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**SURFACTANT-POLYMER INTERACTION FOR IMPROVED OIL
RECOVERY**

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By:
Jorge Gabitto, Prairie View A&M University
Kishore K. Mohanty, University of Houston

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Prairie View A&M University
Prairie View, Texas

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Surfactant-Polymer Interaction for Improved Oil Recovery

By
Jorge Gabitto
Kishore K. Mohanty

January 2002

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Purna Halder, Project Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by
Prairie View A&M University
P.O. Box 397
Prairie View, TX 77446

**"SURFACTANT - POLYMER INTERACTION FOR IMPROVED OIL
RECOVERY"**

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“SURFACTANT-POLYMER INTERACTION IN ENHANCED OIL RECOVERY”

ABSTRACT

The goal of this research is to use the interaction between a surfactant and a polymer for efficient displacement of tertiary oil by improving slug integrity, oil solubility in the displacing fluid and mobility control. Surfactant-polymer flooding has been shown to be highly effective in laboratory-scale linear floods. The focus of this proposal is to **design an inexpensive surfactant-polymer mixture that can efficiently recover tertiary oil** by avoiding surfactant slug degradation and viscous/heterogeneity fingering.

A mixture comprising a "pseudo oil" with appropriate surfactant and polymer has been selected to study micellar-polymer chemical flooding. The physical properties and phase behavior of this system have been determined. A surfactant-polymer slug has been designed to achieve high efficiency recovery by improving phase behavior and mobility control. Recovery experiments have been performed on linear cores and a quarter 5-spot. The same recovery experiments have been simulated using a commercially available simulator (UTCHEM). Good agreement between experimental data and simulation results has been achieved. Adequate salinity control improves the oil recovery efficiency. A salinity gradient chemical flood maximizes the oil recovery.

"SURFACTANT-POLYMER INTERACTION IN ENHANCED OIL RECOVERY"

EXECUTIVE SUMMARY

A research project is proposed to develop new polymer/surfactant blends for use in oil field production and improved oil recovery operations. These operations include fingering reduction and improved oil recovery by polymer-surfactant flooding.

The group carrying out this project is comprised of researchers from the Chemical Engineering Department at Prairie View A&M University (PVAMU), a Historical Black College and University (HBCU), from the Chemical Engineering Department at the University of Houston (UH), and BDM Petroleum Technologies (BDMPT). The joint partnership offers unique advantages obtained from support to an HBCU of a major academic institution and a private company using advanced technologies and research facilities.

The research group at BDMPT reports experimental data about suitable oil-surfactant-polymer systems and their properties. The research group at UH carries out flow experiments using the aforementioned systems. The group at PVAMU computes stability phase maps and simulates the experiments at UH.

A vast amount of proven domestic oil deposit is stranded in reservoirs too shallow for miscible flooding, yet this oil is too light for thermal techniques. Surfactant-polymer flooding is the only method to unlock this vast resource. The integrity of the surfactant slug is critical to the economic success of a surfactant-polymer flood. This research supplies experimental data, phase maps and mechanistic principles for optimum surfactant-polymer slug design.

"SURFACTANT - POLYMER INTERACTION FOR IMPROVED OIL RECOVERY"

INTRODUCTION

More than 224 billion barrels of immobile oil remain in U. S. domestic reservoirs. For a number of reservoirs, chemical IOR methods may be the only viable method for significantly reducing oil saturation in the field. The key to success of any chemical IOR method depends not only on the effectiveness of chemicals to mobilize residual crude oil, but also on ensuring that the treatments actually contact oil through appropriate use of profile modification treatments and on the ability of mobility control agents to move the oil to the production wells. New research is needed, especially in chemical flooding methods, to reduce the operation cost. Chemical IOR systems include surfactants, polymers, alkali agents, or combinations thereof. Surfactants and alkali agents can lower interfacial tension (IFT) between oil and water, thereby mobilizing the immobile oil. Alkali agents can also act to reduce surfactant losses from precipitation and adsorption. Polymers are used to increase the viscosity of aqueous solutions and maintain mobility control. Other types of polymer formulations are used to block high permeability zones and divert injection fluids to lower permeability, unswept zones.

The goal of the proposed research is to use the interaction between a surfactant and a polymer for efficient displacement of tertiary oil by improving slug integrity, oil solubility in the slug and mobility control. The mobility ratio across surfactant - oil bank flood front is often unfavorable, but can be stabilized by the addition of polymers.

This research program has been divided in two parts. A theoretical part, and an experimental program. The theoretical program involves two different goals: First, we would like to study the stability of the system to fingering in order to provide practitioners with tools to design surfactant-polymer processes with improved recovery. This goal is achieved using linear stability analysis to study the conditions that will determine the onset of fingering as a function of fluid properties and operating conditions. A custom made simulator described elsewhere will be used to test the results of the linear analysis. Second, we want to be able to simulate the experiments in order to understand the different mechanisms involved. A detailed description of the efforts made on this regard is presented after the stability section.

The experimental program involves linear displacements in cylindrical cores and quarter 5-spot experiments. These experiments have been simulated using the UTCHEM commercial simulator.

This project has been carried out by a team involving, Dr. Kishore Mohanty from the University of Houston (UH), Dr. Jorge Gabitto from Prairie View A&M University (PVAMU) and Dr. Rebecca Bryant from BDM Petroleum Technologies (BDM-PT), a private company.

TECHNICAL INTRODUCTION

BACKGROUND

For a big number of reservoirs, chemical EOR methods may be the only viable methods for significantly reducing oil saturation in the field.

Capillary forces cause large quantities of oil to be left behind after waterflooding of an oil reservoir. Capillary forces arise from the interfacial tension (IFT) between the oil and water phases that resist externally applied viscous forces and causes the injected water to bypass the resident oil. The predominant mechanism to recover this oil is lowering the IFT through the addition of suitable chemicals (surfactants). Lower interfacial forces recover additional oil by reducing these capillary forces. This trapping of the resident oil can be expressed as a competition between viscous forces, which mobilize the oil, and capillary forces, that trap the oil.

In practice surfactant injection alone, can not achieve sufficient recovery due to several problems, fingering, adsorption, surfactant-soil interactions, etc. Therefore, a more complex process involving different steps is required to fully realize this technique potential. This recovery process receives different names, but throughout this work we will use the term micellar-polymer flooding (MP) following Lake¹.

Figure 1 (taken from Lake¹), shows an idealized version of an MP flooding sequence. The process is applied in the drive mode. The process consists of:

Preflush. A volume of brine to lower salinity is added first. Preflushes range from 0 to 100% pore volume (PV). Sometimes an agent is added to lessen the surfactant retention².

MP slug. The main surfactant, cosurfactants, and other chemicals are added later. Slug volumes range from 5 to 20% PV.

Mobility buffer. This fluid is a dilute solution of a water-soluble polymer whose purpose is to drive the MP slug and banked-up fluids towards the production wells. The buffer volumes range from 0 to 100% PV.

Mobility buffer taper. This is a volume of brine that contains dilute polymer added to produce a gradual change in polymer concentration from the mobility buffer concentration to zero.

Chase water. This fluid is injected to reduce the cost of continuous injection of polymer.

Adequate design of all these different steps requires careful consideration of phase behavior and physical properties of all the chemicals used. A successful MP flood must achieve three things for effective oil recovery².

(1). The MP slug should propagate at optimal conditions, especially salinity.

(2). Surfactant concentration should be big enough so that some of it is unretained by permeable surfaces.

(3). The active surfactant should sweep a large portion of the reservoir without excessive dissipation due to dispersion or channeling.

One of the most important variables to achieve the aforementioned conditions is salinity. It will later be shown that salinity significantly influence phase behavior and physical properties in an MP process. Lowering the resident salinity is the main purpose of the preflush step. A successful preflush will permit an MP slug to displace oil wherever it goes and will reduce retention and loss of surfactant activity. Several salinity gradient design techniques have been proposed^{3,4}. The concept is to dynamically lower the resident salinity to optimal by injecting an underoptimal mobility buffer salinity. Pope et al.⁵ found salinity to be the most important variable controlling the oil recovery process in a series of laboratory experiments.

