Research Article

Modelling Low-Salinity Water Flooding as a Tertiary Oil Recovery Technique

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Received 27 August 2019; Revised 1 September 2020; Accepted 30 September 2020; Published 26 October 2020

Academic Editor: Agostino Bruzzone

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In this project, low-salinity water flooding has been modeled on ECLIPSE black oil simulator in three cases for a total field production life of twenty-five years. In the first case, low-salinity water flooding starts fifteen years after secondary water flooding. For the second case, low-salinity water flooding starts five years after secondary water flooding and runs till the end of the field production life. For the third case, low-salinity water flooding starts five years after secondary water flooding, but low-salinity water flooding is injected in measured pore volumes for a short period of time; then, high-salinity water flooding was resumed till the end of the field production life. This was done to measure the effect of low-salinity water flooding as slug injection. From the three cases presented, oil recovery efficiency, field oil production rate, and field water cut were observed. Increased percentages of 22.66%, 35.12%, and 26.77% were observed in the three cases, respectively.

1. Introduction

Secondary injection schemes (water and gas injections) have majorly been carried out on oil reservoirs to improve oil recovery after the depletion of the natural energy of the reservoir [1]. Considerable oil is always left to be recovered due to the nature of the interactions between reservoir fluids and the rock properties. An enhanced form of oil recovery is always needed in cases like this to reduce residual oil left. Options for enhanced oil recoveries are screened majorly on reservoir fluids and rock properties and costs of implementation all with respect to the amount of oil to be recovered.

Low-salinity water flooding most recently has been considered as more than just a water flooding technique (secondary recovery); it has been considered to be an improved oil recovery technique due to the chemical reactions that take place when water having a reduced ionic content (reduced salinity) is used for water flooding [2]. Due to its simplicity and low application costs, the procedure has gained many interests in the oil industry [3]. Numerous experiments that have been conducted have shown the effects of low-salinity water flooding on oil production. Over the last decades, several researches have been carried out to understand the mechanisms behind low-salinity water flooding as it relates to increasing oil recovery, but no mechanism has been singled out to be the main mechanism responsible for the low salinity effect. Among these mechanisms are fines migration, mineral dissolution, wettability change, double-layer expansion, and multicomponent ion exchange (MIE) [4, 5].

It should however be noted that fresh water cannot be used in the name of using low-salinity water, because fresh water would cause clay swelling in the core which would completely block the core pores. Therefore, before a water flooding operation is carried out, there must be proper modification of the brine to be used in order to get optimum oil recovery [6].

It has however been observed that there is a significant drop in permeability that can cause increased pressure drop after flooding with lower-salinity water than the connate water in the reservoir [7]. During low-salinity water flooding, a reduction in the concentration of salinity in the injected fluid would result in the earlier stated condition. In a scenario
where there is a high base/acid ratio, the polar components in crude oil are not affected by the salinity concentration on the injected water. From this observation, it could be concluded that when the concentration of divalent cations on the clay surfaces are reduced, there would be an increased retention; hence, the wettability of a rock system could be altered to a more water wet condition [8].

During an experiment conducted by Romero et al. [9] on Berea sandstone, high-salinity water was alternated with low-salinity water at different concentrations to measure and see the effect of alternating flooding. One of the core samples was flooding with high- and low-salinity water in two separate experiments. Their results showed that during low-salinity flooding, there is a reduction in the increase of pH alongside temperature and pressure drop. While the permeability reduction during flooding is not reversible, the pH on the other hand is reversible and was concluded to be roughly dependent on the degree of dilution.

To optimize the factors that affect oil production during low-salinity flooding, Tang and Morrow [10] performed several experiments to observe the effect of aging time, temperature of displacing fluid, and the compositional effect of brine and oil on wettability and its effect on recovery of oil during spontaneous imbibition and water flooding. The experiment was carried out on Berea sandstone using three crude oil and synthetic brine samples. In order to analyze the correlation between wettability and oil recovery, the authors used the relative positions of imbibition curves instead of using a single parameter like in the Amott index to water. From the experiments, there was an increased oil recovery got from water flooding with an increased oil recovery from slow initial imbibition. This effect was attributed to the increased wetness of water phase due to a combined action of the oil/water interface and increased water saturation. When a particle is put into a fluid, in order to balance the ionic charges surrounding the particle, there is the formation of an electric double layer. It comprises of different charges surrounding the particle. The thickness of this double layer that forms is dependent on the electric charges and can be measured from zeta potential which is the potential at the shear plane of the double layer [11].

