown in **Fig. 1.** According to the recent reports, the oil production from tight formations including shale plays has shared for more than 50% of the total oil production in the US[1]. Hoffman et al., (2016) reported that 4 million barrels per day as an increment in the oil daily production in the US coming from these unconventional oil reservoirs[12]. From 2011 to 2014, Unconventional Liquid Rich (ULR) reservoirs contributed to the all natural gas growth and nearly to 92% of the oil production growth in the US[3]. This revolution in the oil and gas production has mainly happened because shale oil reservoirs have been just increasingly developed due to the advancements in horizontal wells and hydraulic fracturing techniques over the last decade. Several studies have been conducted to estimate the recoverable oil in place in these complex formations indicating huge volumes of oil. The available information refers to about 100-900 Billion barrels the oil in place in Bakken only. However, the predicted oil recovery from the primary depletion stage could lead to 7% only of the original oil in place[5]. Furthermore, some investigators argued that the primary recovery factor is still in a range of 1-2 % in some of these plays[98]. For example, the North Dakota Council reported that "With today's best technology, it is predicted that 1-2% of the reserves can be recovered"[77]. The low oil recovery happens due to the problems in the production sustainability which are the main problems in these unconventional reservoirs. The producing wells usually start with a high production rate. Then, they show a steep decline rate until they get leveled off at a low production rate. According to Yu et al. (2014), the main reason beyond the quick decline in the production rate is due to the fast depletion happening in the natural fractures combined with a slow recharge from the rock matrix (the storage)[105]. Therefore, the oil recovery factor from the primary depletion has been typically predicted to be less than 10%[3,4,7,16,88]. Infill drilling is the current practice to develop these unconventional reservoirs and to get a short-term increment in the oil production; however, the high oil rate from the new wells would not last for a long time as like as the previous wells. In addition, the cost of drilling new horizontal wells with a long lateral length is so expensive. Therefore, the infill drilling strategy might not be the economic practice in these types of reservoirs. Seeking for different options is mandatory. It is known that the main drive mechanism in the most of the shale reservoirs is the depletion drive. This drive mechanism could recover up to 8-12% of OOIP which is the main motivation to apply one of the IOR methods in these reservoirs[60]. Since these reservoirs have a huge original oil in place, any improvement in the oil recovery factor would result in enormous produced-oil volumes. Therefore, IOR methods have a huge potential to be the major starrier in these huge reserves. Although IOR methods are well understood in conventional reservoirs, they are a new concept in the unconventional formations. All basic logic steps such as experimental investigations, simulation studies, and pilot tests for examining the applicability of different IOR methods have just started over the last decade.

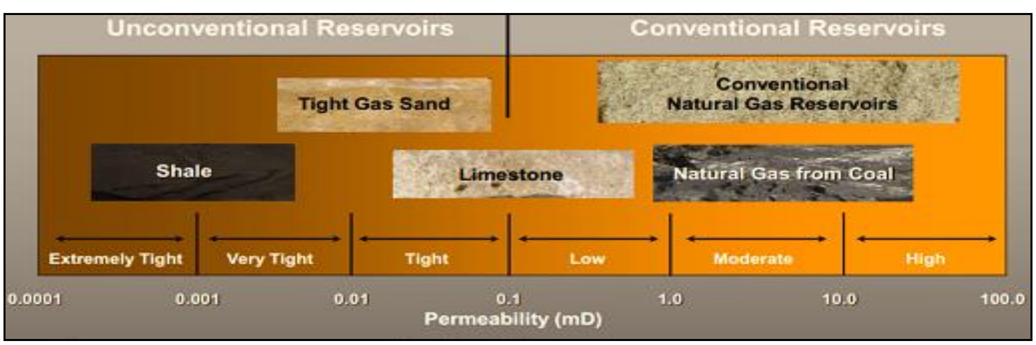
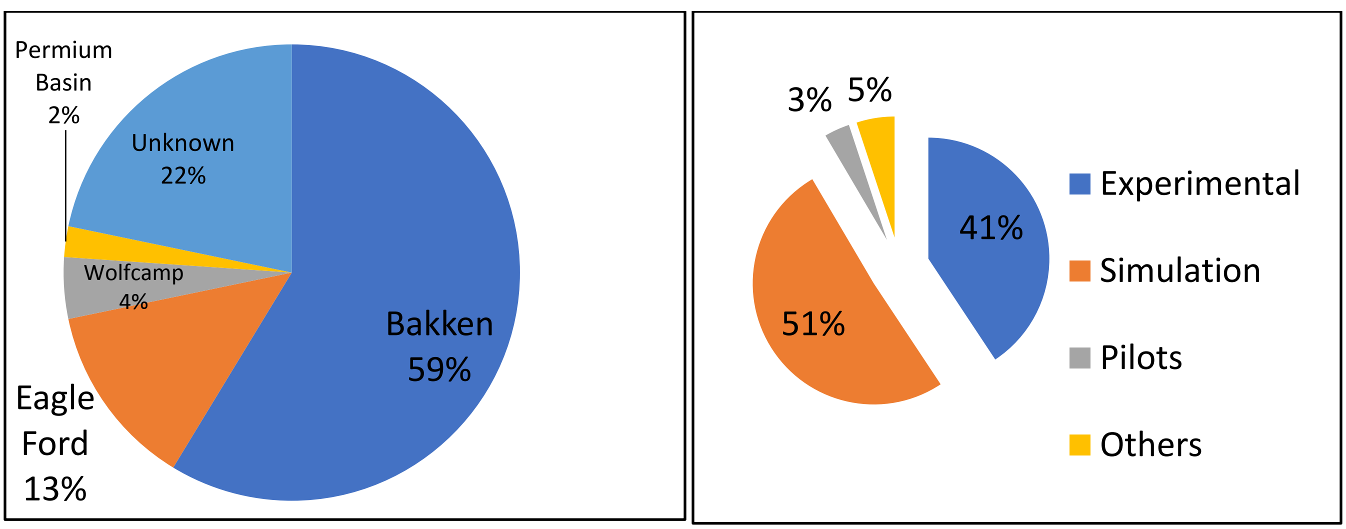


Fig. 1: Types of oil and gas reservoirs according to the permeability cut offs[5]

Classically, applying one of the feasible IOR methods in most of the oil and gas reservoirs should be mandatory to increase the oil recovery factor. However, the applications and mechanisms for IOR methods in unconventional reservoirs would not necessarily be the same as in the conventional reservoirs due to the complex and poor-quality properties of these plays. The public understanding of the main critical properties in unconventional reservoirs which might impair any IOR project is the low porosity and the ultralow permeability. Therefore, seeking for the IOR methods which are insensitive to these very small pore throats was the priority. Alfarge et al., (2017a) reviewed more than 70 reports and studies which have been conducted to investigate the applicability of different IOR methods in different unconventional formations of North America as shown in **Fig. 2A**. Different tools have been used in the reviewed studies such as experimental investigations, numerical simulation methods, pilot tests, and mathematical approaches as shown in **Fig. 2B**. Their review reported that the most feasible IOR techniques for these unconventional reservoirs are miscible gases, surfactant, and low-salinity water flooding. However, most of the previous studies recommended that miscible-gases EOR is the best technique for these types of reservoirs. The gases which have been investigated are CO_2, N_2, and natural gases. CO_2-EOR is in the top list of the miscible-gases EOR category to be applied in shale reservoirs. Furthermore, some of the IOR pilot-tests, which have been conducted to investigate the feasibility of natural gases EOR in unconventional reservoirs, showed good results in terms of enhancing oil recovery in these plays. Unfortunately, the results of the pilot-tests for CO_2-EOR, huff-n-puff process, were disappointing despite the excellent performance for CO_2 in the lab scale. Therefore, this study combined three approaches which are the reported EOR pilot-tests, the reported experimental investigations, and a new numerical simulation study to diagnose the critical parameters which control CO_2-EOR success in shale-oil reservoirs.



A-Different Formations B-Different Tools

Fig. 2: A- Different formations were studied for IOR methods applicability; B- Different tools used to investigate IOR methods applicability[1]

Background

One of the most investigated IOR methods in unconventional liquid rich reservoirs is CO_2-EOR due to different reasons. CO_2 dissolves in shale oil easily, swells the oil and lowers its viscosity. CO_2 has a lower miscibility pressure with shale oil rather than other gases such as N_2 and CH_4 [36]. However, the minimum miscible pressure of CO_2 in shale oils has a debatable range 2500-3300 psi. The reported low value for the acid number in shale oils might increase the hope to apply CO_2 EOR successfully since there would not be much danger of asphaltenes precipitation[60].

The early-published studies investigating CO_2-EOR in shale reservoirs started by using modeling methods[79, 97]. The reported models showed that 10-20% of the incremental oil could be recovered by the continuous gas flooding while 5-10% could be recovered by the huff-n-puff gas process[12]. Dong et al., (2013) reported a numerical simulation study evaluating CO_2 EOR performance in an interval of Bakken formation in the Sanish field sector[8]. They came up with a scenario to increase CO_2 injectivity in that field by drilling more horizontal injection wells. Their scenario predicted the possibility to inject 5000 Mscf/day at a maximum injection pressure of 8000 psi. From their simulation study, they found that using CO_2 injection method might increase the oil recovery factor from 5% to 24% in that field. Xu et al., (2014) evaluated the reservoir performance of Elm Coulee field in Eastern Montana under CO_2 flooding with different hydraulic fracture orientations[100]. They concluded that transverse fractures would have a higher oil recovery factor, but these transverse fractures would have a lower utilization value than the longitudinal fractures due to the breakthrough problems. Zhu et al., (2015) constructed a model in which the EOR gases could be injected into a hydraulic fracture orienated along a horizontal well and the production process could occur from an adjacent fracture which has an intersection with the same well[108]. They found a substantial improvement in the oil recovery happens by injecting CO_2 in the reservoirs which have a fluid flow from fracture to fracture. Pu et al., (2016) introduced a new model which considers capillarity and adsorption effect for the small pores of shale reservoirs[85]. They found that their model would properly simulate CO_2 EOR in unconventional reservoirs. Furthermore, the capillarity consideration in the modeling process would predict a higher oil recovery by CO_2 injection rather than the cases which would not include a capillarity property.

Regarding lab reports, Song et al. (2013) conducted experimental investigations to compare results from injecting CO_2 and water in cores from Canadian-Bakken[81]. They found that the water flooding would enhance oil recovery better than the immiscible CO_2 in the huff-n-puff process. However, miscible and near-miscible CO_2 huff-n-puff would overcome water performance in enhancing oil recovery. Hawthorne et al., (2013) investigated the mechanism beyond increasing oil recovery by injecting CO_2 in Bakken cores[54]. They proved that the diffusion mechanism is the main mechanism for CO_2 to increase oil recovery in these complex plays. However, to extract oils from the shale matrix by CO_2, long times of exposure combined with large contact areas are required. Gamadi et al., (2014) conducted an experimental work on shale cores from Mancos and Eagle Ford to investigate the EOR potential of CO_2 injection in these reservoirs[52]. Their laboratory results indicated that cyclic CO_2 injection could improve oil recovery in shale oil cores from 33% to 85% depending on types of shale cores and other operating parameters. Alharthy et al., (2015) compared the performance of injecting different types of gases such CO_2, C_1-C_2 mixtures, and N_2 on enhancing oil recovery from Bakken cores[3]. They concluded that injecting gas composed of C_1, C_2, C_3, and C_4 could produce nearly as much oil as CO_2 injection could produce which was 90% from several Middle Bakken cores and nearly of 40% from the Lower Bakken cores. Also, they found that the counter-current mechanism is the main mechanism for these gases to recover more oils from shale cores. Finally, Yu et al., (2016) investigated N_2 flooding process experimentally on Eagle Ford core plugs saturated with dead oil[103]. They examined the effect of different flooding times and different injection pressures on N_2 flooding performance. They found that more oil could be produced with a longer flooding time and higher injection pressure. **Table 1** gives a clear summary of the most significant studies which have been conducted to investigate the feasibility of miscible-gases EOR techniques in these unconventional reservoirs.

It is clear from the previous studies that CO_2 would have a great potential to enhance oil recovery in these poor-quality reservoirs. However, whether using CO_2 in Huff-n-Puff process or injecting CO_2 in flooding scenario is still debatable. Due to the low permeability, conformance problems in these reservoirs, and the significant molecular-diffusion rate for CO_2 reported in lab conditions, most of the researchers prefer the CO_2 Huff-n-Puff process on CO_2 flooding. Unfortunately, the results of the pilot tests for CO_2-EOR in the cyclic process were disappointing[12]. One of the main reasons for the poor performance for CO_2-EOR in the field scale might be due to the wrong prediction for CO_2 diffusion mechanism. A detailed study for determining the level of CO_2 diffusivity in the real field conditions have been conducted in this work. Identifying the CO_2 diffusivity level is the key to the success or failure of the CO_2-EOR technique in shale oil reservoirs.