Mobility control of the MP slug is another critical factor in achieving a successful recovery. Field slugs are relatively small and do not tolerate even a small amount of fingering. Therefore, a slug less mobile than the oil bank it is displacing is sought. Polymer should be added to the MP slug to achieve this goal. The spike portion of the mobility buffer must have a mobility equal or less than the slug. Since the slug mobility also depends upon the oil concentration, the slug and mobility buffer should be designed together.

SURFACTANT-BRINE-OIL PHASE BEHAVIOR

In order to understand the bases for a successful MP process design a simplified system phase behavior is presented. Surfactant-brine-oil is conventionally illustrated on a ternary diagram¹. The top apex of the diagram represents the surfactant pseudo-component, the lower left represents the brine and the lower right represents oil (see Figure 2).

Brine salinity strongly affects the phase behavior. Figure 3 shows a sequence of phase diagrams as salinity is increased. The phase behavior described here has been taken from Nelson and Pope⁶. At low brine salinity, a typical surfactant will exhibit good aqueous-phase solubility and poor oil phase solubility. Thus an overall composition near the brine-oil boundary will split into two phases: an excess almost pure oil phase and a micro-emulsion phase that contains brine, surfactant and solubilized oil. This type of phase behavior is called Winsor type I or type II(-) system. We adopt the type II(-) terminology in this work. The two phase region is enclosed by a binodal curve. Equilibrium two phase compositions are linked by tie-lines. A special point (plait) denotes the composition at which the concentrations in both phases coincide. Above the binodal curve we have only one phase. The tie-lines in II(-) behavior have negative slopes.

For high brine salinities electrostatic forces reduce the surfactant's solubility in the aqueous solution. Therefore, an overall composition, within the two-phase region, will split into an excess brine phase and a micro-emulsion phase that contains most of the surfactant and some solubilized brine. The phase environment is called a Winsor type II

or a type II(+) system. These behaviors constitute extreme cases. For a range of intermediate salinities a third surfactant rich phase can appear. An overall composition within the three-phase region separates into excesses oil and water rich phases and into a micro-emulsion phase whose composition is represented by an invariant point. This phase behavior is called a Winsor III type or a type III system. To the upper right and left of the three-phase region there are type II(-) and II(+) lobes wherein two phases will form as before. Type III behavior starts after a critical lower effective salinity (C_{Sel}) is reached⁶. The behavior disappears when critical upper effective salinity (C_{Seu}) is reached⁶. Over the type III salinity range there is migration of the invariant concentration point M from near the oil apex to near the brine apex. As the migration takes place the surfactant concentration in the microemulsion reaches a minimum when the oil-brine ratio at the invariant point becomes 1. The migration of the invariant point implies essentially unlimited solubility of oil and brine in a single phase. Several physical properties take extreme values at this critical point. This change in system's properties is used to determine optimal conditions for the recovery process. For example, there is a clear relationship between interfacial tension and phase behavior. The optimal salinity point can be determined by plotting interfacial tensions in the oil rich and aqueous rich phases versus salinity⁷. Figure 6 illustrates this behavior. The optimal salinity determined using interfacial tension agrees well with optimal salinities determined using other properties such as, solubilization ratios and oil recovery results. The optimal salinity corresponds roughly to the salinity where oil recovery from a core is maximum¹. Optimal salinities depend upon the nature of the surfactant and the brine pseudo-components. Adding co-surfactants to the MP slug normally increases the optimal IFT. The notion of optimal salinity is directly related to the phase behavior of MP systems. Even properties such as, retention, are functions of salinity, co-surfactant concentration, and temperature. This observation leads to the speculation that all MP properties correlate to optimal salinity¹.

STABILITY ANALYSIS

THEORETICAL DERIVATIONS

A quarter five-spot system is modeled. The pressures at the production and injection wells are assumed to be constant and functions of the mobilities and flow rates. The equations describing this system are,

$$\frac{\partial}{\partial t}(\phi S_k) = \nabla \cdot [\lambda_k \nabla \Phi_k] + Q_k, k=w, nw \quad (1)$$

S is the phase saturation, λ_k is the phase mobility, Q_k is the rate of injection of phase k into the system. We use the fact that the saturations are related through

$$S_w + S_{nw} = 1 \quad (2),$$

and the capillary pressure is defined by,

$$P_c = p_{nw} - p_w \quad (3).$$

The gravity potential is defined by,

$$\Phi_k = p_k - \gamma_k Z, k=w, nw \quad (4),$$

where γ_k is the k phase specific gravity and Z is the vertical depth of the reservoir.

By derivation with respect to time of eqn. (2) we get,

$$\frac{\partial S_w}{\partial t} = - \frac{\partial S_{nw}}{\partial t} \quad (5).$$

Therefore by replacing eqn. (5) into eqns. (1) and rearranging using eqns. (3) and (4) we get,

$$\frac{\partial}{\partial t}(\phi S_w) = \nabla \cdot [\lambda_w \nabla \Phi_w] + Q_w \quad (6),$$

$$0 = \nabla \cdot [\lambda_{rt} \nabla \Phi_w] + \nabla \cdot [\lambda_{mw} \nabla P_c] + \nabla \cdot [\lambda_{mw} \nabla Z (\rho_{nw} - \rho_w)] + Q_w + Q_{nw}, \quad (7),$$

ρ_k is the wetting and non-wetting phase density. The following equations are reduced to dimensionless form by using:

$$\Phi_k^* = \frac{\Phi_k}{\Phi_k^i - \Phi_k^o}, x^* = \frac{x}{L_x}, y^* = \frac{y}{L_y}, P_c^* = \frac{P_c}{\Phi_k^i - \Phi_k^o}, \tau = \frac{t \sigma_{wnw}}{\mu_w L_x},$$

and defining the following dimensionless numbers,

$$N_{\text{cap}} = \frac{K (\Phi_k^i - \Phi_k^o)}{L_x \sigma_{\text{wnw}}}, N_{\text{Bond}} = \frac{K (\rho_{\text{nw}} - \rho_w) g}{\sigma_{\text{wnw}}} \quad (8),$$

where, Φ_k^o and Φ_k^i are the potentials at the injection and production wells assumed to remain constant during the experiments, σ_{wnw} is the surface tension between wetting and non-wetting phases, and μ_k is the k phase viscosity.

$$0 = N_{\text{cap}} \nabla^* \cdot [k_{\text{rt}} \nabla^* \Phi_w^*] + N_{\text{cap}} \frac{\mu_w}{\mu_{\text{nw}}} \nabla^* \cdot [k_{\text{rnw}} \nabla^* P_c^*] + N_{\text{Bond}} \nabla^* \cdot [k_{\text{rnw}} \nabla^* Z] + Q_w^* + Q_{\text{nw}}^*, \quad (9),$$

$$\frac{\partial}{\partial \tau} (\phi S_w) = N_{\text{cap}} \nabla^* \cdot [k_{\text{rw}} \nabla^* \Phi_w^*] + Q_w^* \quad (10),$$

here k_k is the relative permeability of phase k (function of S_w).

Equations (9) and (10) are the equations used throughout these research. Four parameters appear in these equations, the Bond and capillary numbers, a viscosity ratio and a geometric ratio for the quarter five-spot model. These parameters will control the fingering behavior of our system for constant relative permeability.

LINEAR STABILITY ANALYSIS

Linear stability analysis will provide information for the onset of fingering from a given base state. While several authors reported stability limits for fingering^(8,9,10,11) none of them calculated phase diagrams. Chang and Slaterry¹² recognized the importance of starting a theoretical stability study from a linear stability analysis. These authors studied miscible displacements.

