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Full Length Article

Simulation-based enhanced oil recovery predictions from wettability alteration in the Middle Bakken tight reservoir with hydraulic fractures

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ABSTRACT

Surfactant enhanced oil recovery is promising in tight formations by altering the wettability, reducing the interfacial tension, and promoting the counter-current imbibition process. In this paper, surfactant Huff-n-Puff in Bakken tight reservoir was studied based on modelling and simulation of a Middle Bakken well using actual field data. The effects of wettability alteration and interfacial reduction by surfactant solution were modeled based on laboratory data. The Embedded Discrete Fracture Model (EDFM) method was used to efficiently handle hydraulic fractures in the model in a fast way using non-neighboring connections as a new technique in this simulation study. We used a sector model with the EDFM method to conduct the surfactant Huff-n-Puff sensitivity simulation after the grid size optimization. We considered six sensitivity factors and each simulation case was conducted after history matching. Based on the simulation results, we found that the number of Huff-n-Puff cycles and the surfactant concentration are the most important factors, followed by surfactant adsorption, soaking time, injection time and injection rate. The percentage of oil recovery increase over the primary oil recovery ranges from 1.1% to 25.2%. This study can provide critical insights of key parameters affecting the surfactant flooding efficiency in Middle Bakken tight oil reservoir.

1. Introduction

The extraction of tight oil has become the focus of research with the development of horizontal well technology and the progress of multistage hydraulic fracturing in the United States. The Bakken Formation is one of the largest tight oil reservoirs in the U.S., which is typically characterized by low porosity (< 10%) and low permeability (< 0.1 mD) [9]. The Bakken is among the most significant oil discoveries in the United States in the past 40 years and has made North Dakota the second-highest oil-producing state in the U.S. [13]. In 2008, the reported technically recoverable oil reached 3.65 billion barrels [24]. This number increased to 11.43 billion barrels in 2013 [14], and 92 billion barrels in 2015 [15]. Moreover, the average daily oil production growth increased from 175 bbl/day in 1953 to 11,06836 bbl/day in [12]. However, the high oil production rate does not mean a high oil recovery factor. The ultimate recovery factor is still around 7% [27], which is far lower than the oil recovery factor of the conventional reservoirs [16]. There is still a large amount of oil remaining in place. It has attracted wide interest in the application of EOR techniques. Surfactant flooding has been seriously taken into account [3,29,19].

Surfactant flooding is one of potential Chemical Enhanced Oil Recovery (CEOR) techniques which is able to reduce the Interfacial Tension (IFT) between the aqueous and oil phases [22]. The wettability of the rock can also be influenced by the surfactant to help in changing the fluid properties, reduces the advanced drag, reduces the IFT, and decreases the mobility of capillary trapped oil [6]. Yuan and Lee [41] reviewed the contact angle measurement (basic and advanced) techniques for wettability determination of the materials at macro, micro, and nanoscale. The contact angle is the main measurement of the wettability. The surfactant that can change the wettability effectively also needs to withstand the high temperature and high salinity environment at the same time [25]. The surfactants can affect the flow distribution of fluids in the porous medium through wettability alteration [17].

However, with the lack of pilot test and field-scale experiment of surfactant injection in the Middle Bakken Formation, the simulation study cooperated with the laboratory data is critical to avoid risk and improve economic efficiency. Efforts have been devoted to simulation

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Nomenclature

EDFM	Embedded discrete fracture model
LGR	Local grid refinement
UTCHEM	University of Chemical Flooding Simulator
BHP	Bottomhole pressure
NNCs	Non-neighboring connections
CEOR	Chemical Enhanced oil recovery
EOR	Enhanced oil recovery
IFT	Interfacial tension
T_{NNC}	Transmissibility factor
K_{NNC}	Matrix permeability in the direction perpendicular to the fracture plane
A_{NNC}	Contact area of the fracture plane inside the matrix block
d_{NNC}	Distance related to the NNC
w_f	Fracutere width
k_f	Fracture permeability
L	Fracture-segment length
W	Fracture-segment height
p_i^{n+1}	Pressure in grid i at time $n+1$
p_i^n	Pressure in grid i at time n
q_{lsci}	Production rate of Phase l at standard conditions
$T^n_{lxi+1/2}$	Transmissibility of phase l in the boundary between grid i and $i+1$
$T^n_{lxi-1/2}$	Transmissibility of phase l in the boundary between grid i and grid i-1
e_L	Truncation error
Δx	Grid size
Δt	Time step
ad	Adsorbed moles per unit pore volume
$xnacl$	Salinity of the brine
ca	Mole fraction of surfactant in oil phase
$tad1$	Adsorption parameter
$tad2$	Adsorption isotherm associated with salt effects
$tad3$	Parameter coefficient
ω	Wettability Alteration Parameter
C_n	Total concentration of nanofluids
$\hat{C}_n$	Adsorbed concentration of nanofluids

studies of surfactant EOR in unconventional reservoirs in order to examine the recovery mechanisms and feasibility [8,21]. A 3-D multi-functional compositional numerical simulator of alkali/surfactant/polymer flooding was established, and various mechanisms and parameter effects were tested [40]. By using UTCHEM [23,1], simulated the surfactant and polymer flooding to find an optimized surfactant concentration. Wang et al. [31] also used the UTCHEM simulator to investigate the surfactant and polymer injection based on a reservoir condition [2] developed a 3-D numerical simulator to model the surfactant flooding by lowering the oil-water IFT and by altering the wettability of the matrix block to water-wet.

