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Simulation Study of CO_2 Injection in Tight Oil Reservoirs

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Research Article

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Abstract

The exploitation of Tight oil reservoirs has become a topic of interest to many searchers; the choice of methods and techniques to use, depending on the characteristics of the fluids in place is the main focused point for this purpose. Tight oil formation is formation with an ultra-low permeability (less than 0.1 mD); Horizontal well and hydraulic fracturing were identified by many searchers as the main methods to exploit this kind of reservoir. However, some new knowledge about the improvement of the oil recovery helped us to understand that there is still a lot of remaining oil in the reservoir after applying these methods: we chose CO_2 huff-n-puff process to enhance the oil recovery. In this paper, we used The Bakken oil formation study as our base case. Our work is focused on parameters that can improve oil recovery without spending a high cost. We noticed that some parameters such as reservoir permeability, number of fracture per stage, CO_2 injection rate, number of CO_2 huff-n-puff cycle, CO_2 injection time and fracture permeability can be key parameters for the improvement of the oil recovery.

Keywords: Tight oil reservoirs; CO2 injection; Hydraulic fracturing; Simulation model

Introduction

The Bakken formation with multiple oil-bearing layers is one of major productive tight oil reservoirs in North America [1], where Middle Bakken and Three Forks are the two primary layers for oil production since they have the best reservoir qualities such as porosity and oil saturation [2]. Figure 1 presents the location map of the Williston Basin with structure contours [3]. It has been reported that the Middle Bakken has an estimated average oil resource of 3.65 billion barrels and Three Forks has an estimated average resource of 3.73 billion barrels [4]. The combination of two technologies (horizontal well and hydraulic fracturing) has been considered as the best way to produce this kind of formation. During hydraulic fracturing, a total of about 182,500 bbl of fluid and 2,555,000 lbs of proppant are pumped for each well in the Middle Bakken and 153,000 bbl of fluid and 2,454,000 lbs of proppant for each well in the Three Forks [5]. The main goal of proppant is to keep the created hydraulic fractures open with enough fracture conductivity. There are many proppant types used in the Bakken formation, such as sand, ceramic, resin-coated sand or their combinations [6]. Ceramic proppant can provide not only a higher fracture conductivity but also a greater longevity and durability than sand or resin-coated sand [7]. In this paper, CO_2 huff-n-puff injection has been chosen as an enhanced oil recovery method for the Bakken formation; this process consists of three stages such as CO_2 injection, CO_2 soaking, and production, as shown in Figure 2. During the early soaking period, injected gas penetrates into the rock matrix and repressurizes the limited area around the fracture network and depleted area [8].

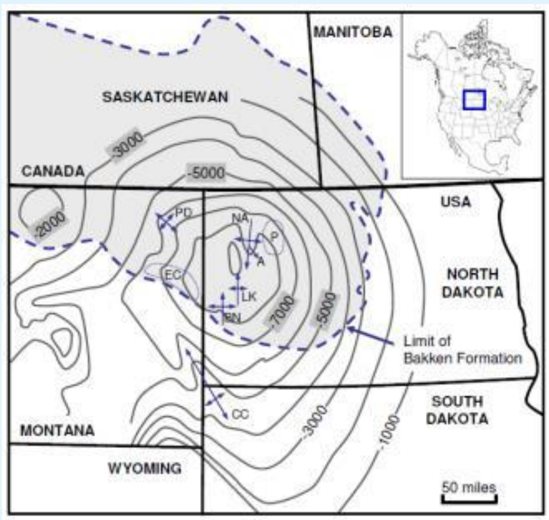


Figure 1: Location map of the Williston Basin with structure contours [3].

The CO_2 injection in tight oil reservoirs is defined as the following conceptual steps: CO_2 first flows into and through the fractures; then it diffuses into the matrix and oil moves out of pores through swelling and reduced viscosity; finally, the oil will be driven into the fractures and the wellbore with the CO_2 pressure gradient [9]. From the literature review Arshad A, Al-Majed A, Maneouar H, [10], it has been shown that CO_2 injection can be injected as immiscible or miscible flooding but immiscible flooding is less effective than miscible flooding. The miscibility development between CO_2 and the crude oil at the reservoir conditions of pressure and temperature is a key factor affecting the recovery; it has a strong effect on the microscopic efficiency which is directly related to the recovery factor. Two kinds of miscibility can occur; first contact miscibility and multiple contact miscibility. First contact miscibility happens when a single phase is formed when CO_2 is mixed with the crude oil [10]. Multiple contact miscibility occurs when miscible conditions are developed in situ, through composition alteration of the CO_2 or crude oil as CO_2 moves through the reservoir [10]. It can be achieved at pressures above the minimum miscibility pressure (MMP). MMP is the pressure at which the reservoir fluid develops miscibility with CO_2 and is a very important parameter in a well-designed CO_2 flooding project.