Table 1: The reported studies for miscible-gases EOR in unconventional reservoirs

SN	Authors, Year	Paper n.	Approach	Formation	IOR Method	IOR Mechanism
1	Kovscek et al. 2008	SPE-115679-MS	Experimental	Siliceous shale reservoir core	CO_2	Diffusion
2	Shoaib et al. 2009	SPE 123176	Simulation	Bakken	CO_2	pressure maintenance
3	Vega et al. 2010	SPE -135627-MS	Experimental/Simulation	siliceous shale Core	CO_2	Diffusion
4	Hoteit et al. 2011	SPE 141937-MS	Mathematical Approach	X	CO_2	diffusion
5	Hoffman et al. 2012	SPE 154329	Simulation	Bakken	CO_2/ Natural Gas	X
6	Dong et al. 2013	SPE-168827-MS	Simulation	Bakken	CO_2	X
7	Hawthorne et al. 2013	SPE-167200 -MS	Experimental	Bakken	CO_2	Extraction
8	Tao Wan et al. 2013	SPE 168880	Simulation	Eagle Ford	CO_2	Oil Viscosity reduction and Pressure m.
9	Xu et al. 2013	SPE 168774-MS	Simulation	Bakken	CO_2	pressure maintenance
10	Kurtoglu et al. 2013	SPE-168915-Ms	overview/ Simulation	Bakken	CO_2	Oil Viscosity reduction and swelling
11	Chen et al. 2013	SPE-164553-MS	simulation	Bakken	CO_2	X
12	Tovar et al. 2014	SPE-169022-MS	Experimental	preserved side-wall core X	CO_2	Diffusion/Reduction in Capillary forces
13	Chen et al. 2014	SPE-164553-PA	Simulation	Bakken	CO_2	Diffusion
14	Gamadi et al. 2014	SPE-169142-MS	Experimental	Mancos and Eagle Ford.	CO_2	Repressurization
15	Schmidt et al. 2014	21-1921 WPC	Pilots	Bakken	Natural gas	Displacement oil in matrix
16	Tao Wan et al. 2014	SPE-169069-MS	Simulation	Eagle Ford	CO_2	Oil viscosity reduction and Pressure m.
17	Adekunle, O. 2014	PhD dissertation/CSM	Experimental/Simulation	Bakken	CO_2/NGL	X
18	Fai-Yengo et al. 2014	URTeC:1922932	Simulation	Bakken	CO_2	Combination
19	Sheng et al. 2014	JNGSVolume 22, January 2015, Pages 252–259	Simulation	X	CO_2	X
20	Alharthy et al. 2015	SPE-175034-MS	Experimental/Simulation	Bakken	CO_2	Diffusion
21	Tao Wan et al. 2015	SPE 1891403-PA	Simulation	Eagle Ford	CO_2	Diffusion mechanism
22	Alharthy et al. 2015	PhD dissertation/CSM	Experimental/Simulation	Bakken	CO_2/NGL	Swelling, Repressurization, Diffusion
23	Sheng et al. 2015	2015-438 ARMA Conference Paper - 2015	Simulation	Wolfcamp shale	Gas	X
24	Hoffman et al. 2016	SPE-180270-MS	Pilots	Bakken	CO2/Water flooding	X
25	Pu et al. 2016	SPE-179533-MS	Simulation	Bakken	CO_2	Capillarity and Adsorption
26	Yang et al., 2016	SPE-180208-MS	Simulation	Eagle Ford	CO_2	CO2 Adsorption
27	Yu et al., 2016	SPE-180378-MS	Experimental	Eagle Ford	N_2	Repressurization and fracturing
28	Yu et al., 2016	SPE-179547-MS	Experimental	Eagle Ford	N_2	Repressurization

Miscible-Gases Pilot Projects

Although there are a few pilots conducted to investigate the applicability of miscible-gases EOR in shale oil reservoirs, this section provides the published results for the pilots which have been mainly conducted in US and Canada. The start point is with the IOR projects which have been conducted in Canadian Bakken. The interesting point is that the pilot tests which have been conducted in Canadian Bakken have approximately the same well pattern, Toe-Heel pattern. Furthermore, the most interesting criteria in these pilots, rather than the pilots which have been conducted in US Bakken, is that the spacing between the injection wells and production wells is very short as 200 ft although the porosity and permeability of Canadian Bakken are much higher than those for US Bakken. This spacing between injectors and producers is much shorter than the spacing between injectors and producers in the pilot tests which have been performed in US Bakken (Alfarge et al., 2017a). This short spacing might be one of the main reasons beyond the encouraging results of the pilot tests in Canadian Bakken. The lateral length for the production and injection wells which were drilled horizontally in Canadian Bakken is approximately equal to one mile. Although the injection process in those pilots was sporadical, any injectivity problems had not been reported. Schmidt et al., (2014) reported a successful project in the Canadian Bakken[22]. Their pilot project covered 1280 acres which were developed by a combination of 80-acre and 160-acre spacing. The fluid and rock properties for their project are shown in **Table 2**. They designed their project by a one-mile horizontal injector and nine perpendicular horizontal producers. The wells pattern was Toe-Heel pattern. Natural gas (primary methane) was used as injectant due to its availability in these reservoirs, its high compressibility, and its low viscosity. They injected a lean gas (with C_2-C_7 content in the range of 138 bbl/MMCF to 145 bbl/MMcf) at an injection rate of 350-1000 Mscf/day without any reported problems in the injectivity. The reported results of their pilot were encouraging in all nine offset producers where the oil production rate increased from 135 bbl/day to 295 bbl/day as shown in **Fig. 3**. However, there were some problems related to conformance control where some early injected gases got a breakthrough in some of the producers. The gas utilization value had been improved form 10 MCF/bbl to 6.5 MCF/bbl which is very well consistent with the model prediction provided by Alfarge et al. (2017b)[2]. The results from their pilot are motivating. However, the main reasons for the success of their project might be because that Canadian Bakken has a permeability with 1-2 orders of magnitude higher than the permeability for US Bakken and a porosity as a twice larger than that for US Bakken[12]. Furthermore, the short spacing between the injectors and producers could be considered another reason for the success of these pilots.

Table 2: Summary of fluid and rock properties of project area in Canadian Bakken[22]

Parameter	Value	Unit
Pilot Area	1280	Acres
Net Pay	23-26	ft
Porosity	9-10	%
Permeability	0.01-0.1	md
Water Saturation	55-59	%
Original Formation Volume Factor	1.328	Rb/STB
Bubble Point Pressure	990	psi
Oil Viscosity	2-3	cP
Oil Gravity (Stock Tank)	42	API
OOIP (Pilot Area)	8000	MSTB

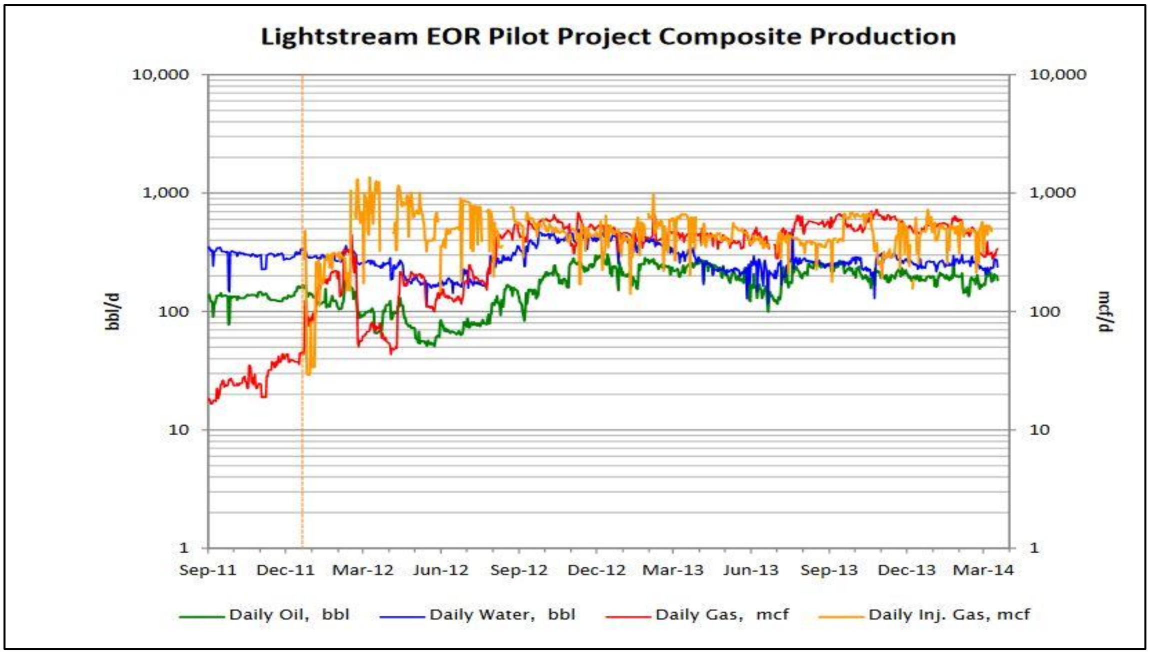


Fig. 3: Performance of natural gas EOR in Canadian-Bakken conditions[22]

Hoffman et al., (2016) reported seven IOR pilot-tests conducted in US Bakken, performed in North Dakota and Montana. Four of these seven pilots injected gases[12]. Three of those four pilots injected CO_2 while the fourth one injected enriched natural-gas. Some of those pilots were performed as a huff-n-puff process while others were designed in the continuous injection process. **Table 3** shows the pilots distribution and the fluid type injected. The start point is from the projects which were performed in huff-n-puff tests. Pilot test#1 and pilot test#2 were conducted in different parts of US Bakken by two different operators. They injected CO_2 as a huff-n-puff process. Both of them did not show problems related to the injectivity where they injected 1000 Mscf/day and 1500-2000 Mscf/day at 2000-3000 psi respectively. However, a clear production increment for any of them had not been well recognized as shown in **Fig. 4**. Pilot test#5 was conducted in a vertical well with 60 ft of middle Bakken pay-thickness to perform a CO_2 cyclic process. They injected 300-500 Mscf/day of CO_2 for 20-30days. After that, they did shut in the well for 20 days, then the production process was resumed. They observed the injected CO_2 produced in an offset well which was 900 ft away from the injection well. It is clear that the operators fractured the vertical well at that high flowrate, so they stopped the operations. The continuous gas injection process had been performed in the pilot test#7. The pilot test#7 has one injector in the center surrounded by four offset wells. Two of the producers which were to the east and the west were located at 2300 ft away from the injector while the other two which were to the north and south were located at 900 ft and 1200 ft respectively away from the injector. They injected an enriched natural gas with approximately 55% methane, 10% nitrogen, and 35% of C_{2+} fractions. The injection rate was 1600 Mscf/day for 55 days at a target surface injection pressure equals to 3500 psi. As a result, all four offset wells had an increment in the production oil rate. However, some people argued whether that oil increment from the injection process or from the frac hits which were going on in the neighboring wells. Once again, the natural gas EOR like what happened in the Canadian Bakken approved to be a promising technique in these reservoirs. To sum up, the reported pilot-tests which used natural gas as injectant were successful. However, CO_2-EOR did not show a clear success in the huff-n-puff process which might give a clear indication that the proposed CO_2 diffusion mechanism in lab conditions is not the same as in the field conditions.