Black oil model is widely used to deal with the relevant chemical flooding in such simulator, and they almost do not have many fractures in the reservoir model. Even with black oil model and fewer fractures, the substantial computational burden makes it challenging to conduct the field case model with hydraulic fractures and comprehensive well controls [37]. Some important underlying physics might be masked due to the over-simplification of the simulation models [5], like complex fracture geometries which are often created during the hydraulic fracturing process [32] and various hydraulic fracture height in different layers [42]. In order to overcome these issues, a state-of-the-art EDFM was developed [33,34,35]. The EDFM method can conveniently model complex fractures [26,38,39]. Nevertheless, actual production data and reservoir properties with multiple hydraulic fractures were not available until last decade. A simulation model without actual production data will not be easy to match with the real case.

In this study, a surfactant EOR simulation model characterizing the reduction of the IFT and wettability alteration was built. A compositional model with seven pseudo-components was used to simulate a surfactant Huff-n-Puff process with an actual well and fluid properties from the Middle Bakken tight oil reservoir. We verified the effectiveness of the surfactant in a sector model after the optimal grid sensitivity analysis. We used the sector model to conduct our sensitivity studies with six uncertain factors including surfactant adsorption, surfactant concentration, surfactant injection time, surfactant injection rate, surfactant soaking time and the number of Huff-n-Puff cycles. The EDFM method was used in this study to tackle the computational burden. This study provides a better understanding of the key parameters affecting the surfactant Huff-n-Puff effectiveness in the Bakken tight oil reservoir.

2. Optimal grid size analysis

Optimal grid size analysis helps us to optimize the grid size that makes the model relatively accurate and time-saving. For instance, on account of the forward-difference approximation to the truncation Darcy flow equation (Explicate formulation) we used, and the capacity of our computer is not able to carry an infinite number of digits, the solution would differ from the exact solution of the original partial differential equation (PDE) [30] by:

$$p_i^{n+1} = p_i^n + \left(\frac{a_c B_l^o \Delta t}{V_b \varnothing c_l}\right)_i q_{lsci} + \left(\frac{a_c B_l^o \Delta t}{V_b \varnothing c_l}\right)_i \times [T^n_{lx_{i+1/2}} p^n_{i+1} - (T^n_{lx_{i+1/2}} + T^n_{lx_{i-1/2}}) p_i^n + T^n_{lx_{i-1/2}} p^n_{i-1}] \tag{1}$$

where p_i^{n+1} is the pressure in grid i at time $n+1$, p_i^n is the pressure in grid i at time n, q_{lsci} is the production rate of Phase l at standard conditions, $T^n_{lx_{i+1/2}}$ is the transmissibility of phase l in the boundary between grid i and $i+1$, $T^n_{lx_{i-1/2}}$ is the transmissibility of phase l in the boundary between grid i and grid i-1.

Therefore, the Truncation-Error analysis needs to be placed before the prediction of sensitivity study

$$e_L = \left[\frac{(\Delta x)^2}{12} \frac{\partial^4 p}{\partial x^4}\Big|_i^n - \frac{(\Delta t)}{2D_i} \frac{\partial^2 p}{\partial x^2}\Big|_i^n \right] \tag{2}$$

Or

$$e_L = O[(\Delta x)^2] + O(\Delta t) \tag{3}$$

where e_L is the truncation error, Δx is the grid size and Δt is the time step. We can find that the smaller Δx is, the smaller truncation error can achieve. The same results can be obtained from the backward-difference approximation and central-difference approximation.

In this case, we ran the grid sensitivity analysis with different grid sizes in Z direction. A good history match has been achieved and EDFM method has been verified, details are given in our previous paper [28]. The summarization of the model parameters as shown in Table 1.

In this grid sensitivity analysis, we injected two cycles of 0.2% surfactant solution with an injection rate of 1000 STB/day for 300 days and soaked for 20 days after the history match period. The surfactant adsorption parameter was 1 lbmole/ft^3. As we mentioned before, the equation of Truncation-Error indicates that the smaller grid size will have less Truncation-Error. We assumed that while the grid size decreases, the simulation is being more accurate. Therefore, according to the simulation results shown in Fig. 1, the sector model with 7, 9, and 11 layers in Z direction are relatively accurate.

In spite of the relatively same accuracy of these three cases, the CPU seconds for them have a huge difference, which are 4888, 9138 and 10,787 s, respectively. In this case, we used the 7-layer model which is

Table 1
History matching parameters for sector model.

Parameter	Value	Unit
Model dimension (x × y × z)	580 × 2150 × 50.4	ft
Number of gridblocks (x × y × z)	30 × 86 × 7	–
Initial reservoir pressure	7800	psi
Reservoir temperature	240	°F
Horizontal permeability	0.03	mD
Vertical permeability	0.003	mD
Initial water saturation	40%	–
Total compressibility	1×10^{-6}	psi^{-1}
Reservoir thickness	50.4	ft
Well length	578.8	ft
Stage spacing	236	ft
Fracture half-length	92.1	ft
Fracture height	50.4	ft
Fracture width	0.01	ft
Fracture conductivity	500	md·ft

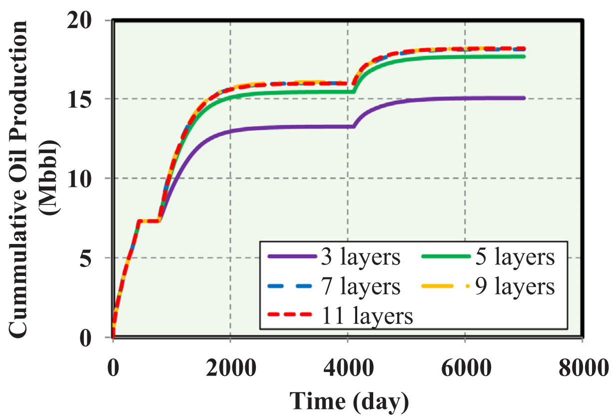

Fig. 1. Cumulative oil production comparison between different grid layers with surfactant flooding case.

the optimal one considering the accuracy and CPU time to continue our study. And also if we consider the round-off error which is caused by the increase number of operations in the computer, the 7-layer model costs lower CPU time indicating less round-off error proportionally.