A numerical reservoir simulation was also studied with a 20 ft × 20 ft × 10 ft Grid cells dimension. CMG-GEM, 2017 was used as an appropriate simulator to model multiple hydraulic fractures and fluid flow in tight oil reservoirs. A sensitivity study helped us to understand that some parameters can affect oil recovery.

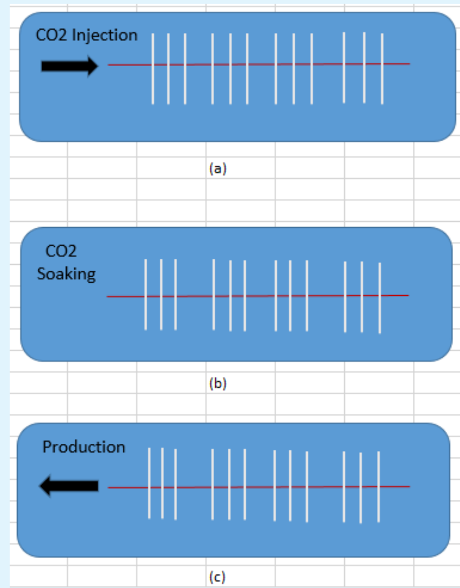


Figure 2: The CO_2 huff-n-puff process in a horizontal well with multiple fractures. (a) Stage 1: CO_2 injection. (b) Stage 2: CO_2 soaking. (c) Stage 3: production.

Mathematical Formulation

As it is a compositional model, the masse conservation equation for component i becomes:

$$-\nabla.\left[\alpha\left(c_{ig}\rho_g v_g + c_{il}\rho_l v_l\right)\right] + \alpha q_i = \alpha\frac{\partial}{\partial t}\left[\alpha\left(c_{ig}\rho_g v_g + c_{il}\rho_l v_l\right)\right]$$

where α is the geometric factor; c_{ig} the mass fraction of component i in the gas phase; c_{il} the mass fraction of component i in the liquid phase l; ρ_g the gas density and ρ_l the liquid density.

Introducing Darcy's law for each phase $\mu_f = -\dfrac{kk_{rf}}{v_f}$

$$\nabla.\left[\frac{\alpha c_{ig}\rho_g k k_{rg}}{\mu_g}\left(\nabla\rho_g-\rho_g g\nabla D\right)\right]+\left[\frac{\alpha c_{il}\rho_l k k_{rl}}{\mu_l}\left(\nabla\rho_l-\rho_l g\nabla D\right)\right]+\alpha q_i=\alpha\frac{\partial}{\partial t}\left[\left(\alpha c_{ig}\rho_g v_g+\alpha c_{il}\rho_l v_l\right)\right]$$ i=1,2…N

Some equations must be considered to resolve the previous equation.

$$\sum_{k=1}^{n} c_{ig}=1 \quad \frac{c_{ig}}{c_{io}}=k_{igo}$$

$$\sum_{k=1}^{n} c_{io}=1 \quad \frac{c_{ig}}{c_{iw}}=k_{igw}$$

$$\sum_{k=1}^{n} c_{iw}=1$$

$$So + Sw + Sg = 1$$
$$Pcow = Po - Pw$$
$$Pcgo = Pg - Po$$

Reservoir Characteristics and Numerical Simulation Model

Reservoir Description

A tight oil reservoir of 20 ft × 20 ft × 10 ft Grid cells dimension was built. The average matrix permeability of the reservoir is 0.7 $\times 10^{-2}$ mD and average porosity 5.6 %. The average thickness of the reservoir is 5ft. Formation oil density is 600 kg/m^3 and formation oil viscosity is 1.2 mPa.s. The GOR is 60.21 m^3/m^3. The formation pressure is 12 MPa and the crude oil volume factor is 1.127. Figure 3 presents the reservoir model including 4 fracturing stages for the Bakken tight oil reservoir. Three effective fractures per stage.

