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EVALUATION OF WATER FLOODING TO INCREASE RECOVERY OF OIL

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Evaluation of Water Flooding To Increase Recovery of Oil

Asaf Ali

Research Scholar, CMJ University, Shillong, Meghalaya, India

Abstract – Oil recovery by low salinity water flooding in secondary and tertiary modes was investigated in the present study. Cores from Berea outcrop sandstone and Minnelusa reservoir sandstone were used in the single phase and two phase experiments. Two types of Minnelusa crude oils were used in the two phase experiments. The single phase experiments provided the baseline for pH and pressure changes in the two phase experiments.

Set of experiments were performed by using low salinity brine for the tertiary waterflood recovery method where oil saturated cores were first flooded with high salinity brine to simulate the secondary recovery method. In the second set of experiments, oil saturated cores were directly flooded with the low salinity brine. Conductivity and pH analysis of effluent brines were performed in all the single phase and two phase experiments.

Increase in oil recovery with low salinity brine as the invading brine was observed in both secondary and tertiary modes (2-8% OOIP) with Berea sandstone. However, higher oil recoveries (5-8% OOIP) were observed when low salinity waterflooding was implemented as a secondary recovery method. Minnelusa reservoir cores had little to no response to low salinity brine when it was used as a tertiary recovery method. However, Minnelusa cores showed an increase in oil recovery (10-22 % OOIP) with both types of crude oils when it was used as a secondary recovery method. An increase in pH of the effluent brine was observed during the low salinity brine injection in both Minnelusa and Berea cores. However, magnitude of the pH increase was smaller with the Minnelusa cores compared to Berea cores.

The level of investigation into the mechanism of low salinity incremental production has sharply increased in the past two years. Most of the studies focus on core floods using the tertiary mode. Our work contributes systematic coupled secondary and tertiary mode experiments that offer an expanded dataset for all researchers to use in investigation of the mechanisms.

Many countries in the world contain significant heavy oil deposits. In reservoirs with viscosity over several hundred mPa□s, waterflooding is not expected to be successful due to the extremely high oil viscosity. In many smaller, thinner reservoirs or reservoirs at the conclusion of cold production, however, thermal enhanced oil recovery methods will not be economic. Waterfloods are relatively inexpensive and easy to control; therefore they will still often be employed even in high viscosity heavy oil fields. This paper presents experimental findings of waterflooding in laboratory sand packs for two high viscosity heavy oils: 4650 mPa□s and 11500 mPa□s, at varying water injection rates. The results of this work show that capillary forces, which are often neglected due to the high oil viscosity, are in fact important even in heavy oil systems. At low injection rates, water imbibition can be used to stabilize the waterflood and improve oil recovery. Waterflooding can therefore be a viable non-thermal enhanced oil recovery technology even in fields with very high oil viscosity.

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INTRODUCTION

Water flooding is still the recovery process responsible for most of the oil production by secondary recovery. Water injected into the reservoir displaces almost all of the oil except the residual oil saturation from the portions of the reservoir contacted or swept by water. The fraction of oil displaced from a contacted volume is known as the displacement efficiency and depends on the relative permeability characteristics of the rock as well as the viscosities of the displacing and displaced fluids. The extent to which a reservoir is swept by a displacing fluid is separated into areal and vertical sweep efficiencies. The areal sweep efficiency accounts for the nonlinearity of the flow patterns between injection and production wells. The vertical sweep efficiency or coverage is caused by the heterogeneity of the reservoir, i.e., variation of horizontal permeability in the vertical direction. The displacing fluid tends to move faster in zones with higher permeabilities, resulting in earlier breakthrough into producing wells. Both areal and vertical sweep efficiencies are highly dependent on the mobility ratio of the displacement process and depend on the volume of the injected fluid expressed in pore volumes. The vertical sweep efficiency, however, is mainly dependent on the permeability distribution in the producing layer. Because of the variation in the depositional environments, reservoir rocks usually exhibit random variations in their petrophysical properties. Porosity is usually found to have a normal distribution, while the permeability has a log-normal distribution. The log-normal distribution of permeability is characterized by two parameters: the mean permeability Km and the standard deviation sk . The standard deviation sk can also be expressed in terms of the DP variation coefficient VDP. It may also be related to the Lorenz coefficient L.