Table 3: Summary of pilot tests in the Bakken-North America[12]

Name	State	Year	Fluid	Type
Pilot Test #1	ND	2008	CO2	Huff-n-puff
Pilot Test #2	MT	2009	CO2	Huff-n-puff
Pilot Test #3	ND	2012	Water	Huff-n-puff
Pilot Test #4	ND	2012-2013	Water	Flood
Pilot Test #5	ND	2014	CO2	Vertical inj.
Pilot Test #6	MT	2014	Water	Flood
Pilot Pilot#7	ND	2014	Nat. gas	Flood

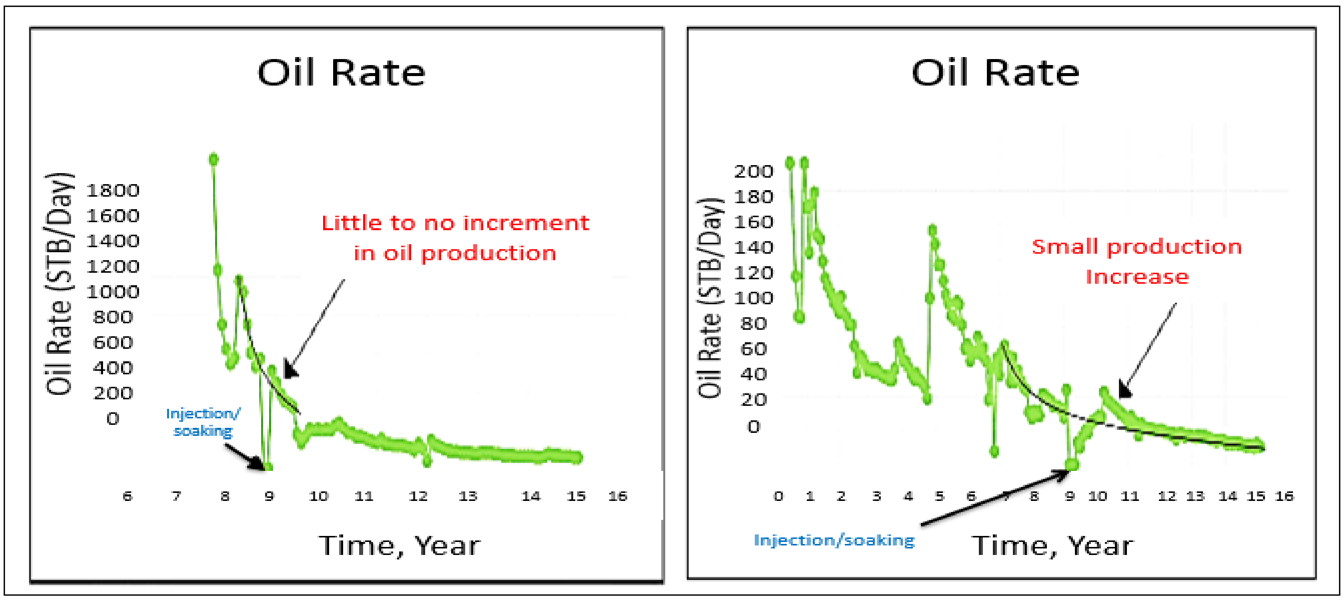


Fig. 4: Oil production from two Bakken wells performed CO_2-EOR in huff-n-puff process[12]

Molecular Diffusion

Gravity drainage, physical diffusion, viscous flow, and capillary forces are the common forces which control the fluids flow in the porous media. However, one force might eliminate the contributions of other forces depending on the reservoir properties and operating conditions. Molecular diffusion is defined as the movement of molecules caused by Brownian motion or composition gradient in a mixture of fluids[18]. This type of flow would be the most dominated flow in the fractured reservoirs with a low-permeability matrix when gravitational drainage is inefficient[18, 19]. It has been noticed and approved that gas injection is the most common EOR process affected by the molecular-diffusion considerations. Ignoring or specifying incorrect diffusion rate during the simulation process can lead to overestimate or underestimate the oil recovery caused by the injected gas. This happens not only due to the variance in the miscibility-process between the injected-gas and the formation-oil but also due to the path change for the injected gas species from the fractures to the formation-matrix.

The Péclet number (Pe) is a class of dimensionless numbers which has been used to measure the relative importance of molecular diffusion flow to the convection flow. This number can be calculated as shown in **Eq. 1**. If Pe number is less than 1, the molecular diffusion is the dominant flow. However, if Pe is greater than 50, convection is the dominant flow. The dispersion flow is dominant when Pe in a range of 1 to 50 (Hoteit and Firoozabadi, 2009).

$$\mathbf{Pe} = \frac{diffusion\ time}{convection\ time} = (L2/D)/(L/v) = Lv/D \quad (1)$$

Where v is the bulk velocity, L is a characteristic length, and D is the molecular diffusion coefficient.

CO_2 Molecular-Diffusion Mechanism

Different mechanisms have been proposed for the ability of the injected CO_2 to improve oil recovery in unconventional reservoirs as shown in **Table 4**. However, since the matrix permeability in these unconventional reservoirs is in a range of (0.1 –0.00001 mD), CO_2 would not be transported by convection flux from fracture to matrix[105]. The main transportation method for the injected CO_2 is depending on the difference in the concentration gradient between the concentration of CO_2 in the injected gases and the concentration of CO_2 in the target-oil. This process of transportation is subjected to Fick's law. The mechanism which is responsible for this process is called the molecular diffusion mechanism. The molecular diffusion process would be more dominated in the tight reservoirs with a significant heterogeneity. Hawthorne et al., (2013) extensively investigated the CO_2 diffusion-mechanism in Bakken cores and they proposed five conceptual-steps to explain it[54]. Those conceptual steps include: (1) CO_2 flows into and through the fractures, (2) an unfractured rock matrix is exposed to CO_2 at fracture surfaces, (3) CO_2 permeates the rock driven by pressure, carrying some hydrocarbon inward; however, the oil is also swelling and extruding some oil out of the pores, (4) oil migrates to the bulk CO_2 in the fractures via swelling and reduced viscosity, and (5) as the CO_2 pressure gradient gets smaller, oil production is slowly driven by concentration-gradient diffusion from pores into the bulk CO_2 in the fractures. The importance of considering this mechanism is also depending on the type of injected gases. For example, the shale oil has a high concentration of light components for natural gases such as methane. In the same time, the shale oil has a low concentration of CO_2. Therefore, considering this mechanism in the simulation process for the injected CO_2 has a significant effect on the obtained oil recovery. However, considering this mechanism in the simulation process for the injected methane has a miner effect on the obtained oil recovery[111]. The effect of the binary molecular diffusion between the injected CO_2 and the formation oil was simulated in this work by using the experimental correlation conducted by Sigmund (1976a; 1976b)[112-113]. The following polynomial equation was fitted with their observed experimental values.

$$D_{ij} = \frac{\rho_k^0 D_{ij}^0}{\rho_k} (0.99589 + 0.096016\rho_{kr} - 0.22035\rho_{kr}^2 + 0.032874\rho_{kr}^3 \quad (2)$$

Where D_{ij} is the binary diffusion coefficient in unit of cm^2/s between component i and j in the mixture, $\rho^o D_{ij}^o$ is the zero-pressure limit of the density-diffusivity product, ρ_k is the density of the diffusion mixture in kg/m^3, ρ_{kr} is the reduced density which can be calculated by **Eq. 3**, and the subscript k denotes the phase which could be water, oil, or gas. In the simulator, the product of mixture density and diffusion coefficient can be calculated by **Eq. 4**. The diffusion coefficient of component i in the mixture can be calculated by **Eq. 5.**

$$\rho_{kr} = \rho_k \frac{\sum_i^{nc} y_{ik} v_{ci}^{5/3}}{\sum_i^{nc} y_{ik} v_{ci}^{2/3}} \tag{3}$$

Where y_{ik} is the mole fraction of i species in phase k; and v_{ci} is the critical volume of i species.

$$\rho_k^0 D_{ij}^0 = \frac{0.18583\, T^{0.5}}{\sigma_{ij}^2 \mho_{ij}\, R} \cdot \{\frac{1}{M_i} + \frac{1}{M_j}\}^{0.5} \tag{4}$$

Where R is the universal gas constant, T is the temperature; M is the molecular weight, σ_{ij}^2 is the collision diameter between i and j, and $\mho_{ij}$ is the collision integral of the Lenard-Jones potential.

$$D_i = \frac{1-y_i}{\sum_{i\neq j} y_i D_{ij}^{-1}} \tag{5}$$

Where D_i is the diffusion coefficient of component i in the mixture and y_i is the mole fraction of component i.

Table 4: The proposed CO2 EOR mechanisms for improving oil recovery in unconventional reservoirs

CO_2 mechanism	Approach tool
1-Diffusion	Lab
2-Reduction in Capillary forces	Lab and simulation
3-Repressurization	Lab
4-Extraction	Lab
5-Oil swelling and pressure maintenance	Lab and simulation
6-Oil Viscosity reduction	Lab and simulation
7-Combination of more than one mechanism from above	-

Most of the previous experimental studies reported that CO_2 diffusion mechanism is beyond the increment in the oil recovery obtained in the lab conditions. Then, the observed increment in the oil-recovery and/or the CO_2 diffusion-rate obtained in the lab conditions were upscaled directly to the field scale by using numerical simulation methods. This direct upscaling methodology might be so optimistic because the lab-cores have a higher contact area and longer exposure time to the injected CO_2 than what might happen in the real-conditions in the field scale. As a result, both of the previous simulation studies and the experimental reports might be too optimistic to predict a quick improvement in the oil recovery from injecting CO_2 in these tight formations.

Numerical Simulation

Most of the reported simulation studies in this area simulated these naturally fractured shale reservoirs by a combination of discrete fractures with a tight formation matrix. They used the refinement process for the grids around the discrete fractures to make the convergence in the numerical calculations happening. We think that their combination, discrete fractures with tight formation matrix, would not capture the real physics for these fractured shale reservoirs. In this simulation study, the LS-LR-DK (logarithmically spaced, locally refined, and dual permeability) model is built to simulate the CO_2-EOR in shale reservoirs. The LS-LR-DK method can accurately simulate the fluid flow in fractured shale-oil reservoirs[88]. Furthermore, the representation of the molecular-diffusion mechanism in the previously reported simulation methods would also be misleading because most of the previous studies used the direct upscaling for the lab observations, diffusion coefficients and/or oil increment resulted from CO_2 injection in the lab cores. In this paper, an advanced general equation-of-state compositional simulator has been used to build the formation fluid model. Then, both of the models, LS-LR-DK model and fluid model, have been combined to simulate compositional interactions of the reservoir fluid and the injected CO_2 during enhanced oil recovery processes. Furthermore, the implementation of the diffusion model in the LS-LR-DK model and fluid model has been conducted. In this study, we tried to build a numerical model which has the typical fluid and rock properties of Bakken formation, one of the most productive unconventional formations in the US. All of the simulation processes have been carried out by using CMG-GEM simulator. In the models of this study, we injected CO_2 in different scenarios as Huff-n-Puff process through hydraulically fractured well in Bakken formation. All the mechanisms which were proposed in **Table 4** have been considered in this model. In this field case study, the production well was stimulated with 5 hydraulic fractures. The spacing between the hydraulic fractures is 200 ft. The simulated model includes two regions which are stimulated reservoir volume (SRV) and un-stimulated reservoir volume (USRV) as shown in **Fig. 5**. The dimensions of the reservoir model are 2000 ft x 2000ft x42 ft, which corresponds to length, width, and thickness respectively. The dimensions of the fractured region are 5 fractures with half-length of 350 ft in J direction, width 0.001 ft in I direction, and fracture height of 42 ft in K direction. Fracture conductivity is 15 mD.ft. The other model input parameters are shown in **Table 5**.

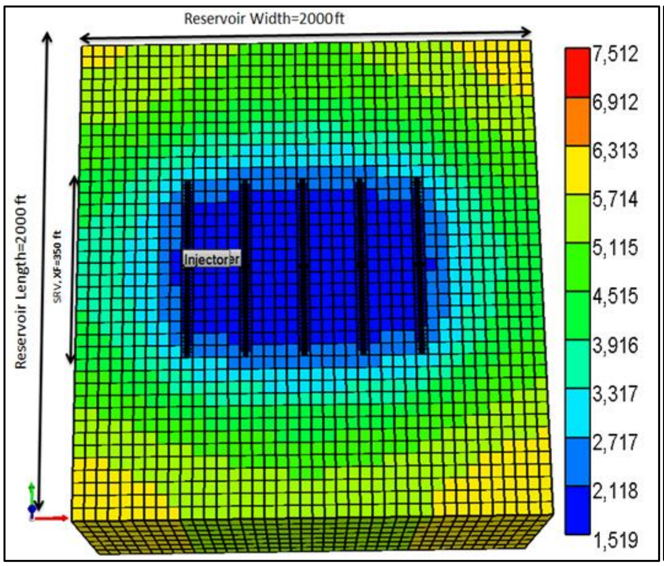


Figure 5a- Average Pressure in a depleted well in Bakken

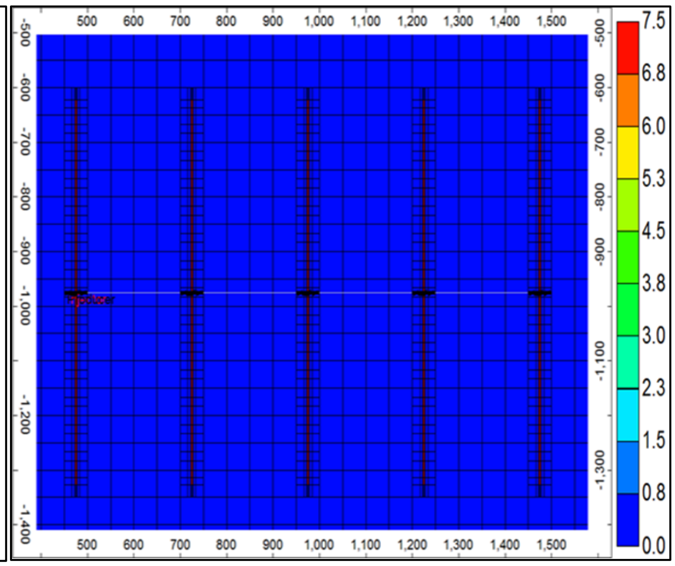


Figure 5b- A closed view for SRV of Production well

Table 5: Model input parameters for the base case

Parameter	value	Unit
The model dimensions	2000x2000x42	ft
Production time	20	year
Top of reservoir	8000	ft
Reservoir temperature	240	ºF
Reservoir pressure	7500	psi
Initial water saturation	0.3	value
Total compressibility	$1x10^{-6}$	psi^{-1}
Matrix permeability	0.005	mD
Matrix porosity	0.085	value
Horizontal well length	1000	ft
Total number of fractures	5	value
Fracture conductivity	15	mD-ft
Fracture half-length	250	ft
Fracture Height	42	ft