3. Wettability alteration of surfactant flooding

The wettability alteration, a major surfactant EOR factor in the tight formation, is modelled by changing relative permeability curves and capillary pressure. In this model, wettability alteration is represented by the adsorbed surfactant concentration. A scaling factor, which averages the linear interpolation scheme, is used to characterize the relationship between wettability alteration and the adsorbed surfactant concentration. Since the surfactant isotherm may reach a plateau at a critical surfactant concentration, which is also called the Critical Micelle Concentration (CMC), and the injected surfactant concentration is normally much higher than the CMC. A Langmuir-type isotherm is applied to describe the adsorption process [7]:

$$ad = \frac{(tad1 + tad2 \times xnacl) \times ca}{(1 + tad3 \times ca)} \tag{4}$$

where *ad* is the adsorbed moles per unit pore volume, *xnacl* is the salinity of the brine, *ca* is the mole fraction of surfactant in oil phase, *tad1* is the adsorption parameter, *tad2* is the adsorption isotherm associated with salt effects, and *tad3* is the parameter coefficient.

Since the wettability alteration depends on the level of surfactant adsorption, the Wettability Alteration Parameter (ω) was proposed to represent the amount of surfactant adsorbed onto the rock surface [11]:

$$\omega = \frac{\hat{C}_n}{C_n + \hat{C}_n} \tag{5}$$

where C_n is total concentration of nanofluids and $\hat{C}_n$ is adsorbed concentration of nanofluids

Altering the wettability of an oil-wet system can result in favorable capillary pressure and relative permeability, enhancing spontaneous imbibition and recovery [10]. By using surfactant solution, the overall wettability state of the rock is altered toward a more water-wet condition in which water can then naturally be imbibed into the hydraulic fractures and to some extent into the natural fractures. In this study, we used the modification of relative permeability and capillary pressure curves to represent the wettability alteration in a commercial simulation software (CMG-STARS). The rock wettability altered from oil-wet to water-wet gradually. We adopted three different rock types that are oil-wet, mixed-wet and water-wet as shown in Fig. 2. We assume that the relative permeability curves for all the grids are same, and non-Darcy effect is not considered. Then the simulator can interpolate them to get a complex dynamic relative permeability curve along with the surfactant adsorbed into the reservoir. The capillary pressure data used in the study were based on the literature [20,4], as shown in Fig. 3.

The IFT data was selected from the literature [36], as shown in Table 2. The IFT versus Surfactant Concentration curve will be set into the model according to these points. As shown in the table, the surfactant can lower the interfacial tension significantly and efficiently. We used the Langmuir isotherm coefficients to define the surfactant adsorption, which means that the surfactant adsorption depends on the composition, as shown in Fig. 4.

4. Surfactant effectiveness verification

The surfactant EOR model was first run to evaluate the response of surfactant injection in Bakken well by comparing surfactant Huff-n-Puff process and primary production, as shown in Table 3. In the primary production case, the production well was producing with a minimum BHP constraint of 1500 psi after the history matching period. However, for the surfactant flooding Huff-n-Puff case, there are two cycles of Huff-n-Puff conducted in the well constraints. In each Huff-n-Puff case, at the maximum BHP constraint of 7800 psi, 0.2 wt% of surfactant was injected at an injection rate of 1000 bbl/day for 300 days. After the injection period, the injection well was shut in to soak for 20 days. This is one cycle of the Huff-n-Puff. The well constraint of production well was set with a minimum BHP of 1,500 psi.

The comparison of cumulative oil production is shown in Fig. 5. The oil recovery factor after the first surfactant Huff-n-Puff cycle has already been a little bit higher than that of the primary production. After the second Huff-n-Puff cycle, the oil recovery factor achieves a much higher value than the primary production, about 0.9% oil recovery factor increased. Therefore, the surfactant flooding is more efficient than the primary production.

To analyze the mechanisms of the surfactant solution, the adsorbed surfactant map is shown in Fig. 6(a), and the IFT map is shown in Fig. 6(b). For the grids close to the fracture, higher surfactant concentration appeared compared with the grids far from the fractures. It means that the IFT reduced with the surfactant adsorbed onto the rock. With the lower IFT and the rock wettability changed from oil-wet to water-wet, the oil production increased.

5. Sensitivities analysis for surfactant EOR in the Middle Bakken

A sensitivity analysis is important given the significant risks associated with chemical EOR projects. Following the assessment of the base case simulation, a series of simulations were performed to investigate the impact of different parameters on oil recovery during surfactant Huff-n-Puff process. Since the surfactant concentration is not the only sensitivity factor which can influence the wettability