From now on we are going to eliminate the * from all the variables in the understanding that every variable is dimensionless. We propose that the wetting phase potential (Φ_w) varies from a base state ($\underline{\Phi}_w$) as,

$$\Phi_w = (\underline{\Phi}_w) + \varepsilon G(x,y) \quad (11),$$

where ε is a first order perturbation parameter and $G(x,y)$ contains the functional departure from the base state. Similarly we can define,

$$S_w = \underline{S}_w + \varepsilon H(x,y) \quad (12),$$

$$k_{rt} = \underline{k}_{rt} + \varepsilon \frac{\partial k_{rt}}{\partial S_w} = \underline{k}_{rt} + \varepsilon H(x,y) k'_{rt} \quad (13),$$

where k'_{rt} is the derivative of k_{rt} with S_w . We also define,

$$k_{rw} = \underline{k}_{rw} + \varepsilon \frac{\partial k_{rt}}{\partial S_w} = \underline{k}_{rt} + \varepsilon H(x,y) k'_{rw} \quad (14),$$

$$k_{rw} = \underline{k}_{rw} + \varepsilon H(x,y) k'_{rw} \quad (15),$$

$$P_c = \underline{P}_c + \varepsilon H(x,y) P'_c \quad (16).$$

We apply eqns. (11) through (16) into equations (9) and (10). We use the fact that the base state is also a solution of eqns. (9) and (10) to obtain identical equations to (9) and (10) but in base state variables,

$$0 = N_{cap} \nabla \cdot [\underline{k}_{rt} \nabla \underline{\Phi}_w] + N_{cap} \frac{\mu_w}{\mu_{nw}} \nabla \cdot [\underline{k}_{rw} \nabla \underline{P}_c] + N_{Bond} \nabla \cdot [\underline{k}_{nw} \nabla Z] + Q_w + Q_{nw} \quad (17),$$

$$\frac{\partial}{\partial t}(\phi S_w) = N_{cap} \nabla \cdot [\underline{k}_{rw} \nabla \underline{\Phi}_w^*] + Q_w \quad (18).$$

We apply eqns. (11) through (16) into equations (9) and (10), and then subtract eqns. (17) and (18) to get,

$$0 = A_1 \nabla^2 G + B_1 \frac{\partial G}{\partial x} + C_1 \frac{\partial G}{\partial y} + D_1 \nabla^2 H + E_1 \frac{\partial H}{\partial x} + F_1 \frac{\partial H}{\partial y} + G_1 H \quad (19)$$

$$\frac{\partial}{\partial t}(H) = A_2 \nabla^2 G + B_2 \frac{\partial G}{\partial x} + C_2 \frac{\partial G}{\partial y} + D_2 \nabla^2 H + E_2 \frac{\partial H}{\partial x} + F_2 \frac{\partial H}{\partial y} + G_2 H \quad (20),$$

where the A, B, C, etc. coefficients are functions of the four parameters, the base solution parameters and derivatives of the relative permeability coefficients with respect to S_w .

The following solution procedure has been developed,

- I). A base solution, $\underline{S}_w$ and $\underline{\Phi}_w$, for a set of base parameters is calculated.
- II). The derivatives of P_c , and the k_{rk} are calculated for different values of $\underline{S}_w$.
- III). I) and II) allow us to calculate the set of A_i , B_i , C_i , etc.

IV). The set of eqns. (19) and (20) with the coefficients calculated in III) are solved using the process reported by Farr, Gabitto, Balakotoiah and Luss¹³. This method involved discretization in x and y directions in order to transform the system into a system of ordinary differential equations. An arch length continuation procedure

(Kubicek and Marek¹⁴) is used to compute different solutions as a function of the four parameters characterizing this system.

RESULTS

The solution was implemented in one dimension only due to the difficulty associated with a full two dimensional solution. Besides the one dimension case has been extensively study (see Lake¹ for a comprehensive review), and comparison with known results could be used to validate the approach used in this work.

The base solution used in the calculations for Φ_w and S_w was,

$$\Phi_w = A x + B \quad (21),$$

$$S_w = 1 \text{ for } x < x_f \text{ and } S_w = 0 \text{ for } x > x_f \quad (22),$$

where A and B are constants calculated from analytical solution of eqn. (9), x_f is a generic point between both extremes of the domain. A computer program was developed to implement the aforementioned solution process.

A physical description of the model used here is shown in Figure 4. The complete model involves a one dimensional perturbation, $G(x)$ or $H(x)$, that will break the front homogenous advance and the possibility of gravity overdrive, given by the value of the angle α . The simplicity of the one dimension case makes the problem to be independent of the capillarity number. The Bond number captures the influence of gravity on the front stability. Mathematical derivation of the model produces another parameter, the mobility ratio (M), to come into play. Parameter M is defined as,

$$M = \frac{\lambda_w}{\lambda_{nw}} = \frac{(k_w/\mu_w)}{(k_{nw}/\mu_{nw})} \quad (23).$$

We set the angle α to 0 degrees in order to study the effect of fingering without gravity override and we compute the value of the parameter $H(x)$ along a solution branch that changes the value of the mobility ratio M (Kubicek and Marek¹⁴). The results are presented in Figure 5. We can see that $H(x)$ follows a continuous solution for the studied range of parameter M. No multiple solutions were found within the studied range. The model used in this work is based on Darcy's law, i.e., a linear approximation to the Navier-Stokes equation. Therefore, multiple solutions are precluded. The solution branch presents a turning point at the value $M=1$. The stability of the displacement front can be studied using the value of the derivative of $H(x)$ along the M solution branch. It can be seen that the derivative is negative before the turning point and is positive after. Linear stability theory predicts a stable front before the turning point and an unstable front after the turning point. Therefore, the change in stability is given by the value of M at the turning point. This value represents the physical condition that the mobility of the displacing fluid should be smaller than the mobility of the displaced fluid to prevent fingering and consequently unstable displacements and loss of sweeping efficiency (Lake¹). This result proves the soundness of the approach followed here and suggests

continuing with the solution of the full two dimensions analysis of the displacement problem. Unfortunately, the full two dimensions problems proved to be much more complicated from the mathematical point and we had to give up the work because of the impossibility of finishing it within the time limit of this research project.

EXPERIMENTAL PART

Several chemical systems were tested to determine oil recovery potential for an oil mixture designed with a viscosity of approximately 10 cp. The tests included phase behavior observations, viscosity measurements, interfacial tension measurements, and a linear oil recovery experiment. The suggested chemical system is composed of a surfactant (petroleum sulfonate), co-surfactant (2-methyl, 1-propanol), and a high molecular weight polyacrylamide polymer.

MATERIALS:

Oil. Two oil mixtures were formulated to obtain a paraffin-based oil with an approximate viscosity of 10 cp at ambient temperature. Oil 1 consisted of 68% motor oil (SAE 30 non detergent motor oil) and 32% decane. Oil 2 was 66.5% Soltrol 220 (isoparaffinic oil from Phillips Petroleum Co) and 33.5% SAE 30 motor oil. The viscosity of Oil 2 is 11.6 cp at 23 °C and 9.88 cp at 30 °C. The viscosity of Oil 1 is 9.32 cp at 30 °C and is slightly higher at ambient temperature (10.9 cp).

Surfactant/Co-surfactant. The co-surfactant used for these studies was 2-methyl, 1-propanol (isobutyl alcohol or IBA). Alcohol molecules are incorporated in surfactant micelles and change surfactant solution properties (such as viscosity, partitioning, and solubility). Two petroleum sulfonate surfactants from Witco Corporation were tested. Table 1 summarizes surfactant information. All surfactant/co-surfactant mixtures were prepared by wt%/wt% in different concentration sodium chloride solutions. The alcohol was always used at the same concentration as the surfactant.

Polymer. The polymer is a high-molecular-weight hydrolyzed polyacrylamide, Alcoflood 1275, from Allied Colloids, which is available in powder form. This polymer is anionic, and its average molecular weight is 22×10^6 dalton.

EQUIPMENT AND PROCEDURES:

Physical Properties. Viscosities were measured with a Brookfield Cone and Plate viscometer. IFTs (interfacial tension measurements) were determined with a spinning drop tensiometer.