Compositional Model for the Formation Fluids

The typical Bakken oil has been simulated in this study. The oil which was used in this model has 42 API°, 725 SCF/STB, and 1850 psi as oil gravity, gas oil ratio, and bubble point pressure respectively. It is known that compositional models are the most time-consumed models' due to the large number of components in the typical formation oil. In our model, we have 34 components so that would take a long time for the simulator to complete running one scenario. The common practice in the numerical simulations for such situation is the careful lump for the reservoir oil components into a short representative list of pseudo-components. These pseudo components could be acceptable if they have matched with the laboratory–measured phase behavior data. The supplied data for such compositional models need to have a description of associated single carbon numbers and their fractions, saturation pressure test results, separator results, constant composition expansion test results, differential liberation test results, and swelling test results[7]. These steps can be used for tuning the EOS to match the fluid behavior. WinProp-CMG has been used to lump the original 34 components into 7 pseudo components as shown in **Table 6**. WinProp is an Equation-of-State (EOS)-based fluid behavior and PVT modeling package. In WinProp, the laboratory data for fluids can be imported and an EOS can be tuned to match the physical behavior for the lab data. Fluid interactions can be predicted and a fluid model can be then created for the use in CMG software[7]. **Table 7** presents the Peng-Robinson EOS fluid description and binary interaction coefficients of the Bakken crude oil with different injected gases. **Fig. 6** represents the two-phase envelope for the Bakken oil which was generated by using WinProp-CMG.

Table 6: Compositional data for the Peng-Robinson EOS in the model oil

Component	Mole fraction	Critical pressure (atm)	Crititical Temp. (K)	Acentric Factor	Molar Weight (g/gmole)
CO2	0	7.28E+01	3.04E+02	0.225	4.40E+01
N2-CH4	0.2704	4.52E+01	1.90E+02	0.0084	1.62E+01
C2H-NC4	0.2563	4.35E+01	4.12E+02	0.1481	4.48E+01
IC5-CO7	0.127	3.77E+01	5.57E+02	0.2486	8.35E+01
CO8-C12	0.2215	3.10E+01	6.68E+02	0.3279	1.21E+02
C13-C19	0.074	1.93E+01	6.74E+02	0.5672	2.20E+02
C20-C30	0.0508	1.54E+01	7.92E+02	0.9422	3.22E+02

Table 7: Binary interaction coeficients for Bakken oil

Component	CO2	N2-CH4	C2H-NC4	IC5-CO7	CO8-C12	C13-C19	C20-C30
CO2							
N2-CH4	1.01E-01						
C2H-NC4	1.32E-01	1.30E-02					
IC5-CO7	1.42E-01	3.58E-02	5.90E-03				
CO8-C12	1.50E-01	5.61E-02	1.60E-02	2.50E-03			
C13-C19	1.50E-01	9.76E-02	4.24E-02	1.72E-02	6.70E-03		
C20-C30	1.50E-01	1.45E-01	7.79E-02	4.27E-02	2.51E-02	6.00E-03	

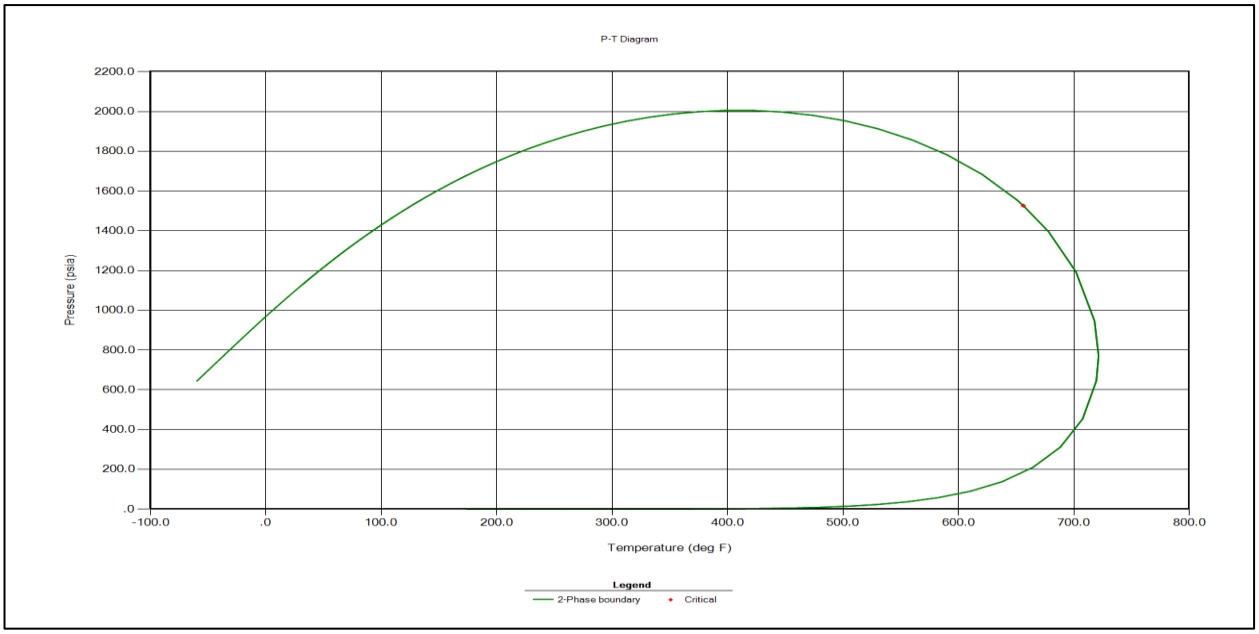


Fig. 6: The two-phase envelope for Bakken oil which was generated by WinProp-CMG

Results and Discussion

Natural Depletion for Bakken Model. The reservoir model was initially run in natural depletion for 7300 days (20 years). The production well, which was hydraulically fractured, was subjected to the minimum bottom-hole pressure of 1500 psi. The simulated Bakken well performance in the natural depletion is shown in **Fig. 7**. In the natural depletion scenario, it has been clear that the production well started with a high production rate initially as shown in **Fig. 7**. Then, it showed a steep decline rate until it got leveled off at a low rate. This is the typical trend to what is happening in the most if not all unconventional reservoirs of North America. If we investigate the pressure distribution in the reservoir model as shown in **Fig. 5**, it is clear that the main reason to that fast reduction in the production rate is due to the pressure depletion in the areas which are close to the production well. However, the reservoir pressure is still high in the areas which are far away from the production well. This explains the poor feeding from neighboring areas in these types of reservoirs due to the what is called the permeability gel (tight formations).

Flow-Type Determination in the Natural-Depletion Stage. We calculated the Péclet number locally in each grid of the model. In the formation-matrix areas, the results indicated that Péclet number is away below 1 for both of gas phase and oil phase which means that the diffusion flow is the most dominant flow in the formation matrix as shown in **Fig. 8.** However, in the hydraulic fractures areas, the viscous flow is clearly dominated where Pe is away above 100. In the natural fractures areas, the results indicated that Péclet number is significantly changeable where it is away below 1 in the areas which are far away from hydraulic fractures; however, it is away above 100 in the areas which are close to the hydraulic fractures as shown in **Fig. 9**. According to the average value of Péclet number in the natural fractures areas, the dispersion flow could be the most dominant flow.