Simulation studies have proven to be easier methods of optimizing factors that positively affect oil production in any reservoir and most especially under low-salinity water flooding. It allows for factors such as porosity, permeability, well trajectory, production, and injection rates to be varied [12, 13].

Al-Aulaqi et al. [14] observed that increasing aging time caused imbibition rate to decrease. The authors also observed from the results obtained during experiments that connate water had an influential role in the oil recovery; the presence of connate water caused an oil recovery of 19%, while the absence of connate water caused an oil recovery of 46%. When the salinity is sufficiently reduced, the repulsion in the charges increased so much as to cause a large increase in the double layer. This would cause desorption of the oil particles (positive charge) from the negatively charged rock surfaces leading to an alteration in the rocks wetness state to water wet [15].

![Table 1: Reservoir description.](image)

| Grid type | 15, 15, 3 |
| Block measurement | 10 m |
| Porosity | 0.25 |
| Permeability (XX, YY) | 200 mD |
| Permeability (ZZ) | 20 mD |
| Injector well | 1 |
| Producer well | 1 |
| Rock compressibility | 2.70E – 03 |

![Table 2: Equilibrium data properties.](image)

| Datum depth | 2680 m |
| Pressure at datum depth | 270 bars |
| Water-oil contact (WOC) depth | 2680 m |
| Gas-oil contact (GOC) depth | 2000 m |

![Table 3: Dead oil properties.](image)

| Pressure (bars) | Formation volume factor (FVF) (rm³/sm³) | Visc (cp) |
|-----------------|-----------------------------------------|-----------|
| 200             | 1                                       | 0.47      |
| 280             | 0.999                                   | 0.47      |
| 300             | 0.998                                   | 0.47      |

![Table 4: Fluid densities (kg/m³).](image)

| Water | 1000 |
| Oil   | 850  |
| Gas   | 1.2  |

### 2. Methodology

In order to observe the effect of low-salinity water flooding as a tertiary oil recovery technique, a simple black oil reservoir model is used with the ECLIPSE simulator. The reservoir description is shown in Table 1, while Tables 2–4 describe the reservoir equilibration, pressure volume, and temperature properties and fluid densities, respectively. Figure 1 shows the reservoir model with two wells initiated at the two extreme edges.

Average porosity and permeability values are used to describe the model properties. Two horizontal wells are initialized at (15, 15) for the producer and (1, 1) for the injector at a depth of 2600 m. Both wells are set to produce and inject at the same rate of 100 m³/day. The simulation was made to run from 1st Jan 1990 till 1st Jan 2015 (25 years). In order to simulate low-salinity water flooding as a tertiary oil recovery technique, the simulation ran such that high salinity/seawater (30 ppm) injection commences at the onset of
production both occurring at the rate of 100 m$^3$/day. After running the above files on an ECLIPSE black oil simulator, the results were analyzed and are explained in the nomenclature. A base case scenario of initial water flooding is executed to give a recovery of 0.57.

### 3. Results and Discussion

3.1. Case 1. The scenario in Case 1 is such that water flooding commences at the onset of oil production with the same rate of production (100 m$^3$/day). This secondary flooding is
carried out with high-salinity water with salt concentration of 30 ppm for the first fifteen years; this is then followed by low-salinity water flooding for the next 10 years. Field oil efficiency or field oil recovery (FOE) increases with decrease in concentration of the salt concentration. The FOE at the end of secondary flooding (i.e., after fifteen years) was 0.63, but when subjected to tertiary water flooding using fresh water having 0 ppm, 2 ppm, 5 ppm, 10 ppm, 20 ppm, and 30 ppm, the observed results are shown in Table 5. Figure 2(a) shows the trends of oil recovery at different salinity with a 0% saline concentration giving the highest recovery of 0.76. The field water cut (FWCT) was observed to decrease (as shown in Figure 2(b)) when the concentrations are reduced.

3.2. Case 2. The scenario in Case 2 involved the initial injection of high-salinity water of 30 ppm from the onset of water production till five years followed by low-salinity water flooding till the end of the field production life cycle (i.e.,
twenty years of low-salinity water flooding). Just as it was in Case 1, the initial volumetric flow rate from the producer and through the injector well was 100 m$^3$/day. The oil recovery (Figure 3(a)) increased with a reduction of salt concentration at the end of the first five years. The injection of very-high-salinity water of 30 ppm resulted in an oil recovery of 0.59 but after flooding with fresh water having 0 ppm, 2 ppm, 5 ppm, 10 ppm, and 20 ppm of salt concentration, it is observed that the oil production rate and oil recovery (Figures 3(c) and 3(a)) increase as the saline content reduces and observed results are shown in Table 6. The trend recorded for water cuts suggests that the lower the saline content is, the lower the water cuts are. The significant reduction observed is attributed to the reduction in relative permeability of water due to the wettability alteration that occurs during low-salinity water flooding.