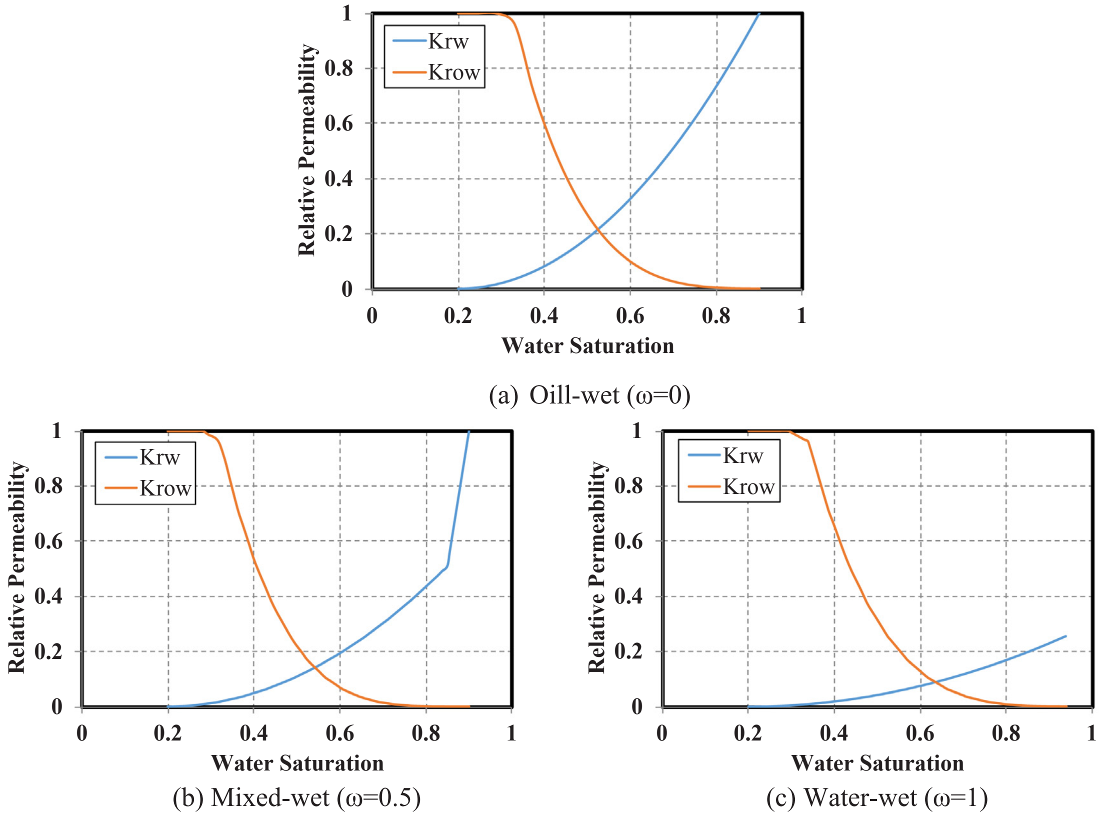

Fig. 2. Three inputted oil-water relative permeability curves for different rock wettability conditions.

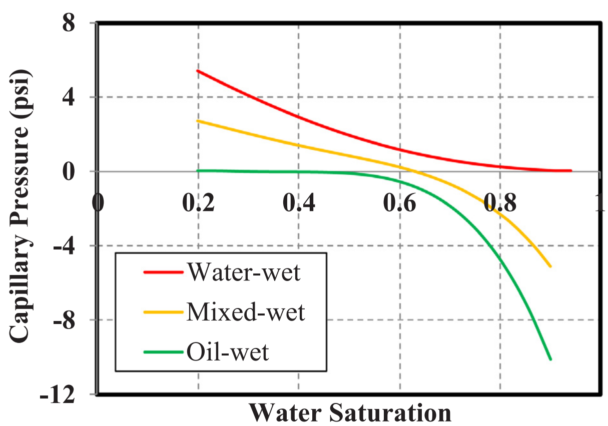

Fig. 3. Three inputted capillary pressure curves for different rock wettability conditions [20,4].

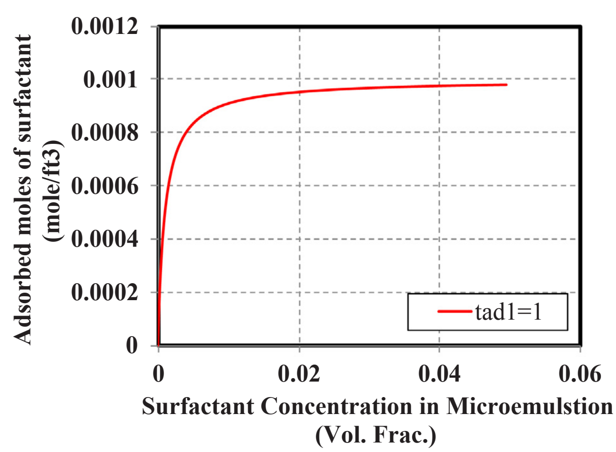

Fig. 4. The Langmuir adsorption isotherm curve.

Table 2
Surfactant IFT Table [36].

Surfactant Concentration (wt. %)	Interfacial tension (dyn/cm)
0	23.1
0.1	0.17
0.2	0.014
0.3	0.0047
0.4	0.0089
0.5	0.0154

Table 3
Schedule comparison between surfactant Huff-n-Puff and primary production.