Phase behavior of the surfactant/brine/oil system was determined by mixing equal volumes of aqueous and oil phases in tubes made from 10 cc pipets which have had the tips sealed to prevent fluid leaks. Volumes can be read to 0.1 cc from the marking on the pipets. To determine optimal salinity and the 3-phase salinity region, a series of tubes is prepared with different salt concentrations. The tubes are shaken and allowed to equilibrate. If surfactant remains in the aqueous phase after equilibration, the salinity is under optimum and is designated II(-). If the surfactant partitions into the oil phase, salinity is over optimum and is designated II(+). If three phases form (oil, brine, and middle phase), the behavior is designated III.

Oil Recovery. The idea behind the experimental program is to observe experimentally movements of surfactant-oil bank flood fronts in well-characterized cores and a quarter 5-

spot model. The displacement in a low heterogeneity core is one-dimensional when appropriate flow rate is used. The results of these experiments provide the mobility of all the fluid banks and help conform the mechanistic model in one-dimension. The floods in a quarter 5-spot model provide experimental data on movement of surfactant-oil bank in multi-dimensions. In some cases, surfactant-oil bank front will be stable and in some cases, it will be unstable. The effect of surfactant slug composition on movement of this front is studied. The interaction between the polymer mobility buffer and the surfactant slug is studied. The influence of salinity on phase behavior and oil recovery is recorded.

Core Experiments. Oil recovery experiments were conducted in a Berea sandstone core plug 1.5 in. in diameter and 9.5 in. long. Core permeability was 506 md at 100% water saturation. Porosity was 23.3%. The core was initially saturated with non damaging brine, then oil was flooded to residual water saturation, and saturated with water to residual oil saturation before conducting the chemical flood experiment. Figure 6 shows the Hassler sleeve apparatus and experimental equipment used in the oil recovery tests.

Quarter 5-Spot Apparatus. A porous medium was prepared in two different geometries: a cylindrical core and a quarter five-spot. The cylindrical core (2.54 cm diameter, 30.48 cm long) was used to determine the relative permeability of the medium. The quarter five-spot is used to conduct the immiscible floods. The quarter five-spot model consists of a porous medium approximately 41.9 cm x 41.9 cm x 2.54 cm in size. It has a thin plastic plate above the porous medium. This plate is pressurized from above to prevent channeling. The overburden pressure is kept higher than the pressure inside the porous medium. The porous medium consists of a mixture of glass beads of a specified bead radius distribution in the range of 25 to 100 mesh (0.706 - 0.15 mm). There is an injection port at each of the four corners. Two diagonally opposite corners are usually closed during most displacement experiments. Thus the model represents one quarter of the 5-spot patterns used in oil fields. The key properties of the quarter 5-spot model dimensions are listed in Table 3.

A cylindrical packed bed was used to determine relative permeabilities of the fluids used in these experiments. The relative permeability of the cylindrical porous pack is determined by the steady state method. Brine solutions and oil are injected simultaneously at different fractional flows with the total flow rate being constant. At each steady state, the pressure drop is measured by a differential pressure transducer and the saturation is estimated by material balance. Three different saturation histories can be traversed: primary drainage, imbibition and secondary drainage. Primary drainage experiments have been conducted to evaluate the level of homogeneity of the quarter five spot apparatus. Second drainage experiments were not conducted in this research.

Immiscible displacements at adverse viscosity ratios are conducted in a quarter five-spot model in both the drainage and the imbibition modes at comparable viscosity ratios and density differences. The non-wetting fluid is the injectant in the drainage model, whereas the wetting fluid is the injectant in the imbibition mode. The quarter five-spot model is first filled with brine of a given concentration. This fluid is then miscible displaced by a glycerol-water solution of high viscosity. A viscous oil is then injected to displace the water and drive the model to its residual water saturation. Then a colored low viscosity brine solution of a suitable concentration is injected to displace the viscous oil. The

fingering in this adverse viscosity, immiscible, imbibition flow is then visualized. The injection rate was 1 ml/min. in these displacements. The fluids used and their properties are listed in Table 4. The effluent composition and the pressure drop were monitored. Photographs can be taken from the top and sides of the model during experiments.

The viscosity ratio (μ_o/μ_b), the ratio of the viscous to gravity forces, and the ratio of the field-scale capillarity to viscous forces are approximately honored in this model for typical field applications. The capillary number ($10^{-7} - 10^{-5}$) is, however, not honored. The effluent is analyzed for oil, solvent and water production. After finishing one displacement experiment the model is saturated with oil to prepare the model for next flood.

The oil recovery experiments involve, surfactant slug, 0.20 PV in size, polymer slug at a fixed brine concentration, 0.80 PV in size and brine flooding, without polymer up to 4 PV of total injected fluids. Three different salinity concentrations, below, above and at the optimal salinity were used. Some salinity gradient experiments adding a second polymer slug at a lower brine concentration (0.9%) than the primary mobility buffer (1.4%) were also conducted. This second polymer slug was 1 PV in size. No preflushes were conducted in these experiments.

RESULTS

Phase Behavior and Interfacial Tension. A quick screen test using Oil 1 and Witco EOR 2094 Surfactant to determine salinity effect on 3-phase formation indicated that a middle phase would form around the 1% NaCl concentration region. Very low IFT values were measured between this oil and surfactant in 1% NaCl, as shown in table 2.

In the case of Oil 2 and Witco EOR 2095 a phase tubes experiment showed 3-phase behavior for salinities between 1.1 and 1.45% NaCl. Figure 7 shows the phase volumes, and Figure 8 shows the solubilization parameters for this system. Optimum salinity was approximately 1.39% NaCl. The presence of polymer in the solution did not change the optimum salinity. The optimum salinity changed slightly as the ratio of oil components changed. An oil mixture of 87.5% Soltrol 220 and 12.5% motor oil had an optimum salinity of 1.22%. Optimum salinity also decreased as the concentration of surfactant decreased. A 1% surfactant solution with Oil 2 showed a 3-phase region from 0.75% NaCl through 1.2% NaCl. A 0.5% surfactant solution produced a small third phase around 1% salinity. IFT values between Oil 2 and 3% EOR 2095 at optimum salinity were not as low as the IFTs between Oil 1 and 3% EOR 2094.

It was found that Alcoflood 1275 polymer develops the highest viscosity in low salinity brine. Adequate viscosity is generated, however, by a 1,000 ppm polymer solution when prepared in a sodium chloride solution at optimal salinity for the surfactant/oil mixtures under study.

Oil Recovery. Results for the linear cores and the quarter five-spot apparatus are presented here.

Core Experiments. Oil recovery in a linear flow configuration was conducted using the following fluids:

- Brine 1.4% NaCl
- Oil 66.5% Soltrol 220, 33.5% non detergent motor oil SAE 30
- Surfactant 3% Witco EOR 2095, 3% 2-methyl, 1-propanol in 1.39% NaCl, and 1,000 ppm 1275 polyacrylamide.
- Polymer 1,000 ppm Alcoflood 1275 polyacrylamide in 1.4% NaCl
- Chase brine 1.4% NaCl

The planned chemical injection volumes were 0.2 PV or less of surfactant and 1.0 PV or less of polymer. Actual injected PVs were 0.20 for surfactant and 0.77 for polymer. The fluids were injected at a rate of 10 ft/day. Note that this is not a salinity gradient experiment. The system, however, produced over 90% of the oil remaining after waterflood as shown in Figure 9. Some emulsions were produced toward the end of the oil production. They were broken by addition of a small amount of 2-propanol (IPA). These results indicate that the chemical system appears to have adequate oil recovery capabilities.

Quarter 5-Spot Experiments. Figure 10 shows the steady state relative permeabilities measured in the quarter 5-spot for imbibition experiments. The residual water saturation at the beginning of the imbibition flood is approximately 8 %. The residual oil saturation at the end of the imbibition run is approximately 17 %. The water relative permeability showed little hysteresis between primary drainage and imbibition. The oil relative permeability at residual water saturation is 0.49, typical of bead beds, significantly lower than 1 (which is typical of water-wet sandstones). The water relative permeability at residual oil saturation is about 0.51.