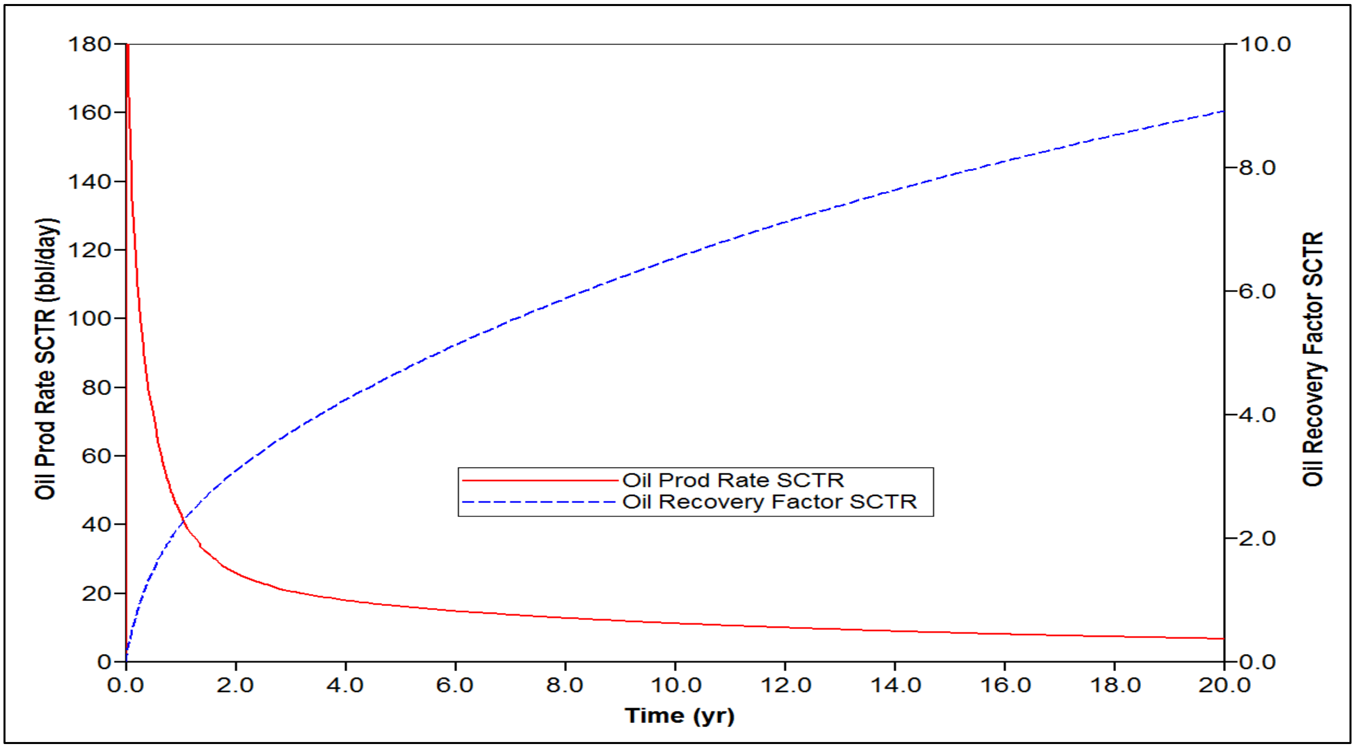
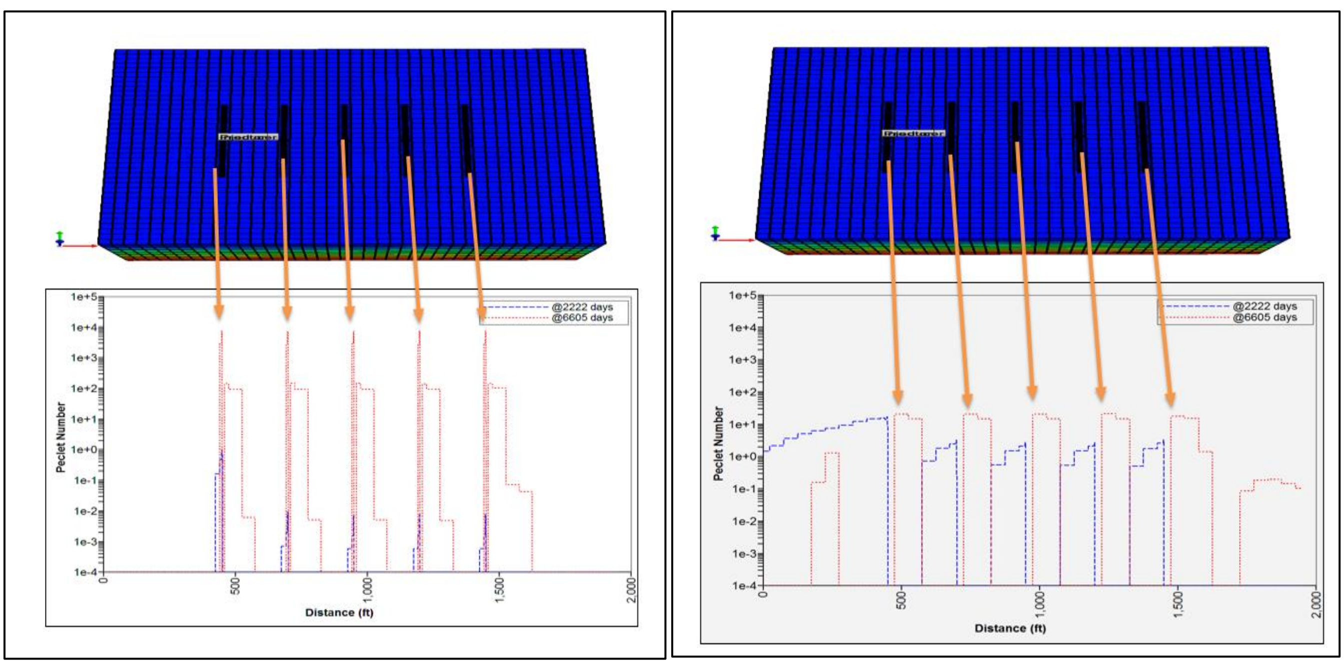
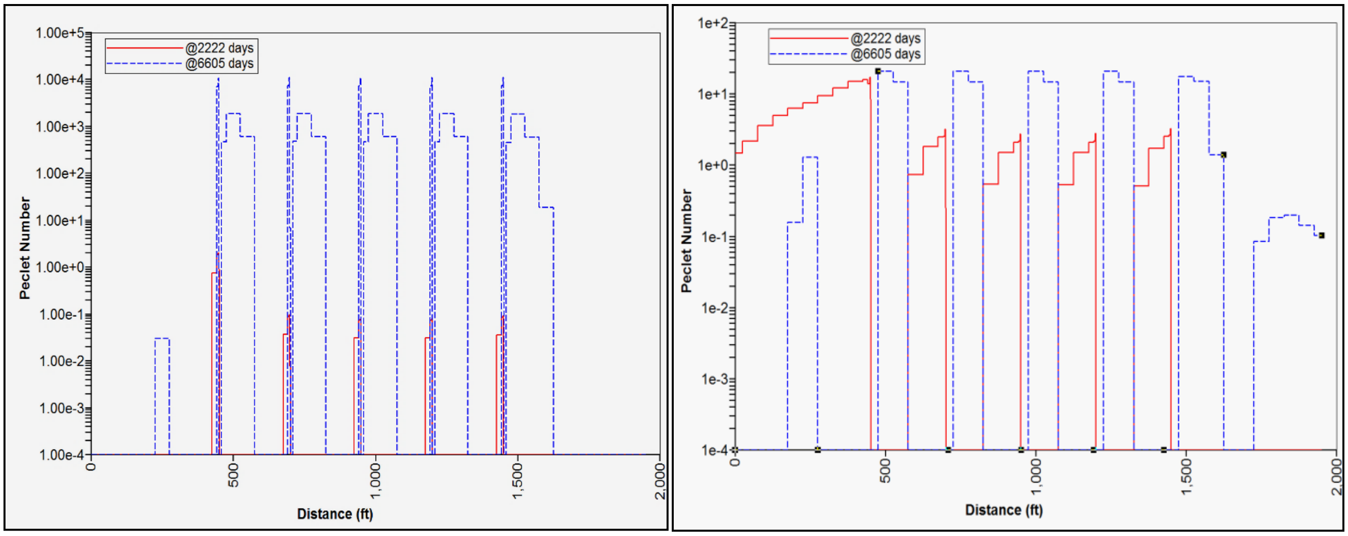


Fig. 7: The reservoir performance in natural depletion conditions



A-Gas Phase B-Oil Phase

Figure 8: Péclet number distribution a long cross section in the matrix-model



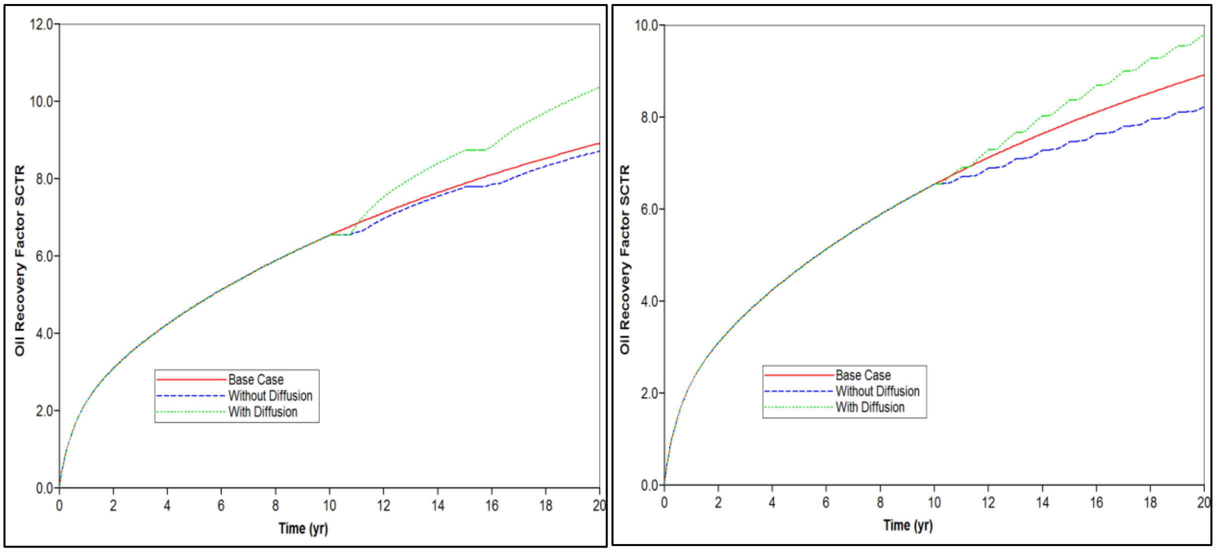
A-Gas Phase B-Oil Phase

Figure 9: Péclet number distribution a long cross section in the natural fracture-model

Effect of Huff-n-Puff Cycles-Number on CO_2 Performance. CO_2 was injected in the production well as a huff-n-puff process in two different scenarios as shown in **Table 8**. Each scenario has two cases: (1) The first case is injecting CO_2 assuming there is no molecular-diffusion mechanism for the injected CO_2 into formation-oil, (2) The second case is injecting CO_2 with molecular diffusion mechanism enabled. The results indicated that the CO_2 performance for without-molecular diffusion case did not provide any improvement in the oil recovery from what was obtained at natural depletion production; it is even worse than the base case for both scenarios as shown in **Fig. 10**. If we look closely, we found that the enhancement in the oil production rate from CO_2 injection did not offset the loss in the oil production, which was happening during the soaking and injection period. This can be noticed by observing the difference in the slope of oil recovery curves, before and after injecting CO_2. However, CO_2-EOR, in with the molecular-diffusion cases, has improved the oil recovery and oil production in a significant way as shown in **Fig. 10**. However, the results indicated that the CO_2 performance is independent of huff-n-puff cycles-number for the with-diffusion cases. We can notice that the oil recovery obtained for both scenarios, for the with-diffusion cases, is almost the same for both scenarios as shown in **Fig. 10**. However, for without-diffusion cases, the more cycles of CO_2 huff-n-puff process is the worst. This can be explained by the soaking period. The soaking period for the scenario which has 2 cycles is longer than that for the 10-cycle scenario. The injected CO_2 needs longer soaking periods to perform well in such tight reservoirs.

Table 8: The agenda and time breakdown for both CO_2 huff-n-puff scenarios

Scenario 1	**Scenario 2**
2 cycles injected	10 cycles injected
The injection time for each cycle=6 months	The injection time for each cycle=2 months
Injection rate= 500 Mscf/day	Injection rate=500 Mscf/day
Soaking period=3 months	Soaking period=1 months
The production for each cycle=4 years and 3 months	The production for each cycle=9 months



A-Scenario 1 **B-Scenario 2**

Fig. 10: Oil recovery factor in natural depletion conditions versus with CO_2 Huff-n-Puff

If we investigate the reasons beyond the role of molecular-diffusion mechanism on CO_2 performance to enhance oil recovery in these tight formations, we found this mechanism makes CO_2 penetrate deeper into the tight matrix, far way from the hydraulic fractures as shown in **Fig. 11**. However, the case of CO_2 injection which does not have a diffusion capacity makes the CO_2 penetrate just in the limited areas around the hydraulic fractures. Therefore, for the cases in which CO_2 penetrate deeper in the tight matrix, CO_2 would swell more volumes of oil, reduce oil viscosity, and finally produce larger quantities of oil by the counter-current mechanism. On the other hand, in the cases which have CO_2 with a low molecular-diffusion rate, the injected CO_2 would be produced back in the same well very soon. Therefore, producing the injected CO_2 back would put another hold on the oil production due to the slippage effect making the enhancement in the oil production from these types of reservoirs even worse.

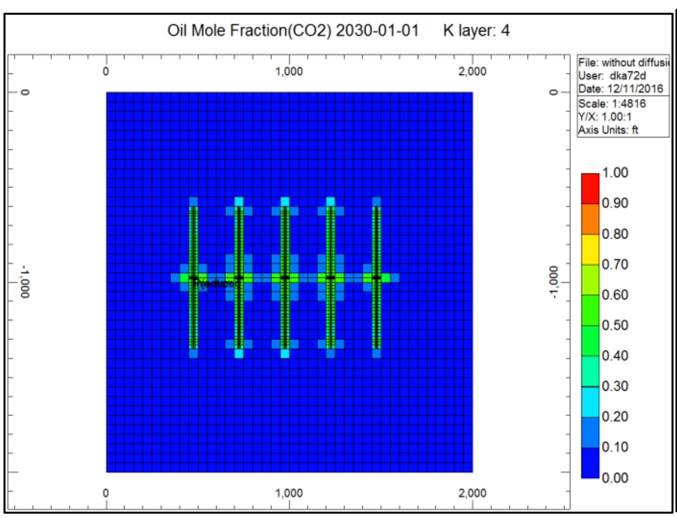


Fig. 11a- CO_2 Injection without-molecular diffusion

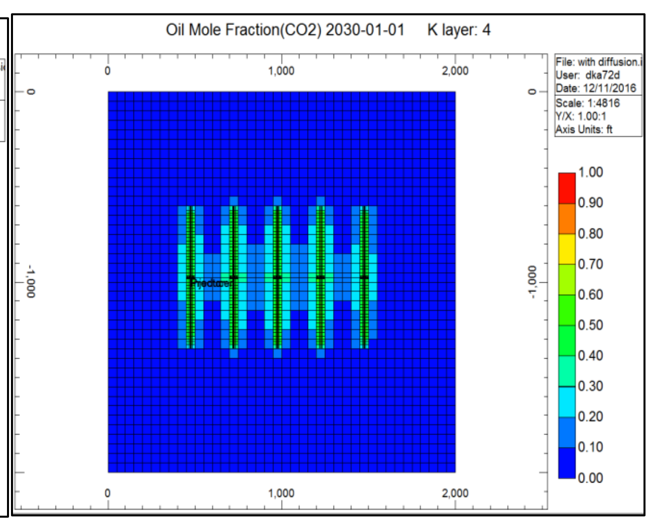


Fig. 11b- CO_2 Injection with Molecular Diffusion

Parameters Affecting the Molecular-Diffusion Mechanism for CO_2-EOR

The Exposure Time between the injected CO_2 and the Formation-Fluid. To investigate the effect of the exposure time between the formation oil and the injected-CO_2 on the CO_2- molecular diffusion mechanism, different soaking periods have been used for the same scenario. The results confirmed the prediction which is that CO_2 would perform better in the cases which have a longer soaking period rather than the cases which have a short soaking period as shown in **Fig. 12**. Another verification has been conducted to verify the effect of the exposure time on the CO_2-molecular diffusion. This verification has been done by injecting CO_2 in the low-conductivity hydraulic fractures versus injecting CO_2 in the high-conductivity hydraulic fractures. The results indicated that the injected CO_2 would enhance oil recovery in the reservoirs with low-conductivity fractures more than the reservoirs with high-conductivity fractures. To sum up, as far as the kinetics of the oil recovery process in the productive areas do not exceed the CO_2-diffusion rate, the injected CO_2 would experience more exposure time with the formation oil before its being produced back.