Time (days)	Primary production	Surfactant Huff-n-Puff
0	History match	History match
450	Produce	Surfactant injection
750	Produce	Soaking
770	Produce	Produce
3775	Produce	Surfactant injection
4005	Produce	Soaking
4025	Produce	Produce
7000	STOP	STOP

alteration, six sensitivity factors in different scenarios were designed for sensitivity studies. All scenarios were performed by adjusting one parameter at a time within a reasonable range and leaving the remaining parameter identical to the base case. The parameters used in this analysis served the purpose of obtaining the optimum design and testing the effects of key uncertain parameters were surfactant adsorption, surfactant injection time, soaking time, surfactant injection

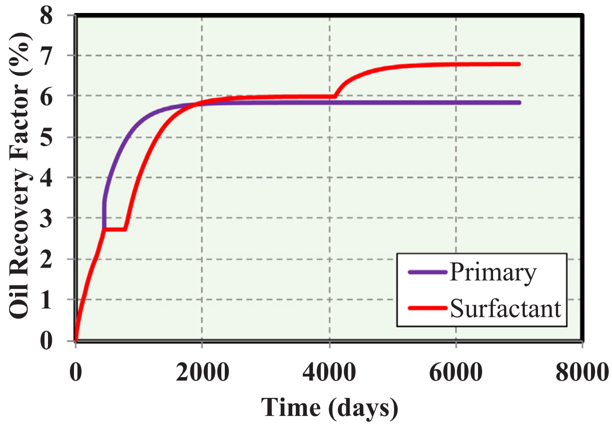

Fig. 5. Oil recovery factor comparison between the primary production and surfactant flooding case.

rate, surfactant concentration, and the number of surfactant Huff-n-Puff cycles. The retardation factor was not taken into account in this study.

The maximum BHP was set to be 7,800 psi based on the initial reservoir pressure. The minimum BHP was set as 1500 psi, which was selected based on the literature review. Table 4. summarizes the value of parameters used for sensitivity studies.

6. Effect of surfactant adsorption

For the simulations of surfactant adsorption scenarios, two more cases were investigated, besides the base case. The surfactant adsorption parameter (tad) was changed to 0.5 lbmole/ft^3 and 1.5 lbmole/ft^3. The surfactant adsorption curves are shown in Fig. 7.

Other parameters were kept unchanged. These two case studies were compared with the base case and primary production. As shown in Fig. 8, after the history matching period, the cumulative oil production without surfactant injection (primary production) is the highest one, followed by 0.5 lbmole/ft^3, 1.0 lbmole/ft^3 and 1.5 lbmole/ft^3. At the

Table 4
Parameters and their range for surfactant Huff-n-Puff sensitivity analysis.

	Low	Base	High
Adsorption (lbmole/ft^3)	0.5	1	1.5
Surfactant injection time (days)	150	300	450
Surfactant soaking time (days)	5	20	35
Number of cycles	1	2	3
Injection rate (STB/day)	500	1000	1500
Surfactant concentration (mole fraction)	0.0005	0.002	0.005

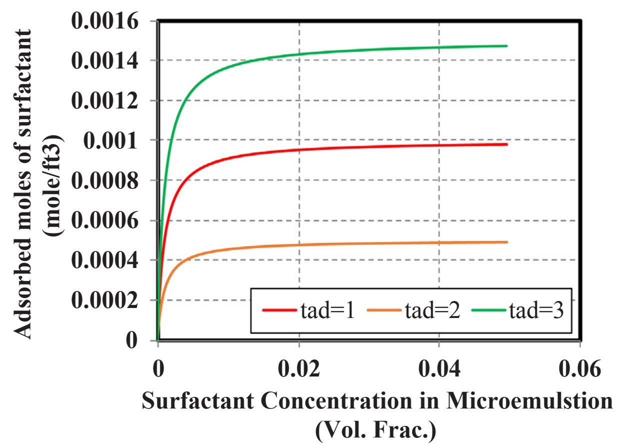

Fig. 7. The comparison of three different Langmuir adsorption isotherm curves.

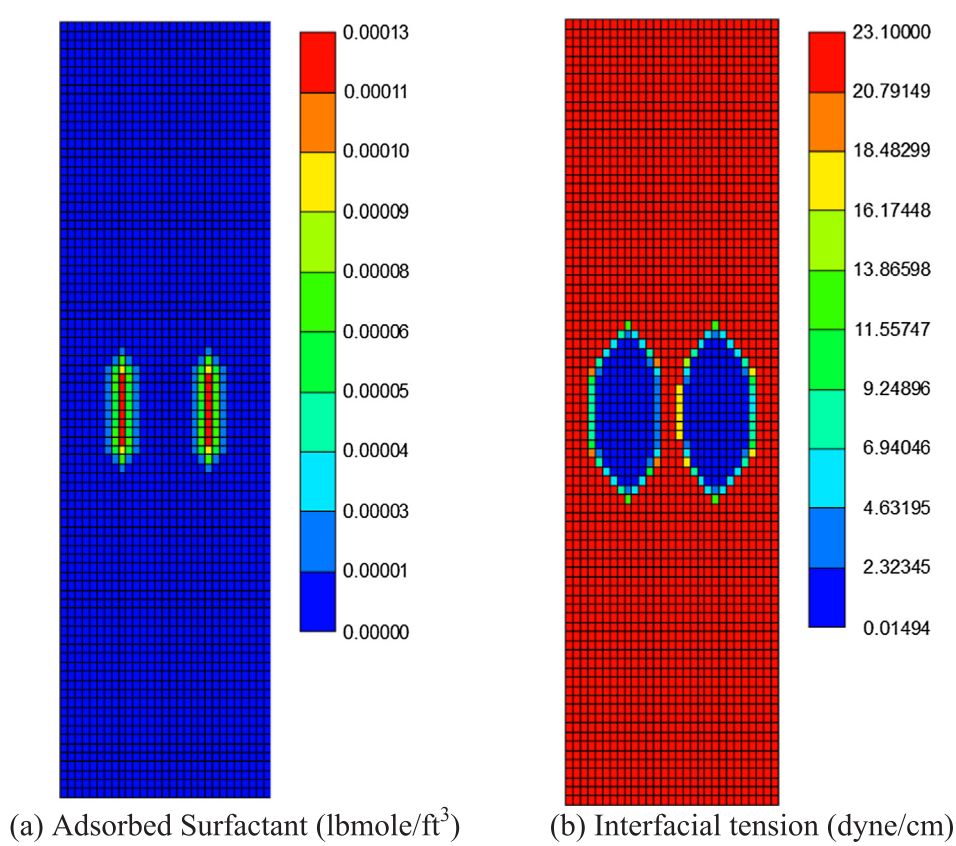

Fig. 6. Adsorbed mole of surfactant and IFT in the end of surfactant flooding.