The production rates described in Figures 2(c) and 3(c) show a steady drastic decline from 100 m$^3$/day to as low as 5 m$^3$/day for both cases and peaked again to 12 m$^3$/day and 14 m$^3$/day for Case 1 and Case 2, respectively. The plots also indicate a higher production rate for lower saline concentrations. Figure 3(c) is an expansion of the production rate period of Figure 3(d) for better visualization.

3.3. Case 3. The injection patterns for Case 3 are simulated under 2 different salt concentration conditions of 2 ppm and 20 ppm which are taken as boundary conditions. The injection program was done in such a way as to imitate a slug flooding injection pattern, but the major difference in this case was that the injections are done at successions of different pore volumes for a short period of time as described in Table 7. As was in the two previous cases, the producer and injector wells had the same flow rate of 100 m$^3$/day. The data in Table 7 describes the pore volume injection simulation for low salt at 2 ppm (runs 1-7) and (runs 8-14) at 20 ppm. It is discovered that oil recoveries during low-salinity flooding at different pore volume of 2 ppm are greater than flooding at pore volume of 20 ppm as shown in Figures 4(a) and 4(b), respectively. Also, the higher the pore volume concentration injection is, the higher the oil recovery for both cases is. The percentage change in FOE at the end of tertiary flooding when compared with FOE at the end of primary oil recovery is shown in Table 7. Lower saline concentrations resulted in a higher water cut generally for all the pore volumes injected (Figures 4(c) and 4(d)). Water cuts are expected to be high as water is the base fluid for injection. Figures 4(e) and 4(f) describe the oil production rate trend at different concentrations. They show a trend of an increasing oil production rate as saline concentration increases. These figures are the abridged forms of Figures 4(g) and 4(h). The summary in the figures generally indicates a higher flow rate at 2 ppm compared to 20 ppm at all pore volumes injected.

| Run no. | File name | Injection duration (years) | Pore volume (PV) low sal injected | % change in recovery factor (FOE) |
|---------|-----------|-----------------------------|-----------------------------------|----------------------------------|
| 1       | 2% SC @ 0.11 PV injected (A1) | 0.5                          | 0.11                              | 10.98                            |
| 2       | 2% SC @ 0.216 PV injected (A2) | 1                            | 0.216                             | 12.62                            |
| 3       | 2% SC @ 0.433 PV injected (A3) | 2                            | 0.433                             | 16.59                            |
| 4       | 2% SC @ 0.76 PV injected (A4) | 3                            | 0.76                              | 21.03                            |
| 5       | 2% SC @ 1 PV injected (A5)    | 7.417                        | 1                                 | 27.23                            |
| 6       | 2% SC @ 1.5 PV injected (A6)  | 7                            | 1.5                               | 26.77                            |
| 7       | 2% SC @ 2 PV injected (A7)    | 9.417                        | 2                                 | 28.93                            |
| 8       | 20% SC @ 0.11 PV injected (B1) | 0.5                          | 0.11                              | 10.30                            |
| 9       | 20% SC @ 0.216 PV injected (B2) | 1                            | 0.216                             | 10.60                            |
| 10      | 20% SC @ 0.433 PV injected (B3) | 2                            | 0.433                             | 11.16                            |
| 11      | 20% SC @ 0.76 PV injected (B4) | 3                            | 0.76                              | 11.91                            |
| 12      | 20% SC @ 1 PV injected (B5)   | 7.417                        | 1                                 | 13.37                            |
| 13      | 20% SC @ 1.5 PV injected (B6) | 7                            | 1.5                               | 13.25                            |
| 14      | 20% SC @ 2 PV injected (B7)   | 9.417                        | 2                                 | 13.85                            |

Similar plot profile trend is obtained for the FWCT as in Case 1 and Case 2.