The immiscible drainage and imbibition displacements conducted on the quarter five-spot model are listed in Table 4. The model was initially 100 % saturated with water. Before the primary drainage, water is displaced by a mixture of water-glycerol. This is a stable displacement because the water-glycerol mixture is more viscous than pure water. Photographs taken during the experiment showed an almost circular displacement front. This circular front indicates that the medium is not very heterogeneous. This model is not homogeneous, but it is not very heterogeneous either, as indicated by the fronts of the stable displacements. As the floods become unstable, heterogeneities become important. Current theory does not describe immiscible viscous fingering in such mildly heterogeneous media adequately. The main problem is to select adequate values for relative permeability. For imbibition floods, it is expected that the pore-scale flow to be stable and independent of capillary number for $N_{cap} < 10^{-5}$. The steady state relative permeabilities should then be applicable to the imbibition floods¹⁵.

Three kind of experiments have been completed, water floods, chemical floods at optimal salinity, and chemical floods at upper salinity. In the case of water floods the following behavior was observed. Macroscopic (1 cm) and microscopic fingers (1 mm) were present during the imbibition and drainage experiments. The viscosity ratio (10.9) in the imbibition run is adverse while the fluids densities are about the same. Six fingers were observed in this flow. Fingers are rounded, compact and follow the bulk flow direction.

Drainage experiments using this model showed long and slim fingers. More microscopic fingers were also observed in the unstable drainage experiments than in the imbibition ones. The bottom of the model is flooded along with the top in the imbibition experiment while it was not flooded at all for more than 1 PV for the drainage experiments. The injectant and the displaced fluids have about the same density, therefore, no significant gravity override was observed.

During the optimal salinity experiments no fingering was observed until after 1 PV injection anywhere in the model. Microscopic fingering started at that time in the middle area of the model. The fingering moved close to the production port later. The onset of macroscopic fingering was observed at about 2 PV. The fingering was also restricted to the upper right corner of the model. This area is close to the production port. No significant fingering was observed elsewhere in the model. Reverse mobility gradient between the chase water and the mobility buffer seems to be the cause of this behavior.

The upper salinity experiments showed microscopic fingering appearing after injection of 0.8 PV. Macroscopic fingering was observed after 1.5 PV injection. The fingers were somewhat thinner than in the optimal salinity case and they also appeared in the right upper corner of the model. They appeared to channel the driving fluid toward the injection port through the displaced fluid. They occupied a somewhat bigger area of the model than in the optimal salinity case. Interpretation of these results is done jointly with the simulation results in the discussion section.

Figure 11 shows the recovery curves for all the experimental floods. The recovery for the chemical floods was significantly higher than the recovery for the water flood case.

SIMULATION PROGRAM

INTRODUCTION

For a big number of reservoirs, chemical EOR methods may be the only viable methods for significantly reducing oil saturation in the field. The predominant mechanism to recover the remaining oil is lowering the IFT through the addition of suitable chemicals (surfactants). Lower interfacial forces recover additional oil by reducing these capillary forces. This trapping of the resident oil can be expressed as a competition between viscous forces, which mobilize the oil, and capillary forces, that trap the oil.

In practice surfactant injection alone does not achieve sufficient recovery due to several problems, fingering, adsorption, surfactant-soil interactions, etc. Therefore, a more complex process involving different steps is required to fully realize this technique potential. This recovery process receives different names, but throughout this work we have used the term micellar-polymer flooding (MP) following Lake¹.

It has been established that fingering will appear in a flooding process when the mobility of the displacing fluid is higher than the mobility of the displaced fluid¹⁶. This condition results in the viscosity of the displacing fluid being smaller than the one of the displaced fluid. The viscosity ratio is called “adverse” and fingering resulting in lower oil recovery is expected. The lower the water/oil mobility ratio (λ_w/λ_o) the closer the water velocity approaches that of the oil and, consequently, the displacement is more efficient¹⁶. Decreased mobility ratio is obtained with polymer solutions by increased viscosity or decreased permeability of the aqueous phase, or both.

$$M = \frac{\lambda_w}{\lambda_o} = \frac{(k_w / \mu_w)}{(k_o / \mu_o)} \quad (24).$$

Experimental immiscible displacements at adverse viscosity ratios were conducted in a quarter five-spot model in both the drainage and the imbibition modes at comparable viscosity ratios and density differences during this project. The non-wetting fluid is the injectant in the drainage model, whereas the wetting fluid is the injectant in the imbibition mode. The injectant in the imbibition experiments was colored water and the displaced fluid a “pseudo-oil.” Results have been shown in previous reports.

Many commercial simulators have problems reproducing unstable fronts in homogenous porous media¹⁷. Especial numerical techniques are used to reproduce the shape of the displacing fluid front¹⁸. It is also recognized in literature¹⁹ that unstable displacements can be produced by the presence of physical heterogeneities, normally relative permeability variations²⁰.

The goal of the simulation program was to reproduce the experimental results. We did not have problems reproducing the linear floods. Good agreement was found between our calculated and the experimental results (see below). This was not the case when we compared computed and experimental results for the quarter 5-spot. We found that there

was significant variation between the results computed using the UTCHEM²¹ commercial simulator and our experimental results for a "homogeneous" porous medium. We concluded that the porous medium used in our experiments presented enough heterogeneous behavior to affect the results. Therefore, we tried to create a "heterogeneous" porous medium with similar behavior to the experimental one to use in our numerical calculations.

We define a "homogeneous" porous medium as the one having constant permeability throughout the domain. Heterogeneity was added to a homogeneous porous medium similar to the one used in the experiments. A mildly heterogeneous porous medium was created by adding diagonal permeability bands to the base homogeneous porous medium. We selected a computational porous medium that matched our experimental results for the adverse water floods. The results for the different chemical floods were computed and compared to the experimental results.

SIMULATOR BACKGROUND

UTCHEM, a chemical simulator developed by researchers at the University of Texas at Austin²¹, has been used for the simulation program. UTCHEM is a multi-component, multiphase, three-dimensional compositional with variable temperature simulation model²¹. The basic equations are as follows:

- 1) the mass balance equations, which are solved up to 21 species;
- 2) the aqueous phase pressure, which is obtained by an overall mass balance on volume occupying species (water, oil, surfactant, alcohol, and gas). The other phase pressures are computed by using the capillary pressures between phases;
- 3) the energy balance equation, which includes heat flow between the reservoir and the overburden rocks.

The flow equations allow for compressibility of rock and fluids, dispersion and molecular diffusion, chemical reactions, and phase behavior and are complemented by constitutive equations. The model includes options for multiple wells completed either horizontally or vertically. Aquifer boundaries are modeled as constant potential surfaces or as closed surfaces.

The flow equations are solved using a block-centered finite-difference scheme. The solution method is implicit in pressure and explicit in concentration (IMPES-like). Either one, two-point upstream, or third-order spatial, discretization is used. A brief description of the equations used in the code is provided below.

Mass Conservation Equations. The assumptions imposed when developing the flow equations are:

- 1) local thermodynamic equilibrium, except for tracers;
- 2) immobile solid phases;
- 3) slightly compressible rock and fluids;

- 4) Fickian dispersion;
- 5) ideal mixing; and
- 6) Darcy's law.