The methods available in the literature to predict the waterflooding performance of stratified reservoirs can be grouped into two categories depending on the assumption of communication or no communication between the different layers. The method of DP1 is the basis for performance prediction in noncommunicating stratified reservoirs. In addition to the basic equations presented in their work, they also presented correlations of the vertical coverage for log-normal permeability distributions in terms of mobility ratio and permeability variation coefficient at different values of the water-oil ratio. Also presented in this paper is a correlation of actual recovery factor vs. vertical coverage, initial water saturation, and water-oil ratio. This correlation was based on experimental runs performed on core plugs with permeability distributions determined by measuring the permeability at different locations on the core with a minipermeameter. Johnson2 later on combined the theoretical charts based on DP equations with the experimental correlation chart into a group of correlation charts from which the recovery factor at given values of water-oil ratio can be calculated directly without first computing the vertical coverage.

Mobarek3 found discrepancies between results obtained by this method and results obtained using a numerical model. Muskat4 presented analytical solution for waterflooding performance of stratified systems with linear and exponential permeability distributions. Reznik et al.5 derived expressions for the variation of pressure drop or injection rate as function of injection time for the DP model.

Prediction of waterflooding performance for communicating reservoirs was presented by Hiatt.6 This model assumes instantaneous crossflow between layers to keep the pressure gradient the same in all layers at any distance. Warren and Casgrove7 applied the Hiatt model to a system with log-normal permeability distribution and normal porosity distribution. Their method is semigraphical, semianalytical since they obtain values from plots of permeability and formation capacity distributions on probability graphs. Hearn8 used the same model of Hiatt to develop expressions for pseudorelative permeabilities that can be used in numerical reservoir simulation to reduce a three-dimensional model to a two-dimensional areal model with average ~pseudo! functions for the vertical direction. El-Khatib9 extended the work of Hiatt to account for variable rock properties other than the absolute permeability.

He also presented equations for the variation of the injectivity ratio with injection time and compared performance of communicating and noncommunicating systems.

Waterflooding has been used since late 1800’s as an oil recovery method after primary depletion of an oil reservoir. In earlier days, the amount of water injected was considered as the most important factor in recovering oil using a waterflood. However, researchers had later pointed out that the composition and quality of the water are more important factors in obtaining optimizing oil recovery by waterflooding. The injected brine in the earlier waterfloods was the formation brine. Increase in oil recovery by decrease in injected water salinity was first observed by Bernard (1967) in an experimental study. Morrow and coworkers (Jadhunanadan and Morrow, 1995; Tang and Morrow, 1997; Morrow et al., 1998; Tang and Morrow, 1999a; Tang and Morrow, 1999b) broadly studied the effect of low salinity brine injection on oil recovery in the mid to late 90’s. BP then investigated the effect of low salinity brine injection on oil recovery in field scale (Webb et al., 2003). Since then many researchers have studied low salinity brine injection because it is one of the most inexpensive and environmentally friendly oil recovery methods (Lager et al., 2008; Patil et al., 2008; Pu et al., 2008; Webb et al., 2008; Alotaibi and Nasr_el_Din, 2009; Boussour et al., 2009; Cissokho et al., 2009; Austad et al., 2010; Kumar et al., 2010; Rivet et al., 2010; Gamage and Thyne, 2011). There are other advantages to injection of low salinity brine, such as reduction in scaling and corrosion of the equipment used in the field (Collins, 2011). This method can also reduce the potential for reservoir souring. All of these factors contribute in a positive manner to project economics.