The Contact Area between the Injected CO_2 and the Formation-Fluid. If we need to enhance the CO_2-molecuar diffusion in these formations, we need to have a large contact area between the injected CO_2 and the formation oil. This can be verified by running some of the model scenarios which have a different contact area between the formation oil and the injected CO_2. We did that investigation by running two models which have exactly the same rock and fluid properties. However, one of them injected CO_2 in hydraulically fractured well (large contact area) while the other one injected CO_2 in non-hydraulically fractured well (small contact area). The results confirmed the prediction which is that CO_2 would perform better in the hydraulically fractured well rather than the non-hydraulically fractured well as shown in **Fig. 13** and **Fig. 14**. Another verification has been done by injecting CO_2 into an open-hole well versus injecting CO_2 into a cased hole. Also, the results confirmed the prediction which is that CO_2 would perform better in an open- hole horizontal well rather than a cased-horizontal well.

Performing Time. To investigate the effect of the performing time on CO_2-EOR performance, we injected CO_2 at a different time from the production well life. In the first scenario, we injected CO_2 after 5 years of the production life. However, in the second scenario, we injected CO_2 after 10 years from the production life. The results confirmed the prediction which is that CO_2 would perform better in the cases which have early CO_2-EOR rather than the cases which have late CO_2-EOR as shown in **Fig. 15**. This could be explained by the effective-stress principle which might be significantly important to control the permeability and porosity of natural fractures in shale oil reservoirs. As far as the CO_2-EOR performed earlier, its performance would be better because the injected CO_2 would find a good intensity of natural fracture which helps in enhancing its diffusivity into formation-oil.

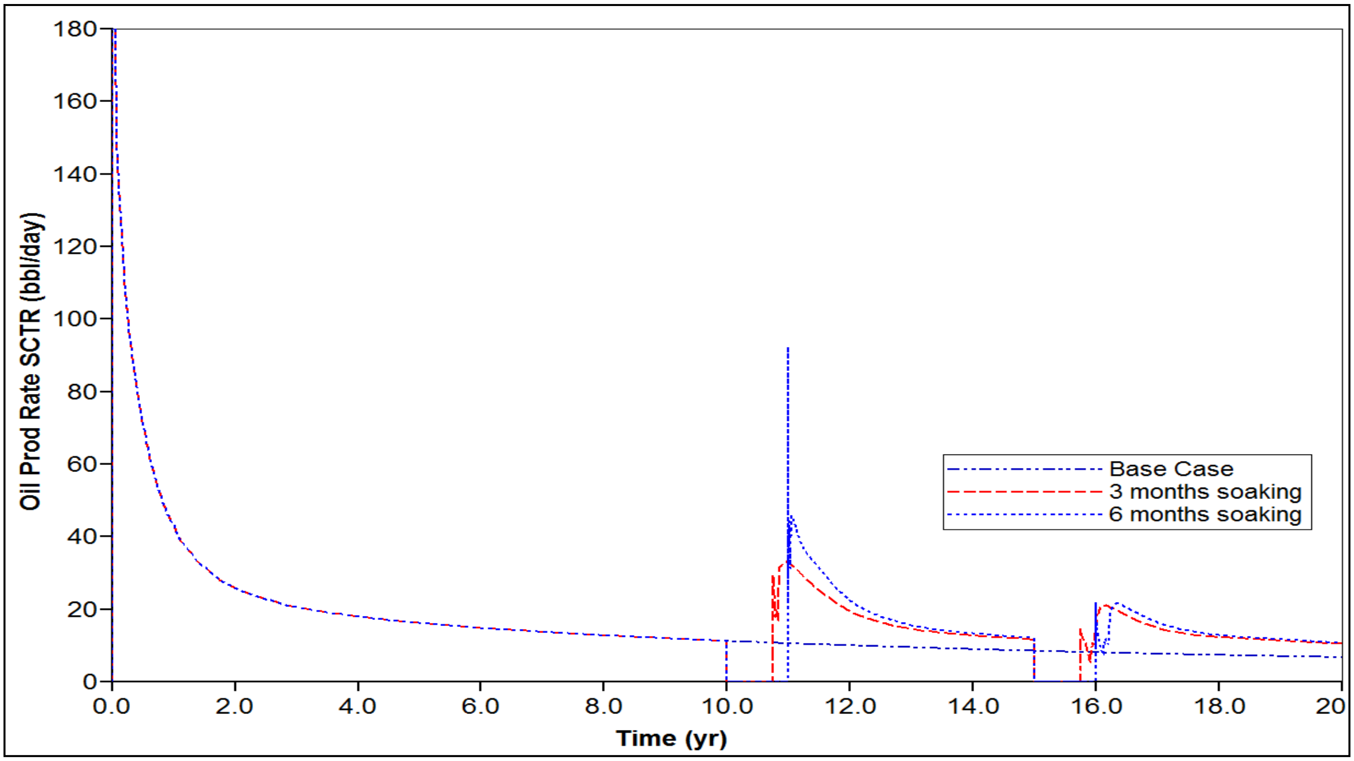
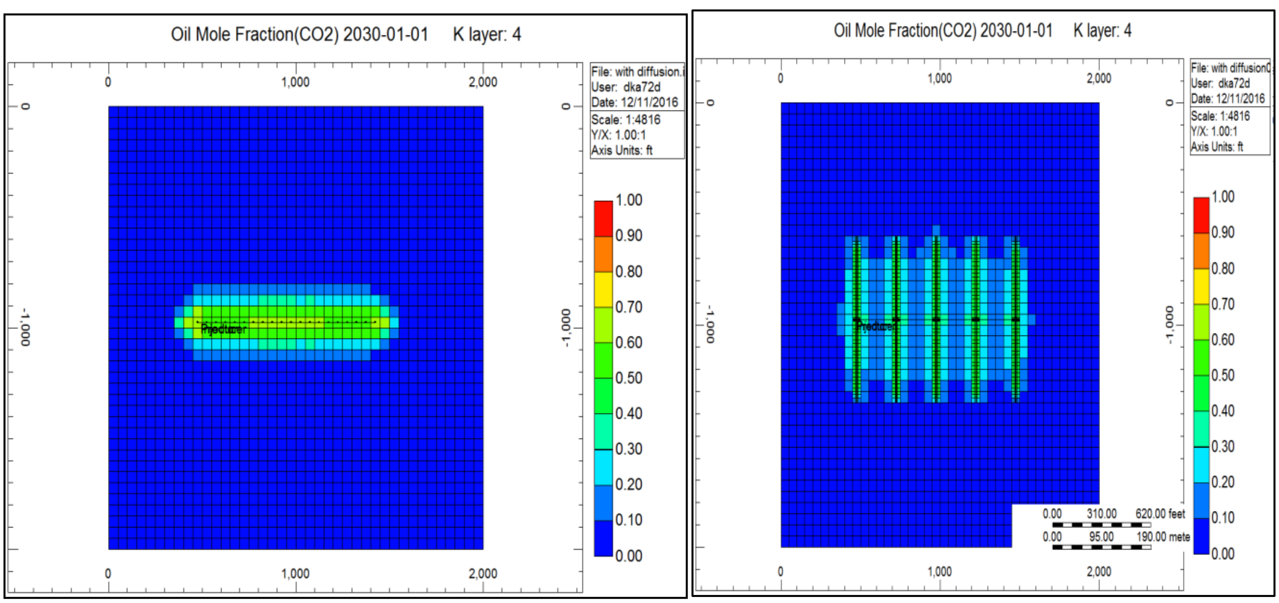
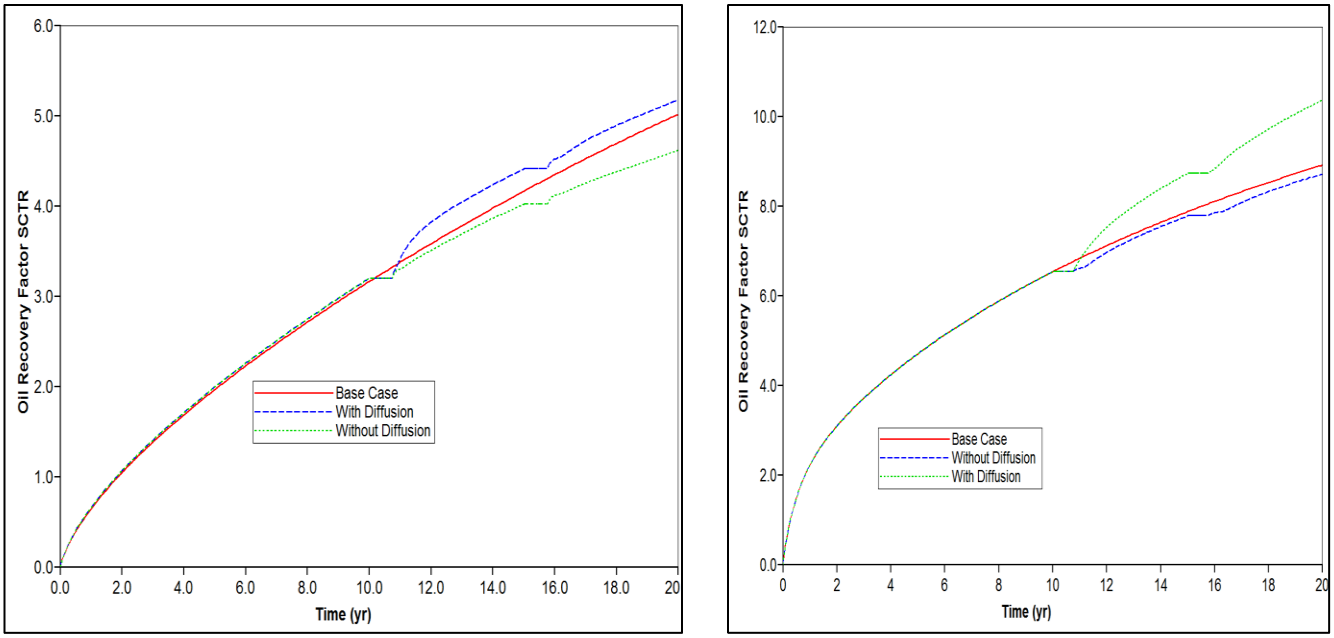


Fig. 12: Effect of soaking period on CO_2 huff-n-puff performance



a- Un-fractured well b- Fractured well

Fig. 13: Comparison between the penetration of the injected CO_2 in the fractured well versus the un-fractured well in Bakken model



a-Un-fractured well **b- Fractured well**

Fig. 14: Comparison between CO_2 performance in fractured well versus un-fractured well in Bakken