The boundary conditions are no flow and no dispersive flux across the impermeable boundaries. The mass continuity for component k in association with Darcy's law is given in terms of overall volume of component k per unit pore volume ($\tilde{C}_k$) as,

$$\frac{\partial}{\partial t}(\phi \tilde{C}_k \rho_k) + \nabla \cdot \sum_{j=1}^{n_p} \mathbf{r}_k (C_{kj} \mathbf{u}_j - \nabla \cdot \underline{\underline{D}}) = R_k \quad (25),$$

where the overall volume of component k is the summation over all phases including the adsorbed phases,

$$\tilde{C}_k = \left\{ 1 - \sum_{k=1}^{n_{cv}} \hat{C}_k \right\} \sum_{j=1}^{n_p} S_j C_{kj} + \hat{C}_k, \quad \text{for } k=1, \dots, n_{cv} \quad (26),$$

n_{cv} is the total number of volume occupying components. These components are water, oil, surfactant, and gas, n_p is the number of phases, $\hat{C}_k$ is the adsorbed concentration of species k, and ρ_k is the density of pure component k at a reference phase pressure P_r relative to its density at reference pressure P_{ro} , usually taken at a surface condition of 1 atm.

The phase flux from Darcy's law is given by,

$$\mathbf{u}_j = - \frac{\mathbf{k}_{rj} \mathbf{k}}{\mu_j} \cdot (\nabla P_j - \gamma_j \nabla h) \quad (27),$$

where $\mathbf{k}$ is the intrinsic permeability tensor and h is the vertical coordinate, $\mathbf{k}_{rj}$, μ_j , and γ_j are the relative permeability, viscosity, and specific weight for phase j. The source terms R_k are a combination of all rate terms for a particular component.

Pressure Conservation Equations. The pressure equation is developed by summing the mass balance equations over all volume occupying components, substituting Darcy's law for the phase flux terms, using the definition of capillary pressure, and noting that

$(\sum_{k=1}^{n_{cv}} C_{kj}) = 1$. The pressure equation in terms of the reference phase pressure (phase 1) is given by,

$$\begin{aligned} \phi C_t \frac{\partial P_j}{\partial t} + \nabla \cdot \mathbf{k} \cdot \lambda_{rTc} \nabla P_j = & - \nabla \cdot \sum_{j=1}^{n_{cv}} \mathbf{k} \cdot \lambda_{rTc} \nabla h + \\ & + \nabla \cdot \sum_{j=1}^{n_{cv}} \mathbf{k} \lambda_{rTc} \cdot \nabla P_{c_{jw}} + \sum_{j=1}^{n_{cv}} Q_k \end{aligned} \quad (28),$$

where the total relative mobility including the correction for fluid compressibility is given by $\lambda_{rTc} = \sum_{k=1}^{n_{cv}} \lambda_{rjc}$, and $\lambda_{rjc} = \frac{k_{rj}}{\mu_j} \sum_{k=1}^{n_{cv}} r_k C_{kj}$. C_t is the total compressibility calculated as the volume weighted sum of matrix and component compressibilities.

Fluid and Soil Properties. Geological heterogeneities are the key factor that reduces the effectiveness of chemical enhanced recovery processes because their success depends on the delivery of injected chemicals and water into the subsurface. In order to capture some of the geological features, reservoir properties such as formation permeability, porosity, residual phase saturation, phase relative permeability, and phase capillary pressure are allowed to vary spatially in UTCHEM. Phase trapping functions and adsorption of both surfactant and polymer are modeled as a function of permeability.

Polymer Adsorption. Polymer adsorption can be an important mechanism for a chemical recovery project since it causes retardation polymer consumption. The retention of polymer molecules in permeable media is due to both adsorption onto solid surfaces and trapping within small pores. UTCHEM uses a Langmuir-type isotherm to describe the adsorption level of a polymer, which takes into account the salinity, polymer concentration, and soil permeability²¹. The adsorption is irreversible with concentration and reversible with salinity. The adsorbed concentration ($\hat{C}_p$) is given by,

$$\hat{C}_p = \min \left\{ \tilde{C}_p, \frac{a_p (\tilde{C}_p - \hat{C}_p)}{1 + b_p (\tilde{C}_p - \hat{C}_p)} \right\} \quad (29).$$

The minimum is taken to guarantee that the adsorption is no greater than the total polymer concentration. Adsorption increases linearly with effective salinity and decreases as follows,

$$a_p = (a_{p1} + a_{p2} C_{SEP}) k^{-0.5} \quad (30).$$

The adsorption parameters a_{p1} , a_{p2} and b_p are found by matching laboratory polymer adsorption data. The effective salinity for polymer (C_{SEP}) is,

$$C_{SEP} = \frac{C_{s1} + (\beta_p - 1) C_{61}}{C_{w1}} \quad (31),$$

where C_{s1} , C_{61} , and C_{w1} are the anion, calcium, and water concentrations in the aqueous phase and β_p is experimentally determined.

Viscosity. Liquid phase viscosities are modeled in terms of pure component viscosities and the phase concentrations of the organic, water and chemicals,

$$\mu_k = C_{wk} \mu_k e^{\alpha_w (C_{ok} + C_{chk})} + C_{ok} \mu_k e^{\alpha_o (C_{wk} + C_{chk})} + C_{chk} \mu_k e^{\alpha_{ch} (C_{wk} + C_{ok})} \quad (32),$$

for k = water, oil or chemical.

The α parameters are determined by matching laboratory microemulsion viscosities at several compositions. In the absence of polymer, water and oil phase viscosities are

reduced to pure water and oil viscosities. When polymer is present μ_w is replaced by μ_p defined below.

The viscosity of the polymer solution depends on the concentration of polymer and on salinity,

$$\mu_p^o = \mu_w \{ 1 + (A_{pw} C_{pw} + A_{po} C_{pw}^2 + A_{pch} C_{pw}^3) C_{SEP}^{Sp} \} \quad (33),$$

where C_{pw} is the polymer concentration in water, μ_w is the water viscosity, A_{pi} are constants. The factor C_{SEP}^{Sp} allows for dependence of polymer viscosity on salinity and hardness.

The reduction in the viscosity of the polymer solution is a function of shear rate (γ) and is modeled by using Meter's equation²²,

$$\mu_p = \mu_w + (\mu_p^o - \mu_w) / (1 + \{ \gamma / \gamma_{1/2} \}^{P\alpha-1}) \quad (34),$$

where $\gamma_{1/2}$ is the shear rate at which viscosity is the average of μ_p^o and μ_w , and $P\alpha$ is an empirical coefficient.

Surfactant/Brine/Oil phase behavior. The surfactant-oil-water phase can be represented as a function of effective salinity once the binodal curve and the tie-lines are described. The phase behavior model in the UTCHEM simulator uses Hand's rule²³, and is base on the work by Nelson and Pope⁶, Satoh²⁴ and Camilleri et al.²⁵. The effective salinity increases with the divalent cations bounded to micelles (Camilleri et. al.²⁵, Hirasaki²⁶) and decreases as the temperature increases for anionic surfactants. Effective salinity concentration (C_{Se}) is calculated using,

$$C_{Se} = \frac{C_{s1}}{(1 - \beta_6 f_6^s) [1 + \beta_T (T - T_{ref})]} \quad (35),$$

where C_{s1} is the aqueous phase anion concentration; β_6 is a positive constant; f_6^s is the fraction of the total divalent cations bounded to the surfactant micelles; and β_T is the temperature coefficient.