Many studies on low salinity brine injection confirm that this method can improve oil recovery by 2-42% depending on the brine composition, crude oil composition and rock type. However, there are some laboratory and field studies which do not show any increase in oil recovery by low salinity brine injection. Some researchers have studied the effect of oil recovery by low salinity brine injection in secondary or tertiary recovery modes (Ashraf, 2010). In the following study, we performed a comparison of oil recovery by low salinity brine injection in secondary and tertiary recovery modes for outcrop and reservoir sandstones.

Waterflooding involves injection of water into a reservoir to sweep additional oil to producing wells. Good candidate reservoirs include those with:

- Weak water drives
- Solution gas drives
- Undersaturated reservoirs Waterflooding is the oldest and most successful secondary recovery process, dating to before 1900. A successful waterflood requires integration of several technology capabilities.
- Reservoir management to understand resource potential –both oil in place and recovery.
- Timing of project implementation is crucial to ensure recovery is maximized.
- Injection water compatibility with both reservoir rock and formation waters must be understood. (Marathon patented technology for sulfate ion removal when scaling problems arise.)
- Accurate geologic and reservoir characterization ensures injection locations and rates are optimized to maximize sweep efficiencies and oil recovery.
- Continuous surveillance to monitor performance. (Marathon patented gel technology for conformance treatments when injection breakthroughs occur.)

Water flood is the term used to describe the increase in oil recovery by injecting water into an oil-producing reservoir. When gas is injected, it is not referred to as gas flood, but instead is referred to as pressure maintenance.

The term injection well is a general term that means that either water or gas is injected into a well. Water disposal is a term used when water does not enter an oil-producing zone. Water Injection and Water Flood : In the early years of experimenting with enhanced recovery, water flood was introduced. This secondary recovery practice solved a major problem of well operation. It provided a way to dispose of undesirable water without the water being used to stabilize firewalls around tank batteries, control vegetation growth, and water lease roads. At the same time, the water raised production of the available oil in the reservoir.

Water flood remains a keystone to many methods of enhanced recovery. It is an excellent second-stage recovery technique and is also a major factor in slugging and blending and extends deeply into many tertiary recovery procedures throughout the producing life of the reservoir. One problem with water flood is that it is difficult to push water through the formation as a vertical wall—that is, the water will spread out in the formation rather than move through it evenly. Gravity pulls the leading edge of the water down and causes it to move downward as it progresses through the reservoir. It can travel under the oil and leave a large amount of oil behind.

THEORY

Waterflooding of oil reservoirs is a well-recognized technique for oil recovery after primary production. In conventional oil, waterflooding theory has been well documented1. The inherent assumption in conventional oil waterflooding theory is a similarity in viscosity between oil and water2,3. In heavy oil applications this is not the case, thus even concepts like oil/water relative permeability do not have the same meaning in heavy oil reservoirs. However, practitioners often still attempt to apply the same theoretical understanding to their fields.

There has been some limited experience documented for waterfloods in heavy oil reservoirs4-7, but in general the mechanism of viscous oil recovery by waterflooding has not been explored. Waterflood recoveries are known to be low for high viscosity heavy oil, due to the adverse mobility ratio between oil and injected water. Despite the presumed inefficiency of this process, in many heavy oil fields waterflooding is still commonly applied since it is relatively inexpensive and field operators have years of experience designing and controlling waterfloods.

At the end of a conventional oil waterflood, residual oil is left in place due to reservoir heterogeneities or capillary trapping. In laboratory core flood experiments, capillary bypassing is the main mechanism responsible for trapping of oil2,8. This is not the case in heavy oil. In heavy oil reservoirs, the high oil viscosity (and hence the poor mobility ratio between displacing and displaced fluids) is the main cause for oil bypassing and residual oil at the end of the waterflood.

Previous investigations have therefore focused on the oil/water mobility ratio, and how it relates to viscous fingering or instability of the displacing water front.