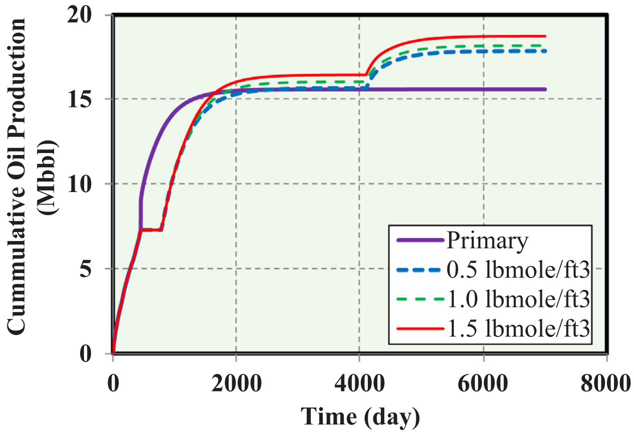

Fig. 8. Effect of different surfactant adsorption on surfactant Huff-n-Puff effectiveness.

time of 1700 days, in the middle of the first surfactant Huff-n-Puff cycle, the cumulative oil production almost does not change. After 1700 days, the case with high surfactant adsorption produces the highest cumulative production oil, followed by cases with lower surfactant adsorption rates. At the end of the simulation, cumulative oil production of the case with 1.0 lbmole/ft^3 surfactant adsorption is close to that of the case with 0.5 lbmole/ft^3 surfactant adsorption but lower than the cumulative oil production of simulation case with 1.5 lbmole/ft^3 surfactant adsorption. The contribution to cumulative oil production after 7000 days is about 14.4%, 16.4%, and 20.0% for three surfactant Huff-n-Puff cases with the surfactant adsorption of 0.5 lbmole/ft^3, 1.0 lbmole/ft^3, and 1.5 lbmole/ft^3, respectively. The higher adsorption leads to a higher cumulative oil production, which indicates that the more wettability change from oil-wet to water-wet is better for higher oil recovery factor.

7. Effect of surfactant injection time

Three cases were run to investigate the effect of surfactant injection time on oil production. The surfactant injection time was 300 days/stage, 150 days/stage and 450 days/stage for three cases, respectively. Other parameters were not changed. The base case and primary production were also used as the reference to compare the incremental oil production. A comparison of the cumulative oil recoveries for each scenario is depicted in Fig. 9. The primary production is the highest one in the beginning. At the time of 1500 days, the case with 150 days/stage injection time surpasses the primary production and becomes the highest oil production. At the time of 1800 days, the base case that is 300 days/stage injection time became the highest one. The case with 450 days/stage injection time is still the lowest production until the time at 2200 days. However, this case has the highest oil production at the end of the simulation, which is 18.3% higher than primary production. The case with 150 days/stage and 450 days/stage were 15.5% and 16.4% higher than the primary production, respectively. According to the simulation results with different injection time, the surfactant Huff-n-Puff process with longer injection time did have higher oil recovery in the end. The case with higher injection time had less oil recovery in the beginning. Therefore, it is important to design an optimum ratio between injection time and production time according to the total working time of the well.

8. Effect of surfactant soaking time

In this surfactant soaking time scenario, three case studies were conducted. The surfactant soaking time was modified from 20 days/stage to 5 days/stage and 35 days/stage. The cumulative oil production rate of the case with 35 days/stage soaking time surpassed the primary production at the time of 1,700 days, as shown in Fig. 10, and was higher than the other two cases. The percentage of recovery increased over the primary recovery reached 19.0%. The cumulative oil rates of the case with 20 days/stage and the case with 5 days/stage were almost the same, with percentage of recovery increasing over the primary recovery of 16.4% and 16.0%, respectively. The various surfactant soaking time in this study yielded a small difference in cumulative oil production. The effect of soaking time may not be estimated accurately in the simulations because the mathematical models of multiphase flow generally assume a local thermodynamic equilibrium and disregards the reaction kinetics and the necessary interaction time for the surfactant to alter the rock wettability [18].

9. Effect of number of cycles on surfactant Huff-n-Puff

Three scenarios with 1, 2, and 3 Huff-n-Puff cycles were simulated to study its effect on oil recovery. The case study with 1 cycle of surfactant Huff-n-Puff process was started at the time of 450 days. The case with 2 cycles started at the time of 450 days and 3775 days. The case with 3 cycles started at the time of 450 days, 2650 days and 4800 days. As shown in Fig. 11, after the first Huff-n-Puff cycle, the oil production rates of all three cases surpassed the oil rate of the primary production. After the second Huff-n-Puff cycle, the cumulative oil rates of cases with 2 and 3 cycles surpassed the case with one Huff-n-Puff cycle. After the third Huff-n-Puff cycle, the case with three cycles yields the highest cumulative oil production. The percentage of recovery increase over the primary recovery for cases with one, two and three cycles was 2.7%, 16.4% and 25.2% respectively. All of the cases with Huff-n-Puff process have higher cumulative oil production than the primary production. Therefore, the surfactant Huff-n-Puff process is beneficial for EOR. The incremental oil production will increase while the number of Huff-n-Puff cycles increases. However, as we can see, with the Huff-n-Puff cycles increasing, the degree of incremental oil production is decreasing. It means that with more surfactant Huff-n-Puff cycles, like 5 or 6 cycles, the incremental oil production may not increase a lot. Even so, we can still have the conclusion that with more surfactant Huff-n-Puff cycles, the higher cumulative oil production we will get.