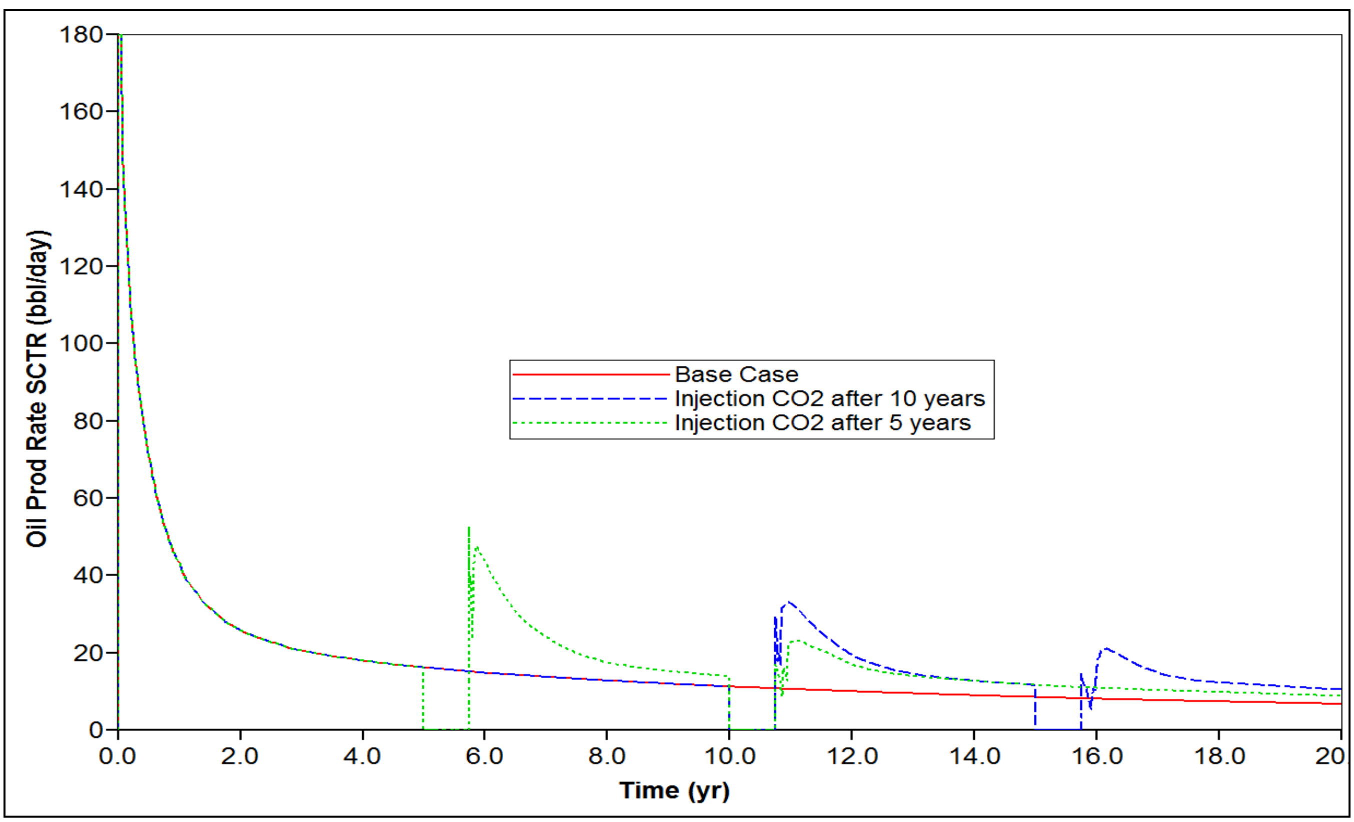


Fig. 15: Effect of the performing time on CO_2-EOR in shale oil reservoirs

Design of Experiments for the Factors Affecting the performance of CO_2-EOR in the huff-n-puff process

Sensitivity Analysis. The purpose of Sensitivity Analysis is for determining how sensitive an objective function to different parameters qualitatively and quantitively. Identifying the parameters which have a high impact on CO_2-EOR huff-n-puff performance would give a good prediction for the CO_2-EOR success or failure depending on the reservoir properties prior to the field application. In this part, the objective function which was used is the oil recovery factor at 10 years from CO_2-EOR huff-n-puff process. The parameters which were investigated and their range values are listed in **Table 9**. The statistical methods which were used for ranking these parameters are as the following:

- **Sobol Method**: The Sobol method is one of the variance-based sensitivity analysis methods to quantify the amount of variance that each input factor Xi contributes to the unconditional variance of output V(Y) (CMG)[7]. For example, a given case with 3 inputs and one output, if 50% of the output change would happen by changing the first input, 30% by changing the second input, 10% by changing the third one, and 10% due to interactions between the first two input parameters, these percentages are clearly reflected in measures of sensitivity. For more information about the basics and principles of this method, the reference of Sobol, (1992) can be reviewed [110].
- **Morris Method:** The Morris method (also named the Elementary Effects (EE) method) is one of the screening methods which is used to determine the effect of the input parameters on the model outputs (CMG)[7]. Morris approach has two measures, the Mean and the Standard Deviation, which are used together. The Mean reflects the linear influence of an input factor on the output function while the Standard Deviation reflects the nonlinear or interaction functionality. For more information about the basics and principles of this method, the reference of Morris, (1991) can be reviewed[109].
- **Tornado Plot:** a visual tool provides a qualitative and quantitative effect for the input parameters on the output ones, with a higher value meaning more sensitive to that parameter and vice versa (CMG)[7]. For more information about the basics and principles of this method, CMG reference number can be reviewed[7].

Rank of the High-Impact Parameters which control the performance of CO_2-EOR huff-n-puff process.

- **Formation total porosity (including natural fracture porosity):** Both of Sobol approach and Morris method indicated that the most important factor which affects the obtained oil recovery by CO_2-EOR is the total porosity of shale formation as shown in **Fig. 17A** and **Fig. 17B**. We concluded that as formation porosity and fracture intensity increase, oil recovery obtained by CO_2-EOR increases, which means that total porosity of the shale formation has a positive effect on CO_2-EOR performance as shown in **Fig. 16**. The interpretation which we think behind this behavior is that increasing the total porosity of formation would increase the contact area between the injected CO_2 and the formation oil, so CO_2-EOR performance would be enhanced.
- **Formation Average Permeability (counting for HF, NF, and matrix permeability):** Both of Sobol approach and Morris method indicated that the second parameter which controls the success of CO_2-EOR is the average conductivity of shale formation as shown **Fig. 17A** and **Fig. 17B**. We found that as the conductivity of oil pathways increased, oil recovery obtained by CO_2-EOR decreased, which means that the conductivity of oil-pathways has a negative effect on the CO_2-EOR performance as shown in **Fig. 17D**. The interpretation which we think behind this behavior is that increasing the conductivity of oil pathways in shale formations would result in increasing the kinetics of oil recovery process in the productive areas. As a result, for a limited effective diffusion rate for the injected-CO_2 into formation

oil, CO_2 would experience less exposure time with the formation oil before its being produced back. Therefore, CO_2-EOR performance would be downgraded with the increasing in oil-pathways conductivity.

- **Molecular Diffusion Rate:** Both of Sobol approach and Morris method indicated that the third parameter which controls the success of CO_2-EOR is the molecular diffusion rate between the injected CO_2 and the formation oil as shown in **Fig. 17A** and **Fig. 17B**. It is clear that as far as the molecular diffusion rate increased, the oil recovery obtained by the CO_2-EOR increased, which means that this parameter has a positive effect on the CO_2-EOR performance as shown in **Fig. 17D**. As far as the molecular diffusion rate increased, it would make CO_2 penetrate deeper into the tight matrix, far away from the hydraulic fractures. However, the case of CO_2 injection which has a low diffusion capacity makes the CO_2 penetrate just in the limited areas around the hydraulic fractures. Therefore, for the cases in which CO_2 penetrates deeper in the tight matrix, CO_2 would swell more volumes of oil, reduce oil viscosity, and finally produce larger quantities of oil by the counter-current mechanism. On the other hand, the cases in which CO_2 has a low molecular-diffusion rate would produce the injected-CO_2 back very soon.

Table 9: Parameters with their range which were used in the CMOST analysis

Parameters	**Range**
Total Porosity (%)	0.05-0.11
K in I-direction (mD)	0.005-0.011
K in J-direction (mD)	0.005-0.011
K in K-direction(mD)	0.005-0.011
Diffusion Rate (cm^2/sec)	0.0006-0.01
HF K in I-direction (mD)	1-10000
HF K in J-direction (mD)	1-10000
HF K in K-direction (mD)	1-10000

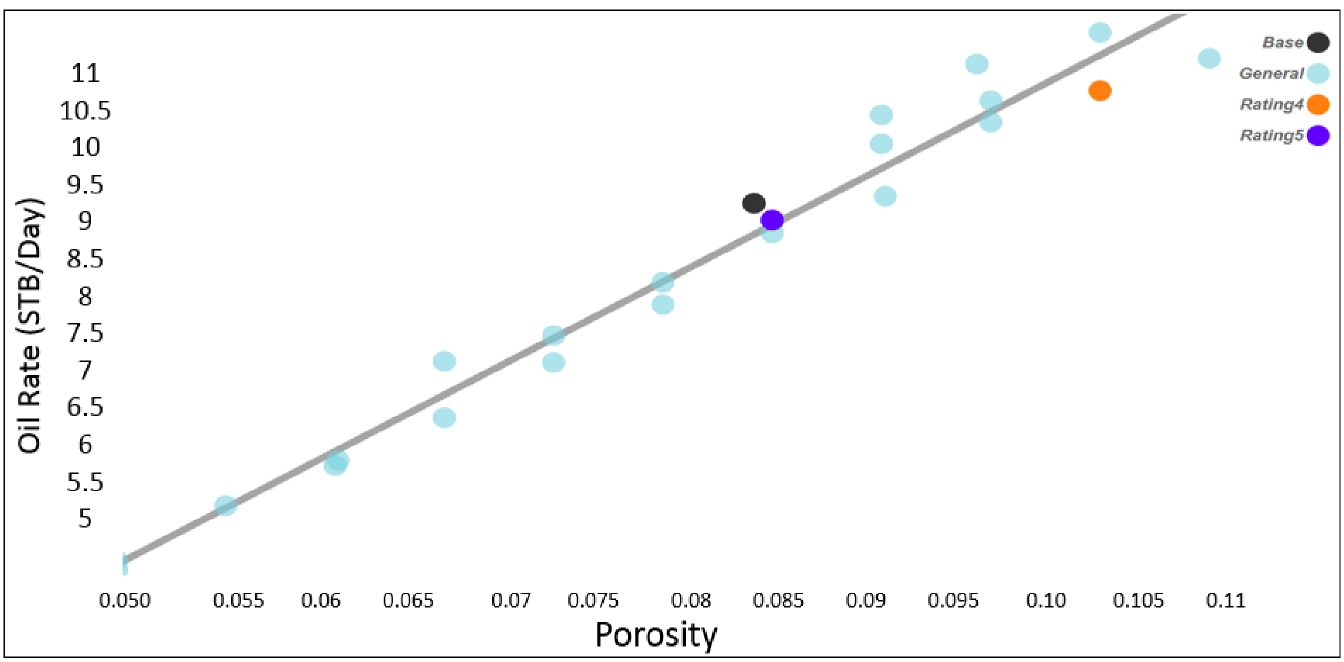
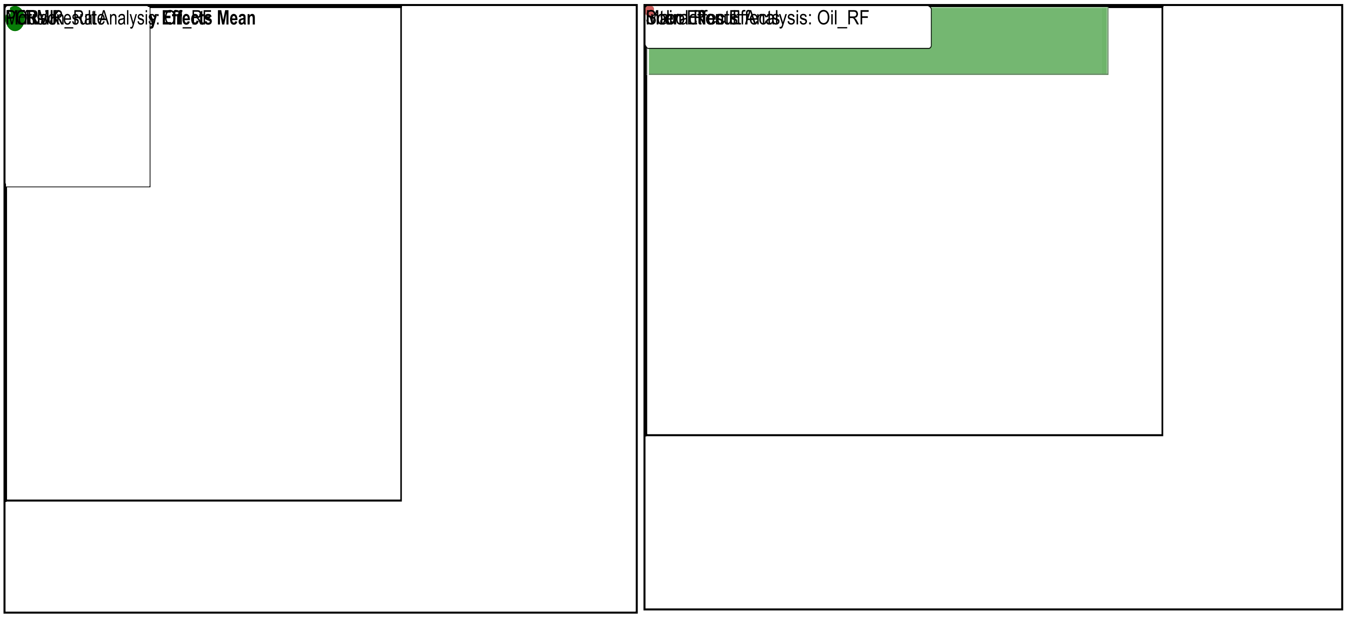
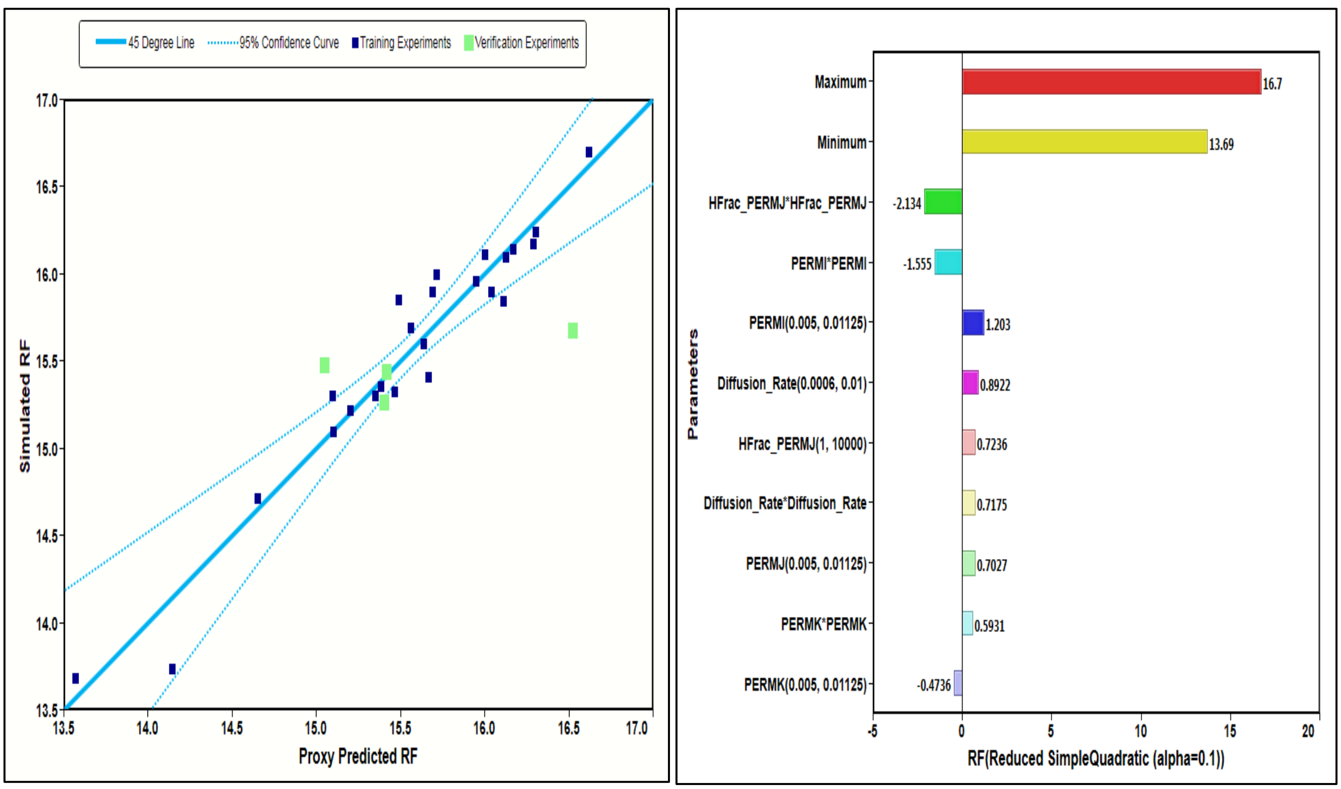