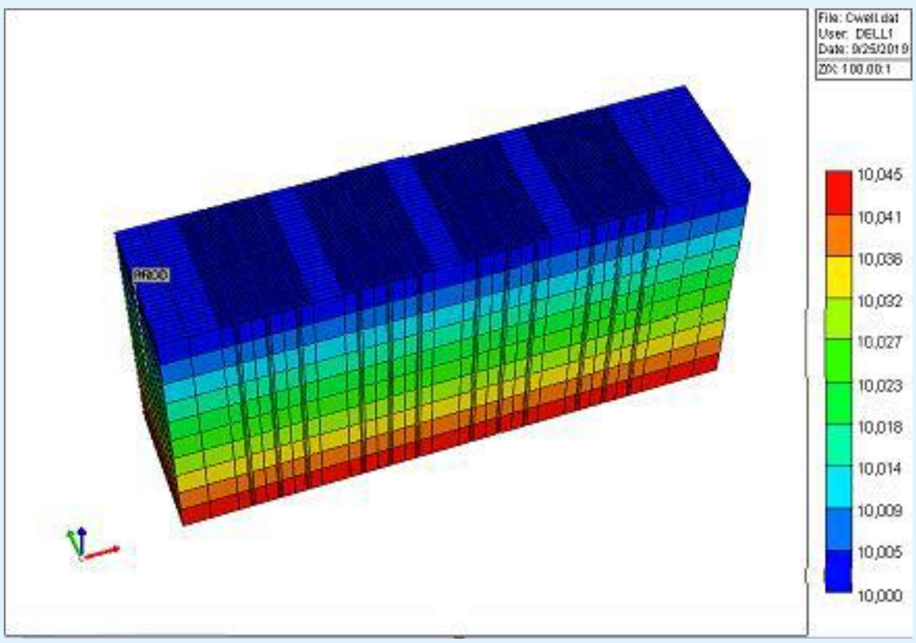


Figure 3: 3D reservoir model including 4 fracturing stages for Bakken tight oil reservoir. Three effective fractures per stage.

The bottom hole pressure curve obtained during history matching is presented in Figure 4. The results from history matching for oil and gas are presented in Figure 5 and Figure 6 respectively. It can be seen that there is a reasonable match between the actual field data and numerical simulation results. The main tuning parameters during history matching are listed in Table 1. Furthermore, some relative permeability curves such as water-oil relative permeability and liquid-gas relative permeability were obtained by tuning them to fit a good history matching as shown in Figure 7.

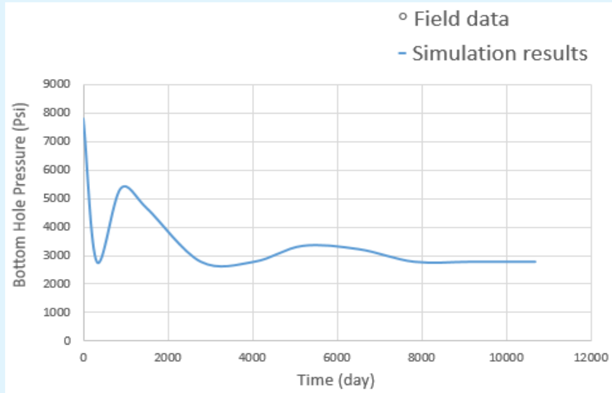


Figure 4: Bottom hole pressure input for history matching.

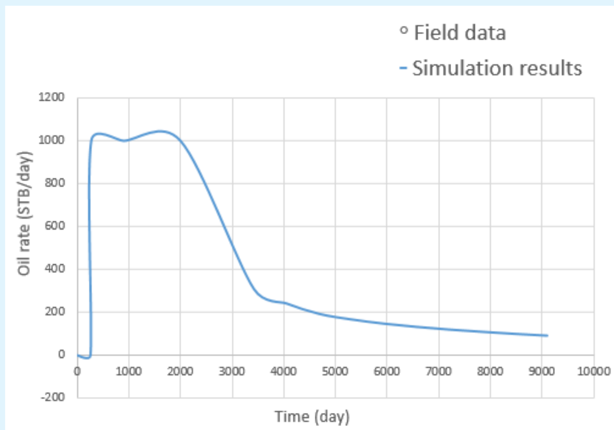


Figure 5: History matching for Oil flow rate.