EXPERIMENTAL DESIGN

Crude oils from two Minnelusa fields, Raven Creek (RC) and Gibbs (GBS), were used this study. The Raven Creek reservoir bottomhole temperature is about 75C while Gibbs is about 68C. The two oils represent the lighter end of the range of oil gravities in Minnelusa fields. Crude oil was centrifuged at 6000 rpm for 2 hours and filtered to remove water and sediments, vacuumed for 4 hours to remove the light ends. This process can increase water wetness in the system benefiting the low-salinity effect (Tang and Morrow 1997). Crude oil was stored in amber colored bottles in the dark to avoid photochemical dissociation of the crude oil components.

Outcrop Berea sandstones, and reservoir cores from the Minnelusa Donkey Creek Field were used in the core flooding experiments. C ore plugs (1.5 x 3.0 inches) were drilled from either slabbed core or a block (Berea) and dried in the oven at 100^0C for 48 hours. The outside of the core plugs were cleaned by a brush before measuring air permeability. Permeability of the cores was measured using nitrogen gas flow (confining pressure, 500 psi). Core plugs were stored in a desiccator until use. Reservoir core plugs were drilled from a Donkey Creek Field Minnelusa whole core. The core plugs were cleaned by a soxhlet for a week with toluene and acetone. Finally, core plugs were dried in an oven at 100^0C for 48 hours. Air permeability was measured (confining pressure, 500 psi) and mineral compositions were determined by XRD and thin section petrography. Berea core plugs are quartz rich sandstones with minor amount of calsite and dolamate. Minnelusa lithology is quartz-rich sandstone with minor amounts of anhydrite and dolomite. There are very small amounts of clay, identified in XRD as illite.

Synthetic brine representing average Minnelusa formation water composition was made from ACS grade chemicals and distilled water. Synthetic brines were vacuumed for two hours to remove dissolved gas before the experiments.

Both single and two phase experiments were performed. The single phase experiments provide a baseline to evaluate the two phase experiments. First, core plugs were saturated with formation brine under vacuum then aged at room temperature for 7 days. Porosity was calculated by subtracting dry weight of the core from the weight of the brine saturated core. Next, the core plug was mounted in a Hassler core holder and high-salinity brine (2-3 PV) was injected to establish a constant pressure drop across the core. Pressure drop at different flow rates (0.1, 0.2, 0.3 and 0.4 ml/min) was used to calculate the brine permeability (Kb). In the single phase experiments brine saturated cores were flooded directly with the high salinity brine at 0.2 ml/min for more than 10 pore volumes. During the high saline brine injection pressure drop across the core was measured continuously. Effluent brine was collected in 8 ml samples, pH and the conductivity of the collected samples were measured immediately.

For the tertiary mode two phase experiments, cores were aged with brine, then brine permeability was measured by the same procedure used in single phase experiments. To establish the initial water saturation (Swi) the core plug was flooded with the crude oil (5 PV) (Tang and Morrow, 1997). Volume of brine displaced by the oil was used to calculate the original oil in place (OOIP) and Swi. Oil permeability was measured at Swi by using the same method as brine permeability. Cores were removed from the core holder and placed in an aging cell for 10 days at 600C (Tang and Morrow, 1997). After aging, core plugs were re-mounted in the Hassler core holder and flooded with fresh crude oil for about 5 PV (same direction used to establish the Swi). After preparation, core plugs are flooded with the high-salinity brine (formation brine) at 0.2 ml/min for about 10 PV. Pressure drop across the core was measured continuously during the experiment; oil production was measured at set time intervals. Effluent brine was collected in 8 ml samples by using a fraction collector. Therefore, the discrete samples represent an average of dissolved properties for the sampled interval.

The sand used in all experiments was Lane Mountain 70 sand. The sand was wet packed with methanol. After the sand was packed, it was CT (Computerized Tomography) scanned to determine that the pack was uniform. The sandpack was then drained and dried overnight with compressed air, and nitrogen was used to remove any residual methanol. The sandpack was then scanned again to ensure that it was dry. Once it was established that it was dried, gas expansion was performed on the sandpack to determine its porosity. The sandpack was then left under vacuum for approximately a day, after which brine saturation and brine permeability were determined. The sandpack was then flooded with oil until irreducible water saturation is reached. During this stage, the pressure at the inlet and outlet of the sandpack was monitored. The sandpack was left undisturbed for about a day to allow equilibrium to be reached. Waterfloods were then carried out at the specified flow rates. Again, the inlet and outlet pressures were recorded periodically. The products of the waterflood was also collected and analyzed for oil and water content with low-field NMR and separation with toluene. All floods were performed at ambient temperature (23°C) and with applied overburden on the sand.