The formulation of the binodal curve using Hand's rule²³ is assumed to be the same in all phase environments. Hand's rule is based on the empirical observation that equilibrium phase concentration ratios are straight lines on a log-log plot scale. Figures 3a and 3b show a type II(-) ternary diagram and its corresponding Hand plot. The binodal curve is computed from,

$$\frac{C_{3j}}{C_{2j}} = A \left\{ \frac{C_{3j}}{C_{1j}} \right\}^B, \text{ with } j = 1, 2, \text{ or } 3 \quad (36),$$

where A and B are empirical parameters. For a symmetric binodal curve where $B = -1$ all phase concentrations are calculated explicitly in terms of oil concentration C_{2j} .

$$C_{3j} = 0.5 \left[-A C_{2j} + \sqrt{(A C_{2j})^2 + 4A(1 - C_{2j})} \right], \text{ for } j = 1, 2, \text{ or } 3 \quad (37).$$

Parameter A is related to the height of the binodal curve as,

$$A_m = \left\{ \frac{2 C_{3\max,m}}{1 - C_{3\max,m}} \right\}, \text{ for } m = 0, 1, \text{ and } 2 \quad (38),$$

where 0, 1, and 2 are numbers related to the maximum heights of the binodal curve measured for low, optimal and high salinities. The height of the binodal curve is specified as a linear function of temperature:

$$C_{3\max,m} = H_{\text{BNC},m} + H_{\text{BNT},m} (T - T_{\text{ref}}) \quad (39),$$

where $H_{\text{BNC},m}$ and $H_{\text{BNT},m}$ are input parameters. A_m is linearly interpolated as,

$$A = (A_0 - A_1) \left[1 - \frac{C_{\text{Se}}}{C_{\text{Seop}}} \right] + A_1, \text{ for } C_{\text{Se}} \leq C_{\text{Seop}} \quad (40),$$

$$A = (A_2 - A_1) \left[\frac{C_{\text{Se}}}{C_{\text{Seop}}} - 1 \right] + A_1, \text{ for } C_{\text{Se}} \geq C_{\text{Seop}} \quad (41),$$

where C_{Seop} is the optimum effective salinity calculated as the arithmetic average of C_{Sel} and C_{Seu} . The heights of the binodal curve at three reference salinities are estimated based on phase behavior laboratory experiments.

CORE FLOOD RESULTS

The UTCHEM simulator has several interesting features that can be used to thoroughly study the chemical flooding process. Saturation, concentration, viscosity, IFT and other property profiles can be obtained as results of appropriate simulation runs. The integration domain is divided in blocks. We used eleven blocks in the x direction in our coreflood studies. The simulator also calculates the system phase behavior block by block, reporting a phase behavior profile that can be compared with the phase behavior information obtained using other properties.

Typical results for our simulations are shown in Figure 12. Effective salinity is plotted versus the core axial dimension (x). The effective salinity concentration profile decreases monotonically from the core entrance to the core exit. The first four blocks have an effective salinity concentration higher than the upper limit, therefore, a II(+) behavior is expected for these blocks. A micro-emulsion phase will be at equilibrium with an aqueous phase. Blocks 5 to 8 are within the upper and lower effective salinity limits, therefore, three phases will be at equilibrium in those blocks. Block 5 has been reported to behave as a type 4 phase behavior. According to the UTCHEM simulator convention, type 4 represents the equilibrium in the left lobe (II(+)) of a type III region. Blocks 9 to

11 are located below the lower salinity limit, therefore, a II(-) behavior is expected for these blocks. A micro-emulsion phase will be at equilibrium with an oil rich phase. Figures 13 through 15 show the variation of different properties along the core plug. The variation of these properties can be interpreted using the phase behavior discussed above. The relationship between these properties and the oil recovery efficiency can also be determined from the study of these figures. A zero value for any property in any of the three phases means that this phase is not present in the block under consideration.

Figure 13 shows the variation of viscosity with position. Oil viscosity is zero for the first four blocks and aqueous phase viscosity is zero for the last three. This result is in agreement with the phase behavior discussed above. The viscosity plays a big role in the efficiency of the recovery process. The aqueous phase is more than ten times less viscous than the oil phase (1 cp to 10.9 cp). Therefore, polymer is added to the mobility buffer to avoid fingering. This figure reflects the situation after injection of 0.5 PV. The viscosity of the aqueous and micro-emulsion phases is higher than the oil phase viscosity for blocks 1 to 7. Blocks 8-11 present higher oil phase viscosity. Other simulation results, not presented here, showed that the oil bank moves towards the production part of the core as the injected volume increases. In conclusion, the oil bank is pushed towards the production well by the more viscous aqueous and micro-emulsion phases. This situation can be observed in Figure 14. The oil saturation is zero or nearly zero for the first five blocks and increases very rapidly for the blocks 6 to 11. The micro-emulsion phase saturation profile presents a maximum at block 6 decreasing for blocks 7 to 11. Aqueous phase saturation decreases from blocks 1 to 7. Water is being trapped into the micro-emulsion phase. Then, it disappears in blocks 8 to 11.

Figure 15 shows values of interfacial tension (IFT) within the core plug. Decimal logarithm of IFT is plotted vs. X direction. There are two possible interfaces for this system micro-emulsion/water and micro-emulsion/oil. The IFT value is different for both interfaces when three phases are present, blocks 6 to 8. Equal IFT values imply that only two phases are present, blocks 1 to 5 and 9 to 11. The Figure also shows that from block 1 to 10 the IFT is significantly smaller than the pure water IFT value (+1.65 mN/m). These low values are produced because the effective salinity is everywhere within close proximity of the optimal salinity range. This figure is an extreme example of the reduction in IFT reached through adjustment of the effective salinity. The high recovery achieved in this case, even for a high viscous oil, shows the potential of chemical flooding methods to recover residual oil.

Figure 16 shows a comparison between experimental data and simulation results for oil production. There is good agreement for all values between simulation results and experimental data. The biggest discrepancy occurs for small values of PV. The calculated results predict higher recovery than the experimental data. For medium and high volumes the results are practically the same. This Figure shows that the simulation results can be used with reasonable confidence to design these processes.

COMPUTATIONAL QUARTER 5-SPOT

The UTCHEM²¹ commercial simulator was used to compute our results. We started from a base waterflood. The data corresponding to the porous medium are shown in Table III. Properties of the fluids used in the experiments are shown in Table IV. The recovery curve is shown in Fig. 17 for the experimental data and numerical results. It can be seen that there is a significant difference between the numerical and experimental data for this case after a PV value of 0.4. After an injection value of 0.4 the flow pattern becomes fixed and there are no more changes in the recovery value. This fact is discussed in a more detailed way below.

We observed six fingers relatively rounded in the experimental runs. The fingers became significant after an injection of 0.6 pore volumes (PV). It is clear that the numerical results do not match the experimental ones. We added heterogeneities to the “computational porous media” in order to improve the agreement between experiments and simulation results. The goal was to achieve similar qualitative flow behavior (number of fingers, shape, etc.) and quantitative agreement on the recovery values.

An increasingly heterogeneous porous medium was developed by adding diagonal bands with different permeability values than the base homogeneous porous medium. One, three and five diagonal bands were added (see Figure 18). The width of the bands was one block in all cases. Several values of permeability were used. The base value for the homogeneous porous media was 1.25 darcy. A diagonal permeability range between 1.26 and 10 darcies was used in our simulations. We started with relatively high values, but our calculations showed that only small variations from the base permeability value produced changes in the quantitative and qualitative results.

Results. Figure 19 shows the recovery value given as percentage of Oil in Place (%OOIP) as a function of the permeability value in the heterogeneous bands for the cases of 3 and 5 bands. Qualitative observations showed that the one diagonal case did not match the number of fingers, therefore, it was dropped from the selection. Figure 20 shows the three bands case for a permeability value of 1.3 darcys. There are three fingers in this case and the recovery value is close enough (43%) to the experimental value (44%). This case is competitive with the five bands with a permeability of 1.28 darcys case. We found that different 3 and 5 bands cases have similar recovery results, but the qualitative picture was different. The case depicted by Figure 20 is a clear example, while 5 bands produced five fingers and a relative symmetric flow pattern, the 3 bands case did not. In the three bands case there was a non-symmetrical channel on the upper part of the porous medium. The number of fingers finally decided us to select the 5 bands case with a permeability value of 1.28 darcys on a background value of 1.25 darcys.

We completed the study by looking at the time progression of the displacing front. We observed that a lower times you have small fingers that lead to the macroscopic fingers later on. The simulation results showed a channeling pattern, given by regions of the domain with higher water saturation even for the case when we have not achieve water breakthrough yet (Figure 21). After breakthrough is reached a channeling pattern is

established and there is not further change neither in the qualitative flow picture and the recovery value. Similar observation was made in experiments performed using higher injection rates than the base one reported here ($0.047 \text{ m}^3/\text{day}$).