Fig.16: Effect of the porosity (Natural Fracture intensity) on oil production enhancement by CO_2-EOR huff-n-puff



A-Morris Method B-Sobol Method



C-Proxy Vs simulated model D-Tornado Plot

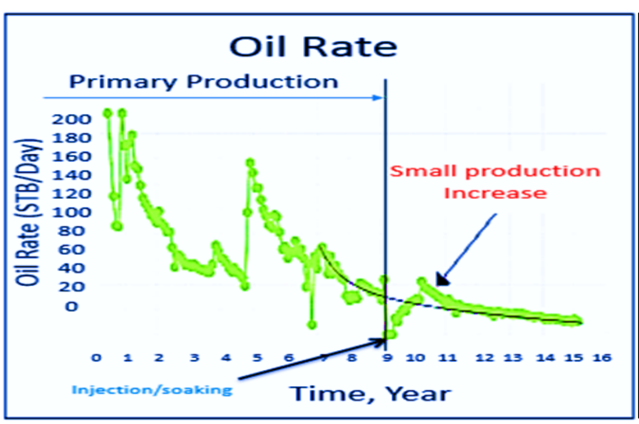
Fig.17: Design of Experiments for factors impacting CO_2-EOR huff-n-puff process

CO_2-Diffusivity Level in the Real Conditions for Shale Oil Reservoirs

We used the typical fluid and rock properties of Bakken to build a model for the Pilot test#2 which have been reported in Hoffman et al., (2016) paper and it was previously explained in this paper. Different scenarios have been run until the best match obtained between the well model and the pilot test as shown in **Fig. 18.** Everything was identical between the model results and pilot tests results which are shown in **Fig. 18**. However, there is just one difference. This difference is that the oil production came quickly after the soaking period in the pilot test; however, it takes longer time in the model case. We believe this is happening due to the reported conformance problems in these pilots where CO_2 produced in the offset wells. Therefore, the produced-back CO_2 volumes during puff process were small which resulted in less hold up effect on the produced-oil. However, in our model, we did not induce injection fractures. Therefore, CO_2 in large volumes produced back during the puff process of our model.

Among different scenario which we investigate, we found that this match can be obtained in a dual permeability model with a low CO_2 diffusivity. This means that either of the diffusion rates for the injected CO_2, in the reservoir conditions, is too low or the kinetics of the oil recovery process in the production areas are fast. The first possibility which is the low-diffusivity for the injected CO_2 in shale reservoirs conditions can be explained by two ways: (1) The contact area between the injected CO_2 and the formation oil is small, (2) The exposure time between the injected CO_2 and the formation oil is short. The contact area between CO_2 and the formation oil is a function of the natural-fractures intensity in shale oil reservoirs. Although it has been reported that these types of reservoirs have a high intensity of natural fractures, the dual permeability model can match the conducted pilot test results with a low intensity of natural fractures. This indicated that either of these natural fractures is not active or they are not connected in good pathways with the hydraulic fractures.

Most of the previous experimental studies reported that CO_2 diffusion mechanism is beyond the increment in the oil recovery obtained in the lab conditions. This increment in the oil recovery and/or the diffusion rate which was observed in the lab conditions was directly upscaled by most of the previous researchers to the field scale via numerical simulation methods. This direct upscaling methodology is so optimistic because the lab-cores have a higher contact area and a longer exposure time to the injected CO_2 than what happens in these reservoirs conditions. Therefore, both of the previous simulation studies and the experimental reports were optimistic to predict a quick improvement in the oil recovery from injecting CO_2 in these unconventional reservoirs. This might explain why the results from the CO_2 pilot tests are disappointing. To sum up, the diffusion mechanism for the injected CO_2 in the pilot tests had not been well recognized because either of the kinetics for the oil recovery process in the productive areas of these reservoirs are too fast or the CO_2 diffusion rate in the field conditions is too slow. According to this study, what happened in the field scale and what should be done is summarized in **Fig. 19**.



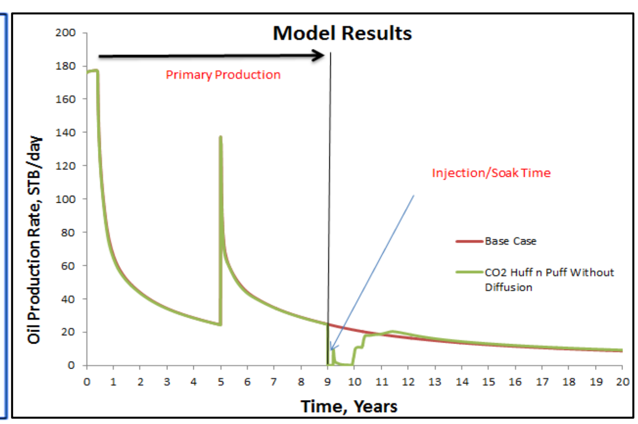


Fig. 18A: CO_2 Pilot test#2 (Hoffman et al., 2016)

Fig. 18B: History match from the simulated model

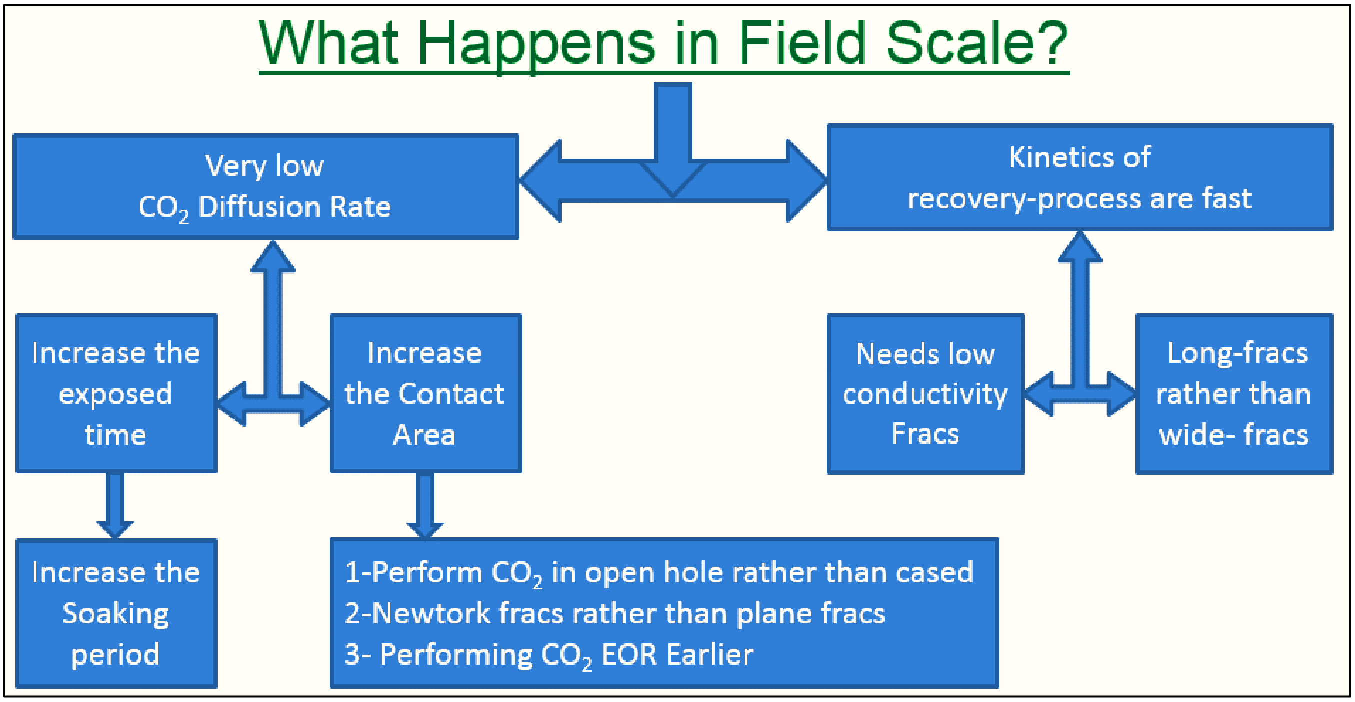


Fig. 19: What happens at the field scale and what should be done according to this study

Conclusions

- From this study, some general guidelines have been provided to understand the CO_2-EOR performance in the field scale of unconventional reservoirs in North America.
- Three different approaches which are lab reports, numerical simulations, and pilot tests have been combined and compared in this study for getting an integrated picture about CO_2 mechanisms in shale oil reservoirs.
- Design of Experiments approved that the natural fracture intensity and oil-pathways conductivity are the two main factors which control CO_2-EOR success in shale oil reservoirs. However, the fractures intensity has a positive effect on CO_2-EOR while the later has a negative effect.
- The performing time for CO_2-EOR has a significant effect on the CO_2 huff-n-puff success.
- Molecular diffusion mechanism is the critical key for CO_2-EOR success in shale oil reservoirs. However, the direct upscaling for this mechanism to the field scale via conventional simulation methods by using the same lab-obtained CO_2-diffusion rates is misleading.
- To be significant in the field scale, this mechanism requires having either of kinetics for the oil recovery process in the productive areas of these reservoirs are too slow or CO_2 diffusion rates in field conditions are too fast.
- The history match with some of the reported pilot-tests indicated that the kinetics of oil recovery process in the productive areas are faster than the diffusion rates for the injected CO_2 in those poor-quality reservoirs.

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