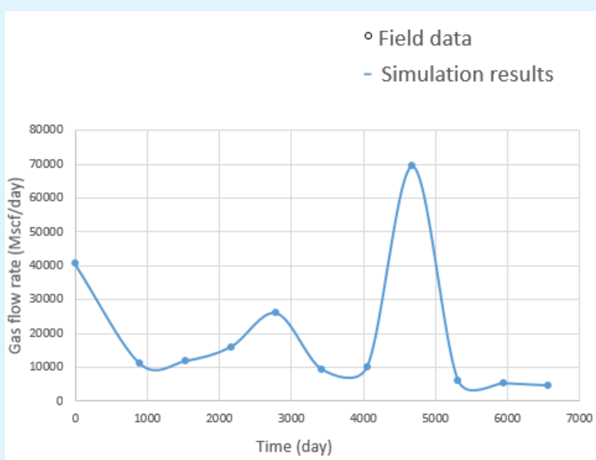
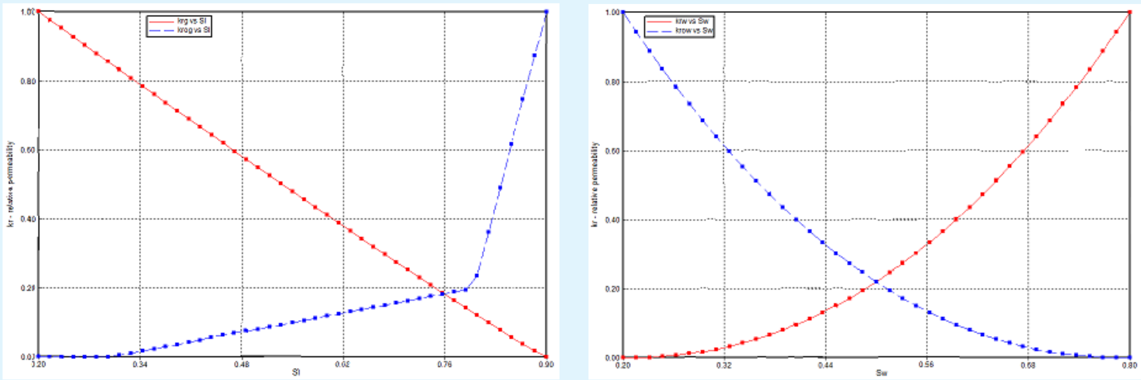


Figure 6: History matching for Gas flow rate.



Water-oil relative permeability curve Liquid-gas relative permeability curve
Figure 7: Relative permeability curves for a good history matching.

Parameter	Value	Unit
The model dimensions	10500 ×2640 ×50	ft
Initial reservoir temperature	7800	Psi
Production time	1.2	Year
Reservoir temperature	245	°F
Initial water saturation	0.41	Value
Total compressibility	1 × 10−6	*psi*−1
Matrix permeability	5	µD
Matrix porosity	0.056	Value
Horizontal well length	8828	ft
Number of stages	15	Value
Total number of fractures	60	Value
Fracture conductivity	50	mD-ft
Fracture half-length	215	ft
Fracture height	50	ft

Table 1: Parameters used for history matching (Bakken formation).

Numerical Simulation Model

Based on a tight oil reservoir, a simulation model of CO_2 huff-n-puff process in a horizontal well with multi-stage fractures is built. In this work, we first of all started by producing for four years and then the horizontal well is converted to CO_2 injector with injection rates of 100 MSCF/day. After six months of injection, the well is shut-in and soaking for three months. Finally, the well is put back in production for one year. This represents one cycle of CO_2 huff-n-puff. The cycle will start again at the end of the year of production and will cover the 30 years.

Many cases are studied in this simulation to investigate the sensitivity study. For the base case, we set up one fracture per stage for a total of 4 stages. For each stage fracture width is 0.03 ft, fracture half-length is 1300 ft, fracture height is 40 ft and fracture conductivity is 6.9 md-ft. To study the sensitivity of the CO2 huff-n-puff process, other cases were applied. The second case is built by inputting two; three fractures per stage. The third case is built by varying CO2 injection rates (50, 100, 500) ''Mscf/day''. The fourth case is built by varying CO2 injection time (3, 6, 9) ''Month''. The fifth case was built by varying the total number of cycles (3, 10, 17). The sixth case was built by varying soaking time (3, 5, 6) ''Month''. The seventh case was built by varying the fracture permeability (230, 500, 800) ''mD''. The eighth case was built by varying the fracture half-length (650, 1300, 2000) ''ft''. The ninth case was built by varying the reservoir permeability (0.003, 0.007, 0.01) ''mD''. Table 2 lists the fluids properties used for the simulation study. The reservoir oil composition is constituted by seven different pseudo components, i.e. CO_2, $N_2–C_1$, $C_1–C_4$, $C_5–C_7$, $C_8–C_{12}$,

C_{13}–C_{19}, C_{20}–C_{30}, and their corresponding molar fractions are 0.01%, 22.03%, 11.67%, 28.15%, 9.4% and 8.08%, respectively**.** Table 3 presents the order detailed input data required for the Peng-Robinson equation-of-state (CMG-WinProp, 2017).