10. Effect of surfactant injection rate

In this surfactant injection rate scenario, we discovered the relationship between the different surfactant injection rates and cumulative oil production. The surfactant injection rates were 500 bbl/day, 1000 bbl/day and 1500 bbl/day in three simulation cases. As shown in Fig. 12, three case studies all surpassed the primary production at the time of 2000 days. Moreover, they have almost the same cumulative oil production in the end of the simulation. The percentage of recovery increased over the primary recovery for these three cases was 16.7%,

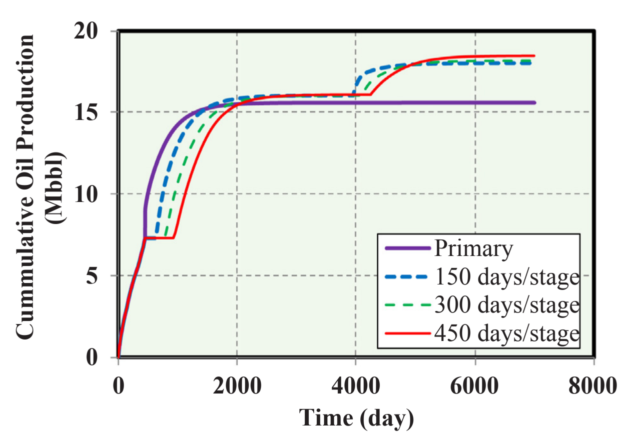

Fig. 9. Effect of different CO_2 injection times on CO_2 Huff-n-Puff effectiveness.

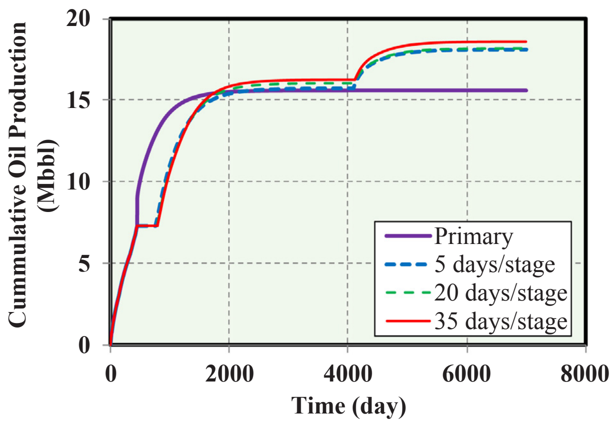

Fig. 10. Effect of different CO_2 soaking times on CO_2 Huff-n-Puff effectiveness.

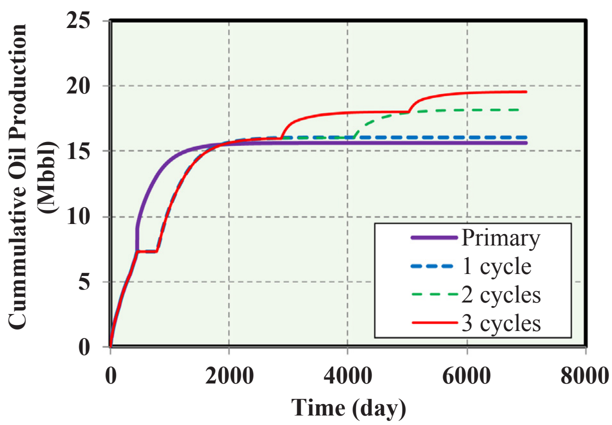

Fig. 11. Effect of number of cycles on surfactant Huff-n-Puff effectiveness.

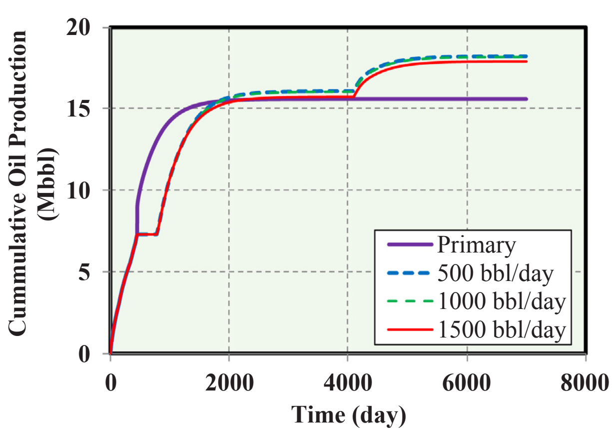

Fig. 12. Effect of different surfactant injection rate on CO_2 Huff-n-Puff effectiveness.

16.4% and 14.7%, respectively. It seems that the high injection rate has a negative effect for cumulative oil production. The three curves in the figure are all close to each other. It means that within a reasonable range, the surfactant injection rate will not affect the ultimate oil recovery factor a lot under the surfactant Huff-n-Puff process.

11. Effect of surfactant concentration

Three case studies were investigated in this surfactant concentration scenario. The surfactant concentrations considered were 0.05 wt%, 0.20 wt% and 0.50 wt%. As shown in Fig. 13, three cases indicate that the case with the surfactant concentration of 0.5 wt% maintains the highest cumulative oil throughout the simulation. Compared with other sensitivity studies, it is not difficult to find that the concentration of the surfactant can increase the oil production directly and rapidly, like the surfactant injection time, soaking time, Huff-n-Puff cycles, and so on. The percentage of recovery increase over the primary recovery of the surfactant concentration with 0.05 wt%, 0.2 wt% and 0.5 wt% are 1.1%, 16.4% and 19.4%, respectively. It indicates that with the higher the surfactant concentration, the higher the cumulative oil production will be. However, the surfactant cost will be higher. It also suggests that the accurate balance between the surfactant concentration and incremental oil production needs to be considered.