WATER INJECTION AND WATER FLOOD

In the early years of experimenting with enhanced recovery, water flood was introduced. This secondary recovery practice solved a major problem of well operation. It provided a way to dispose of undesirable water without the water being used to stabilize firewalls around tank batteries, control vegetation growth, and water lease roads. At the same time, the water raised production of the available oil in the reservoir.

Water flood remains a keystone to many methods of enhanced recovery. It is an excellent second-stage recovery technique and is also a major factor in slugging and blending and extends deeply into many tertiary recovery procedures throughout the producing life of the reservoir.

One problem with water flood is that it is difficult to push water through the formation as a vertical wall—that is, the water will spread out in the formation rather than move through it evenly. Gravity pulls the leading edge of the water down and causes it to move downward as it progresses through the reservoir. It can travel under the oil and leave a large amount of oil behind.

Nevertheless, water continues to be one of the best enhanced recovery tools available. Water flood should be carefully designed and properly installed because it will probably be in place for the life of the well or until equipment needs major changes.

PROBABILISTIC MODELING

A parametric simulation study was performed using experimental design to calculate increment oil recovery due to water injection and to identify the influence of parameters on recovery factor. The experimental design workflow is summarized below:

- Define uncertainty parameters and ranges.
- Set-up the experimental design matrix.
- Run the simulation cases defined in the matrix.
- Perform a multivariate regression to develop a linear relationship between recovery factor and uncertainty parameters (called the "proxy" equation).
- Generate an "S-curve" for recovery factor using a proxy equation.

A total of eleven uncertainty parameters were used in the parametric study. The parameters and range of uncertainty for each are detailed.

Both static and dynamic parameters were considered. The geologic uncertainty parameters incorporated into the static models include: structural dip, faulting, facies, aquifer size, and reservoir parameters

(absolute permeability and heterogeneity). Dynamic uncertainty parameters include: fluid properties, water injection variables (timing and injection rates), and relative permeability variables (residual oil saturation and endpoints). Two static models were constructed based on the stratigraphy and reservoir properties from a thick-bedded middle Miocene reservoir (e.g., Tahiti Field) and a thinner-bedded Paleocene. Geocellular and dynamic simulation models were built with 200 x 200 ft cells having a thickness of 5 ft. Simple depofacies consisting of sheet, distal sheet, channel and shale were populated, and reservoir properties were distributed in these depofacies. Upscaled depofacies and properties are compared to the wireline logs, and a cross section showing injector and producer well locations in the dynamic model. Permeability distributions were generated for three different Dykstra- Parson's coefficients; 0.27, 0.6, and 0.8. Porositypermeability cross-plots. Three different fluids were considered with GOR (API) of 1,800 scf/stb (35° API), 1,100 scf/stb (30°API), and 500 scf/stb (27° API).

Experimental design matrices were generated for both primary and water flood scenarios, based on the eleven uncertainty parameters. Eighteen primary cases and twenty-seven water flood cases were run. Proxy equations for both primary and water flood oil recovery were generated from the simulation results.

Cumulative probability functions, "S-curves," of oil recovery for both primary and water flood were calculated from the proxy equations using Monte-Carlo simulation. P50 oil recovery is 30% for primary and 37% for water flood, yielding incremental recovery of 7% of OOIP. As expected, incremental recovery for water flood is larger when primary recovery is low and lower when primary recovery is high. It is important to focus on incremental oil recovery rather than absolute recovery factor due to the modeling of a single producer-injector well pair.