Parameter	Value	Unit
The model dimensions	20 ×20 ×10	ft
Initial reservoir temperature	7800	Psi
Production time	30	Year
Reservoir temperature	240	°F
Initial water saturation	0.2	Value
Total compressibility	$1 \times 10{-}6$	$psi{-}1$
Matrix permeability	0.007	µD
Matrix porosity	0.056	Value
Horizontal well length	8828	ft
Number of stages	4	Value
Total number of fractures	12	Value
Fracture conductivity	6.9	mD-ft
Fracture half-length	1300	ft
Fracture height	10	ft

Table 2: Parameters used for the CO_2 huff-n-puff process.

Component	Molar Fracture	Critical Pressure (atm)	Critical Temperature (k)	Critical Volume (L/mol)	Molar Weight (g/mol)	Acentric Factor
CO_2	0.0001	72.8	304.2	0.094	44.01	0.225
$N2$-$C1$	0.2203	45.24	189.67	0.0989	16.21	0.0084
$C1$-$C4$	0.2063	43.49	412.47	0.2039	44.79	0.1481
$C5$-$C7$	0.117	37.69	556.92	0.3324	83.46	0.2486
$C8$-$C12$	0.2815	31.04	667.52	0.4559	120.52	0.3279
$C13$- $C19$	0.094	19.29	673.76	7649	220.34	0.5672
$C20$-$C30$	0.0808	15.38	792.4	1.2521	321.52	0.9422

Table 3: Compositional data for the Peng-Robinson EOS in Bakken.

Results and Discussions

As mentioned above, eight uncertain parameters (as listed in Table 4) were studied to analyze the sensitivity of CO_2 huff-n-puff process in the Bakken tight oil. The effect of each parameter on the oil recovery was also identified. The pressure distribution at 30 months of the field production for the best case is presented in Figure 8.

Parameter	Value 2	Base case	Value 3
Number of fracture	1	2	3
CO_2 injection rate, Mscf/day	50	100	500
CO_2 injection time, month	3	6	9
Number of cycle	3	17	10
CO_2 soaking time, month	5	3	6
Fracture permeability, mD	500	230	800
Fracture half-length, ft	650	1300	2000
Reservoir permeability, mD	0.003	0.007	0.01

Table 4: Eight parameters used for sensitivity study.

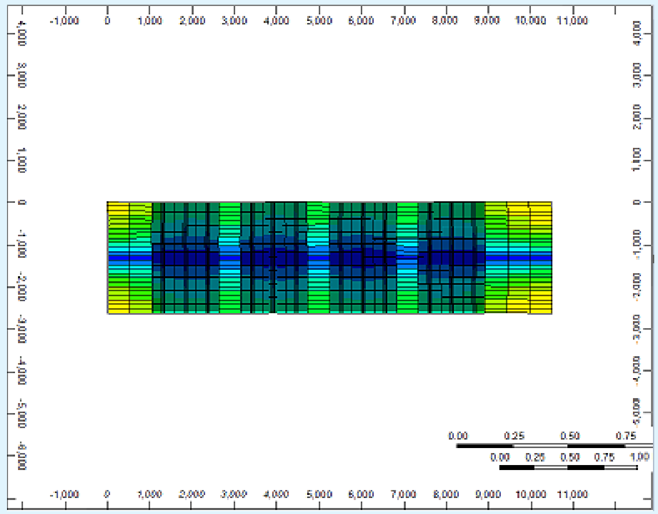


Figure 8: Pressure distribution at 30 months for the best case.

Effect of Number of Fracture per Stage on Oil Recovery Factor

For this case, we successively set up 1, 2, and 3 fractures per stage; while keeping the other parameters the same as those in the base case. We obtained an oil recovery factor of 8.3%, 8.56%, and 8.67% respectively as shown in Figure 9. It can be seen that the oil recovery increases with an increase of the number of fracture per stage.

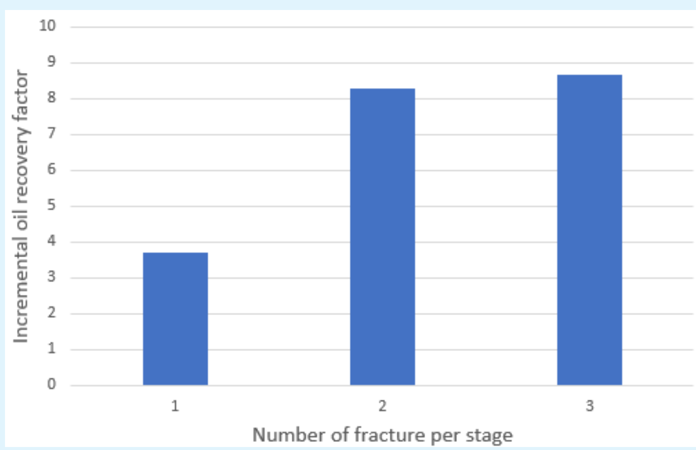


Figure 9: Comparison of incremental oil recovery factor for the three cases.