Table 6: Oil recovery factor for Case 2.

| Run no. | File name | Time (years) | Recovery factor (RF) |
|---------|-----------|--------------|----------------------|
| 1       | 0% salt conc. | 20           | 0.797                |
| 2       | 2% salt conc. | 20           | 0.796                |
| 3       | 5% salt conc. | 20           | 0.763                |
| 4       | 10% salt conc. | 20          | 0.716                |
| 5       | 20% salt conc. | 20          | 0.668                |

Table 7: Percentage oil recovery efficiency for Case 3.
Figure 4: Continued.
Figure 4: (a) FOE for Case 3 at 2 ppm. (b) FOE for Case 3 at 20 ppm. (c) FWCT for Case 3 at 2 ppm. (d) FWCT for Case 3 at 20 ppm. (e) FOPR for Case 3 at 2 ppm. (f) FOPR for Case 3 at 20 ppm. (g) FOPR for Case 3 at 2 ppm. (h) FOPR for Case 3 at 20 ppm.
Table 8: FOPT for all cases.

| Run no. | File name | Duration (years) | FOPT (sm³/day) | % increase in FOPT |
|---------|-----------|-----------------|----------------|--------------------|
| 1       | Case 1    | @ 30% SC        | 10             | 86297              | 0                  |
| 2       | Case 1    | @ 0% SC         | 10             | 103577             | 20.0               |
| 3       | Case 1    | @ 2% SC         | 10             | 99898              | 15.8               |
| 4       | Case 1    | @ 5% SC         | 10             | 95827              | 11.0               |
| 5       | Case 1    | @ 10% SC        | 10             | 93418              | 8.3                |
| 6       | Case 1    | @ 20% SC        | 10             | 88604              | 2.7                |
| 7       | Case 2    | @ 0% SC         | 20             | 107725             | 24.8               |
| 8       | Case 2    | @ 2% SC         | 20             | 107725             | 24.8               |
| 9       | Case 2    | @ 5% SC         | 20             | 99395              | 15.2               |
| 10      | Case 2    | @ 10% SC        | 20             | 96685              | 12                 |
| 11      | Case 3    | A7              | 9.417          | 101119             | 17.2               |
| 12      | Case 3    | A1              | 0.5            | 87039              | 0.9                |
| 13      | Case 3    | A2              | 1              | 88331              | 2.4                |
| 14      | Case 3    | A3              | 2              | 91438              | 6                  |
| 15      | Case 3    | A4              | 3              | 94927              | 10                 |
| 16      | Case 3    | A5              | 7              | 99426              | 15.2               |
| 17      | Case 3    | A6              | 7.417          | 99789              | 15.6               |
| 18      | Case 3    | B6              | 1              | 86740              | 0.5                |
| 19      | Case 3    | B5              | 2              | 87181              | 1                  |
| 20      | Case 3    | B4              | 3              | 87774              | 1.7                |
| 21      | Case 3    | B3              | 7.417          | 88917              | 3                  |
| 22      | Case 3    | B2              | 7              | 88820              | 2.9                |
| 23      | Case 3    | B1              | 9.417          | 89295              | 3.5                |
| 24      | Case 3    | B7              | 0.5            | 86512              | 0.25               |

Table 8 shows the summary of total oil production and percentage increase in oil production for all the cases considered. The base case scenario used was the secondary water flooding with high-salinity water of 30 ppm.

4. Conclusion and Recommendation

The results above indicate that low-salinity water flooding is an effective enhanced oil recovery scheme as seen in the different case scenarios considered. Injection schemes might be useful to marginal field operators who need to implement a simple and cheap enhanced recovery method. The observed case scenarios show that at a very low saline concentration, oil recovery can be as high as 76%, 80%, and 75% as in Cases 1, 2, and 3, respectively. In Case 3, it is observed that increasing the volume of the pore injected caused low salinity effect to last for a longer time. Proper screening criteria on EOR methods should be carried out on a reservoir before selection. Due to high water cuts across the cases, operators will have to consider the cost of water treatment facilities for the period of use. Thus, related EOR schemes such as prescribed by Olabode et al. [16] and Olabode et al. [17] should be considered. The results obtained in this project are ideal results but did not consider other physical factors. In order to obtain optimum results, physical parameters like fines migration could plug pore throats and swelling of clay fines. I would recommend that before field implementing of low-salinity water flooding, experiments should be carried out on core plugs then upgraded to field scale models before concluding that low-salinity water flooding would be beneficial to a field.

Nomenclature

FOE: Field oil efficiency or recovery factor
FOPR: Field oil production rate
FWCT: Field water cut
FOPT: Field oil production total.

Data Availability

Data will be made available through the corresponding author on request.

Conflicts of Interest

There are no conflicts of interests in the development of this research.
Acknowledgments

The authors thank the Department of Petroleum Engineering at Covenant University for an enabling environment to carry out the research and funds for publishing.

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