SUMMARY & CONCLUSION

An analytical solution is developed for waterflooding performance of layered reservoirs with a log-normal permeability distribution with complete crossflow between layers. The permeability distribution is characterized by the Dykstra-Parsons ~DP! variation coefficient VDP or the standard deviation of the distribution sk . The performance is expressed in terms of vertical coverage as function of the producing water-oil ratio. Also an expression for the dimensionless time ~pore volumes of injected water! at a given water-oil ratio is derived. Expressions are also derived for pseudorelative permeability functions and fractional flow curves that can be used in reservoir simulation. Correlation charts are also presented to enable graphical determination of the performance. The variables are combined in such a way that a single chart is constructed for the entire range of water-oil ratio, mobility ratio and permeability variation.

Analogy to the Buckley-Leverett ~BL! multiple-valued saturation profile is found to occur at low mobility ratios (M,1) where a multiple-valued displacement front is formed. A procedure similar to the BL discontinuity is suggested to handle this situation.

Successive layers with different permeabilities are allowed to move with the same velocity resulting in a single-valued profile with a discontinuity. No such behavior is observed for mobility ratios greater than unity. A criterion for the minimum mobility ratio at which this behavior occurs is presented as a function of the variation coefficient.

Single phase core flooding experiments were performed with the Berea and Minnelusa core plugs. The experiment with Berea core plug shows a pH increase from 7.7 to 8.8 during the low saline brine injection. Fines were observed in the effluent brine during the low salinity brine flood. Pressure across the core increased for about 4-5 pore volumes during the low salinity brine flood then declined. The single phase experiment with Minnelusa core plug shows a smaller increase in pH during the low salinity brine injection. Fines were not observed in the single phase Minnelusa core flooding experiment.

Secondary mode and tertiary mode core flooding experiments were performed using two Minnelusa formation crude oils and two rock types (Minnelusa and Berea). Incremental oil recovery from low-salinity brine injection was observed in most of the tertiary mode experiments. The incremental recovery is coincident with the decrease in salinity and increase in pH in Berea sandstone core flooding experiments. However, similar pH increases was not observed during the low salinity brine injection in Minnelusa core flooding (single and two phase) experiments. Fines were observed in the effluent of some Berea core flooding experiments.

Among each rock type and oil combination, secondary mode experiments produced more oil than the tertiary mode experiments. In the experiments with RC crude oil and Berea core plugs secondary mode experiments produced about 6% more oil than the tertiary mode experiments. Core flooding experiments of Berea core plugs and GBS oil shows about 8% higher oil recovery in the secondary mode experiments with compared to tertiary mode experiments. The highest oil recovery (68%) was observed in the secondary mode experiments with RC oil and Minnelusa rock system. In the secondary mode experiment with Minnelusa rock and RC oil system, about 22% more oil was produced than the tertiary mode experiment. In the experiments with Minnelusa rock and GBS oil, secondary mode low-salinity flooding produced about 10% more than the tertiary mode flooding.

A set of ambient temperature laboratory core floods was performed in order to identify the mechanisms responsible for heavy oil recovery under waterflooding. Tests were performed for two different heavy oils, at varying water injection rates. The parameters that were investigated were the influence of viscous and capillary forces on oil recovery, and explain the mechanisms for oil recovery after water breakthrough.

The significance of capillary pressure was investigated, in order to explain the reason for improved oil recovery at low rates. The oil production rates were normalized to the lowest injection rate, which removes the effect of viscous flow. It was then observed that at low injection rates, the normalized oil rate was proportionally higher than the oil flow rates at higher water injection rates. This indicates that capillary forces are significant even during flow of viscous heavy oil. By properly controlling a heavy oil waterflood, the ratio of oil/water flow rates can be improved by as much as one order of magnitude.

A secondary goal of this work was to be able to predict the recovery from a heavy oil waterflood. A correlation was observed between recovery and instability number, and a simple empirical model was developed to predict waterflood recovery based on only the injection rate, oil viscosity and sand permeability. This correlation, developed over a wide range of oils and sand permeability, appears to be able to predict the recovery from waterflooding under unstable conditions.

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