Effect of CO_2 Injection Rate on oil Recovery Factor

For this case, we successively set up CO_2 injection rate to be 50 Mscf/day, 100 Mscf/day, and 500 Mscf/day; while keeping the other parameters the same as those in the base case. We obtained an oil recovery factor of 2.56%, 8.3%, and 8.6% respectively as shown in Figure 10. It can be seen that the oil recovery increases with an increase of CO_2 injection rate.

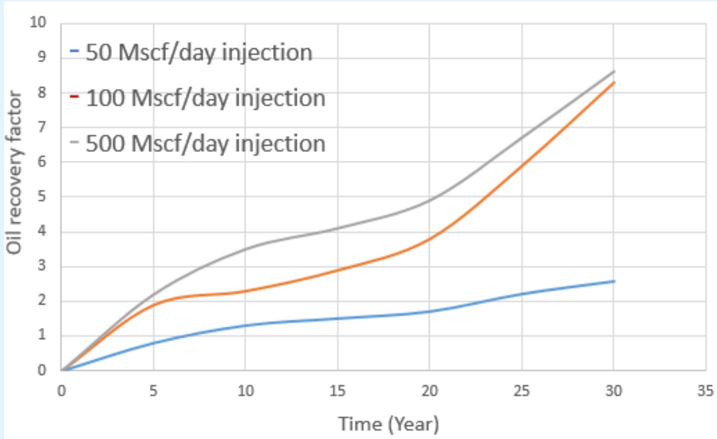


Figure 10: Effect of CO_2 injection rate on oil recovery factor.

We can observe that the oil recovery doesn't increase a lot when we use a CO_2 injection rate of 500 Mscf/day. We conclude that it is economical to use 100 Mscf/day knowing that we will get almost the same result.

Effect of CO_2 Injection Time on Oil Recovery Factor

For this case, we successively set up CO_2 injection time to be 3 months, 6 months, and 9 months; while keeping the other parameters the same as those in the base case. We obtained an oil recovery factor of 8.5%, 8.67%, and 8.97% respectively as shown in Figure 11. It can be seen that the increase of CO_2 injection time increases the oil recovery.

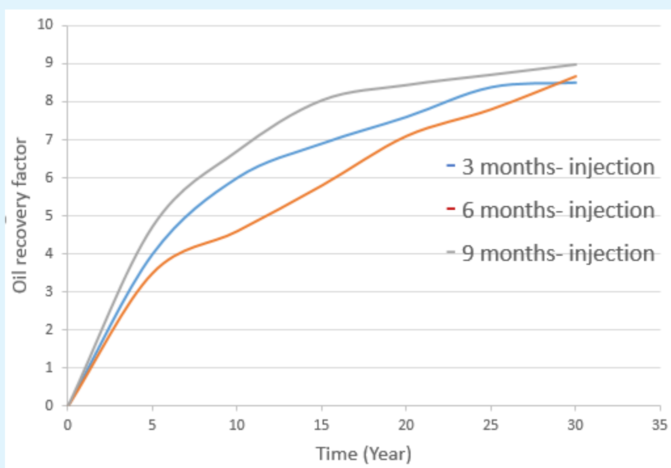


Figure 11: Effect of CO_2 injection time on oil recovery factor.

Effect of Number of CO_2 Huff-N-Puff Cycle on Oil Recovery Factor

For this case, we successively set up the number of cycle to be 3, 10, and 17; while keeping the other parameters the same as those in the base case. We obtained an oil recovery factor of 5.43%, 7.9%, and 8.67% respectively as shown in Figure 12. It can be seen that the oil recovery increases with the increase of the number of CO_2 huff-n-puff cycle.

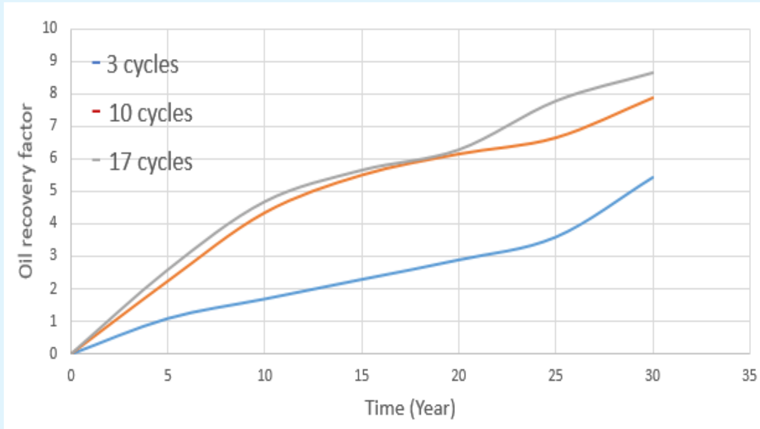


Figure 12: Effect of number of cycle on oil recovery factor.