To evaluate the relative impact of the parameters, the impacts of all uncertain parameters on the EOR effectiveness at 7000 days of production are shown in the Tornado plot (Fig. 14). It is clear that the number of surfactant Huff-n-Puff cycles and the surfactant concentration have the largest effect on EOR. Moreover, it is followed by surfactant adsorption, soaking time, injection time and rate in order. This rank is based on the range of each parameter used in this study. The range for the percentage of recovery increase over the primary recovery at the time of 7000 days of production is about 1.1% − 25.2%.

12. Conclusions

Based on a true reservoir and fracture properties of the Middle Bakken Formation, a numerical reservoir model with multistage hydraulic fractures was built to simulate surfactant Huff-n-Puff process using a reservoir simulator and EDFM method for fracture modelling. Depending on the amount of surfactant adsorbed to the rock surface, the wettability of the rock can be altered to varying degrees by changing the relative permeability and capillary pressure. We used the Langmuir-type isotherm curve to describe the surfactant adsorption. A numerical chemical flooding model (CMG-STARS) in combination with the EDFM method is proposed to simulate the surfactant flooding in tight oil reservoirs with hydraulic fractures. This model can not only be used in the Middle Bakken formation, but also in other unconventional tight oil reservoirs. The surfactant and fluid properties, wettability alteration, optimal model size, and historical production data are accurately considered. The fluid compositional model is validated through history matching with actual Middle Bakken tight oil. The effects of different surfactant Huff-n-Puff parameters and surfactant adsorption parameters on the surfactant Huff-n-Puff effectiveness were examined. The following conclusions can be made from this study:

(1) The model and fluid properties used in this study are similar to the actual field case, and the grid size is also optimized by a grid sensitivity analysis. A great agreement was achieved between the

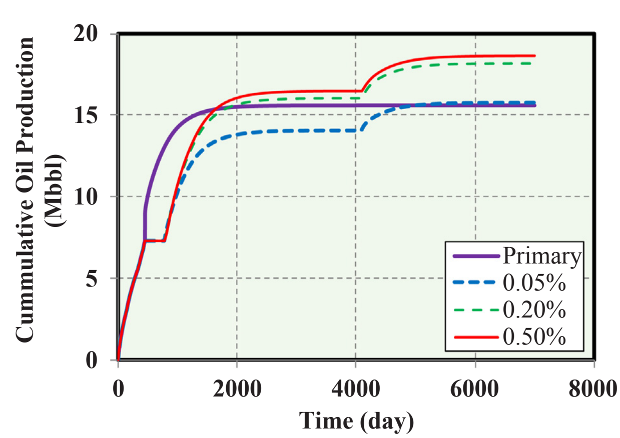

Fig. 13. Effect of surfactant concentration on surfactant Huff-n-Puff effectiveness.

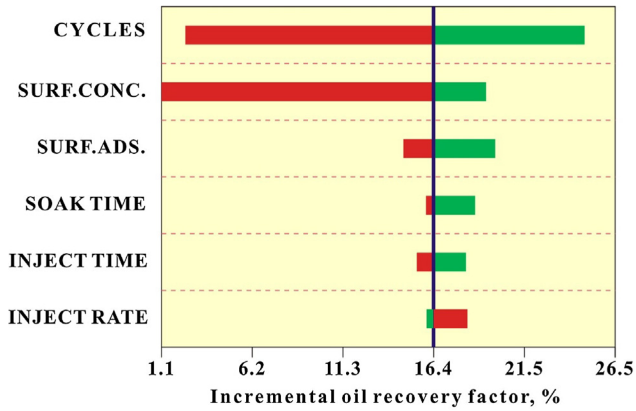

Fig. 14. Rank of six uncertain impact parameters on incremental oil recovery factor.

historical production data and the simulation results. Both field model and sector models can match the actual historical data.

(2) The effect of surfactant EOR was simulated by considering the IFT reduction and the rock wettability alteration from oil-wet to water-wet according to the Langmuir-type isotherm curve of the adsorption of the surfactant concentration.

(3) A surfactant effectiveness verification was conducted before the sensitivity studies, and an actual production process was conducted at the beginning of each sensitivity case study. With the effective surfactant flooding and good history match, the reservoir and fluid properties are extremely close to the real case which means that the simulation study can be considered with the actual production process. Therefore, this surfactant flooding study is actually meaningful for practical workers to use for reference.

(4) The case with three surfactant Huff-n-Puff cycles has the highest cumulative oil production that the percentage of recovery increase over the primary recovery can reach 25.2% and also for the case with the highest surfactant concentration which can reach 19.4% of the percentage of recovery increase over the primary recovery. Both of them have a high surfactant injection. Therefore, the amount of surfactant injected into the reservoir is the key to increasing production.

(5) In this surfactant Huff-n-Puff study, the contribution of each surfactant Huff-n-Puff parameter to cumulative oil production after 7000 days can be ranked into two groups: 1. The number of surfactant Huff-n-Puff cycles and surfactant concentration. 2. Surfactant adsorption, injection time, soaking time, and injection rate. The parameters in the first group have a larger effect on EOR, and the parameters on the other group only have a slighter effect.

(6) EDFM method proposed in this study can simulate the wettability alteration and surfactant Huff-n-Puff process in the tight oil reservoirs with multiple hydraulic in a simpler and more fast way.

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