Effect of CO_2 Soaking Time on Oil Recovery Factor

For this case, we successively set up CO_2 soaking time to be 3 months, 5 months, and 6 months; while keeping the other parameters the same as those in the base case. We obtained an oil recovery factor of 8.67%, 8.87%, and 8.93% respectively as shown in Figure 13. It can be seen that the oil recovery increases with the increase of the soaking time.

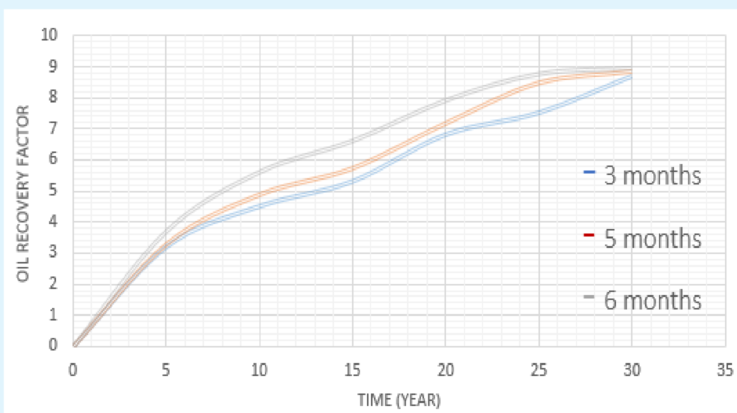


Figure 13: Effect of soaking time on oil recovery factor.

Effect of Fracture Permeability on Oil Recovery Factor

For this case, we successively set up the fracture permeability to be 230 mD, 500 mD, and 800 mD; while keeping the other parameters the same as those in the base case. We obtained an oil recovery factor of 8.67%, 8.87%, and 8.97% respectively as shown in Figure 14. It can be seen that the oil recovery increases with the increase of the fracture permeability.

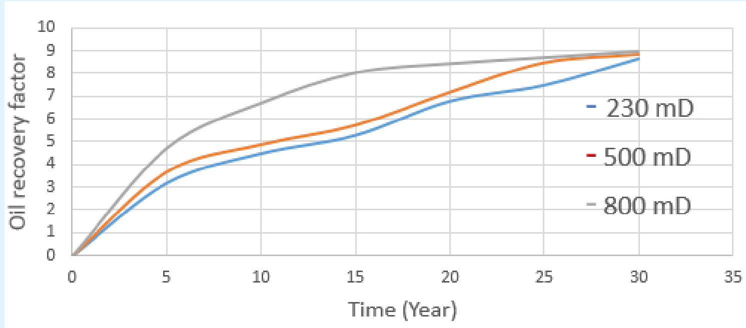


Figure 14: Effect of fracture permeability on oil recovery factor.

By combining Darcy's law and Poiseuille's law we get an equation that can help us to analyze the effect of fracture permeability on the oil flow rate, then on the recovery.

Darcy's law: $q_D = \frac{AK\Delta P}{\mu L}$ (1)

Poiseuille's law: $q_p = \frac{we^3\Delta p}{12\mu L}$ (2)

Combining 1 and 2 we get $\frac{AK\Delta P}{\mu L} = \frac{we^3\Delta p}{12\mu L}$

K= $\frac{we^3}{12A}$ k is the intrinsic fracture permeability.

From the equations we can deduce that the flow rate increases with the increase of fracture permeability; that is why this parameter is really important when studying CO_2 injection in tight oil reservoirs.

Effect of Fracture Half-Length on Oil Recovery Factor

For this case, we successively set up the fracture half-length to be 650 ft, 1300 ft, and 2000 ft; while keeping the other parameters the same as those in the base case. We obtained an oil recovery factor of 8.5%, 8.67%, and 8.7% respectively as shown in Figure 15. It can be seen that the oil recovery increases with the increase of the fracture half-length.

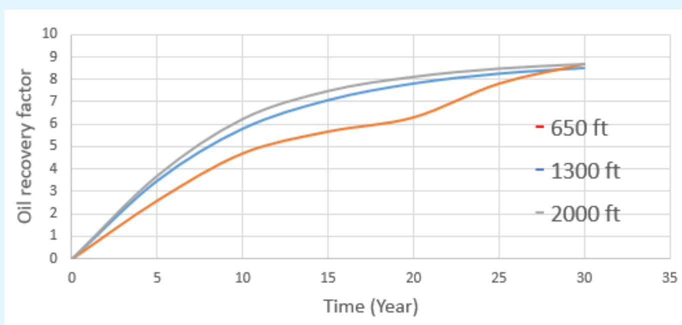


Figure 15: Effect of fracture half-length on oil recovery factor.

Effect of Reservoir Permeability on Oil Recovery Factor

For this case, we successively set up the reservoir permeability to be 0.003 mD, 0.007 mD, and 0.01 mD; while keeping the other parameters the same as those in the base case. We obtained an oil recovery factor of 7.9%, 8.67%, and 8.86% respectively as shown in Figure 16. It can be seen that the oil recovery increases with the increase of reservoir permeability.

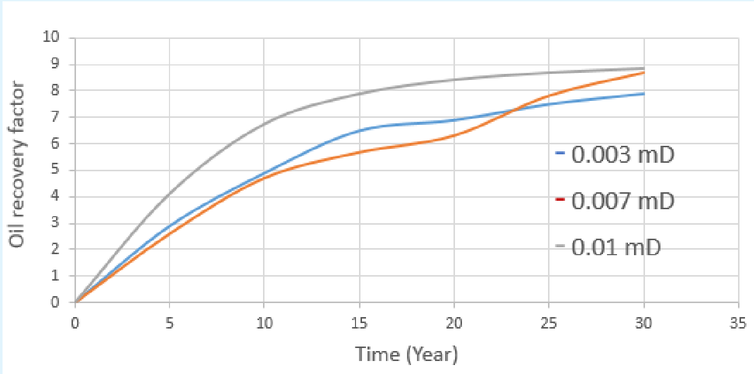


Figure 16: Effect of reservoir permeability on oil recovery factor.

Summary and Conclusions

After performing a series of simulations for the CO_2 huff-n-puff process for enhanced oil recovery in the Bakken formation, the following conclusions can be drawn:

1. The relative permeability curves, such as water-oil relative permeability and liquid-gas relative permeability are obtained based on history matching with a fractured well from the Middle Bakken.
2. The case with three effective hydraulic fractures within one perforation stage has the highest incremental oil recovery factor compared to the other cases with one and two fractures within one perforation stage.
3. A comparison of the oil recovery factor with and without gas injection has proved that it is higher when injecting gas (Figure 17).
4. CO_2 molecular diffusivity is a significant factor in the reservoir simulation model to capture the real physics mechanism during CO_2 injection into the tight oil reservoirs
5. Oil recovery factor increases with the increasing number of cycle of CO_2 huff-n-puff, number of fracture per stage, CO_2 injection time, CO_2 injection rate, CO_2 soaking time, fracture permeability; fracture conductivity and reservoir permeability.
6. The range for the incremental oil recovery factor at 30 years of production is obtained as 2.56% - 8.97%.

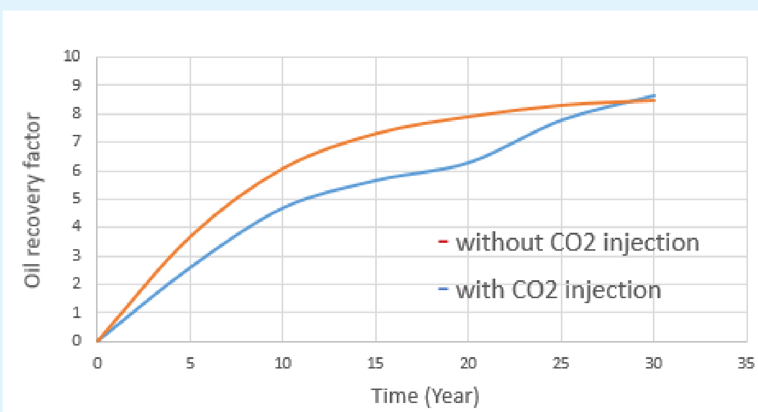


Figure 17: Comparison of oil recovery factor with and without CO_2 injection based on the case of three fractures per stage.

Acknowledgment

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Nomenclature

Nomenclature
bbl = barrels
MMP = Minimum miscibility pressure, psi
CMG = Computer Modeling Group
GOR = Gas oil ratio
Mscf = 103 standard cubic feet, $ft3$
mD = 103 Darcy

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