Figure 22 shows that very small variations in the permeability value can produce big variation in the recovery value. These results should be interpreted with care because part of the heterogeneity can be produced by numerical errors associated with the simulator.

CHEMICAL FLOOD QUARTER 5-SPOT RESULTS

Typical results for our simulations are shown in Figure 23. This figure corresponds to an optimal salinity chemical flood after 1.1 PV injection. The contour plot shows number of phases present, for example, a three value represents; aqueous, oil and micro-emulsion phases present. We can observe that there are three phases present almost everywhere inside the physical model. This phase behavior occurs because the effective salinity is within optimal value range in the whole model. Figure 24 shows this to be the case. Only at the injection port and small regions on the top and upper right sides of the model are below optimal salinity concentration. Therefore, we can expect these two areas to present two phase behavior instead of three.

Figures 25 to 29 show contour plots of significant properties inside the physical model. Figure 25 shows a water phase viscosity contour plot. An annular front describes the position of the mobility buffer. The leading edge of this front extends from $Y=0.8$ to $X=0.8$. The rear part of this front extends from $Y=0.6$ to $X=0.6$. No fingering was observed on the leading edge of the front, but microscopic fingering was present in the rear edge. As the injection volume increases the fingering increased in size and moved towards the production port as the experiment continued. Figure 25 also shows that the location of the mobility buffer corresponds with a region of high viscosity driving a lower viscosity bank in front. The viscosity decreases for the chase water bank moving after the mobility buffer. The presence of this lower viscosity bank can cause a reverse mobility displacement and produce fingering. This situation is depicted in Figure 26. We can see that the adverse viscosity ratio produces micro fingering in the tail of the displacing front between the water phase, with low viscosity, and the microemulsion phase, with higher viscosity. There is no fingering in the front of the leading edge.

The viscosity of the microemulsion phase increases as the injection volume increases. This behavior is produced by increased concentration of polymer in the microemulsion phase. At some value of injection volume the viscosity of the microemulsion phase becomes higher than the viscosity of the displacing water producing unstable flow and fingers. This adverse viscosity ratio is responsible for the fingers appearing on the region close to the production port. Most of the oil present in the neighborhood of the production port is dissolved in the microemulsion phase. Therefore, for conditions of poor sweeping efficiency this oil can not be recovered. This situation is shown in Figure 27.

Figure 28 shows that in about 40% of the physical model the oil phase saturation is below the residual oil saturation for the water flood (0.17). The average oil saturation for the whole model at that point is 0.177, very close to the residual oil saturation value. This fact shows that the surfactant presence increases the oil solubility below residual oil saturation, and, therefore, increases oil recovery.

Figure 29 shows that the presence of three phases is related to very low interfacial tension values. The presence of three phases creates two interfaces, micro-emulsion/water and micro-emulsion/oil. Typical values for the micro-emulsion/water interface are shown in Figure 29. Interfacial tension values range from 10^{-4} to 10^{-2} mN/m, -4 to -2 for $\log_{10}$ values; within the physical model. Only areas close to the injection and production ports present higher interfacial tensions. Slightly lower values were computed for the micro-emulsion/oil interface.

Figure 30 shows the computed recovery results for all the floods. Three different chemicals floods were simulated, upper and optimal salinity and a salinity gradient flood. The salinity gradient experiment produced the highest recovery. The optimal and upper salinity floods followed closely. All chemicals floods increased significantly the recovery compared to the water flood. There was not preflush in all the simulations. The main difference between the salinity gradient and the other chemical floods is the sudden reduction of salinity concentration in the chase water. These results agree well with the experimental data reported by Chou and Shah³.

The main mechanisms increasing oil recovery in surfactant-polymer flooding are, increased solubility produced by low interfacial tension and improved mobility control. In order to understand how both mechanisms affect recovery in our floods we plotted average phase saturations vs. PV injected for the optimal salinity and the salinity gradient floods. Figures 31 and 32 show our results. Fig. 31 shows that the oil phase saturation decreases during the flood, reaching a practically constant value (0.17) after 1.5 PV. The aqueous phase saturation increases continuously during the calculation. The micro-emulsion phase average saturation presents a maximum at 0.5 and then decreases in value. The final average saturation value for the micro-emulsion phase is 0.11. The total recovery for this flood is 76%. A volume balance for the oil phase accounts only for 93% of the oil volume originally in place, 76% produced and 17% retained as residual oil saturation. The other 7% was found to be dissolved in the micro-emulsion phase. If the final average saturation value for this phase is 11% we can conclude that the micro-emulsion phase is an "oil-rich" phase. This conclusion shows that the very low interfacial tension does indeed solubilized the oil. Unfortunately, a contour plot of micro-emulsion phase viscosity after 2 PV shows that the micro-emulsion phase has very high viscosity in the region close to the production port. Most of the micro-emulsion phase is located in this region after 2 PV injected. This viscosity is higher than the chase water viscosity and produces channeling and fingering in the region close to the production port. An analysis of the composition of the micro-emulsion phase shows that the high viscosity is produced by polymer solubility in this phase. The practical implication of these findings is that despite the fact that you solubilize a big amount of oil you can not produce part of it. The micro-emulsion phase is trapped in the regions close to the production port and can not be mobilized due to the reverse mobility gradient. In this simulation 7% of the total oil in place is trapped under these conditions.

Figure 32 shows a similar plot for the salinity gradient case. The oil phase behaves similarly to the previous case, reaching a practically constant value (0.19) after 1.5 PV. The behavior of the system is the same up to 1.1 PV injected. This, of course, is expected, but a completely different behavior occurs after this PV value. The salinity shock decreases the salinity concentration from 1.4% to 0.9%. The change in salinity changes drastically the phase behavior with an increasing area of the physical model where only two phases are present. The phase behavior is $\text{II}(-)$, i.e., you have a micro-emulsion phase and an oil phase. The salinity shock produces a second maximum in the micro-emulsion phase average concentration. This increase is produced at the expense of the aqueous phase that decreases up to a very low value (0.06). There is a recovery of the relative average saturation values of the aqueous and micro-emulsion phase as the simulation proceeds, though. The micro-emulsion phase continuously decreases after 1.5 PV and the aqueous phase continuously decreases. The final average saturation value for the micro-emulsion phase is 0.255. This final value is significantly higher than the final value in the optimal salinity simulation (0.11). A viscosity contour plot also shows that this micro-emulsion phase presents high viscosity. The reason is also polymer solubility in this phase. Therefore, the micro-emulsion phase is also trapped in the region close to production port as was the case in the previous experiment. An analysis of the concentration of this micro-emulsion phase shows that only 3% oil is retained in this case. The main difference between both cases seems to be that the optimal salinity slug solubilizes more oil than the lower salinity slug produced during the salinity gradient flood. The total oil production in this case, 78.8%, was the highest of all the floods. The conclusion in this case is that despite the fact that less oil is solubilized more of it can be produced. The reason is that the polymer solubility increases at lower salinity concentration³ and, therefore, better mobility control exists.

This interplay between phase behavior and mobility control should be optimized to improve oil recovery by chemical methods.

CONCLUSIONS

Linear stability analysis techniques have been used to determine the onset of fingering in a porous medium. The equations corresponding to the problem under study were derived. The solution curve for the one dimension case presents a turning point at a mobility ratio of 1. Stability analysis shows that there is a stable displacement before the turning point and an unstable displacement after. Our results proved the soundness of the stability analysis approach.

Fluid systems were evaluated for oil recovery studies in this project. The selected chemicals and fluids allow adjustments in fluid properties to study surfactant-polymer interactions under variable but controlled conditions. These properties were successfully tested in linear and quarter 5-spot flooding experiments.

Simulation results agreed satisfactorily with experimental data for core floods. Discrepancies were found in the case of quarter 5-spot floods. The quarter five-spot used in these experiments was found to be "mildly" heterogeneous. A slightly heterogeneous porous medium was computationally created by adding diagonal bands with different permeability values to the base homogeneous porous medium. Several permeability values for the diagonal bands were tried and a selection was made based on qualitative flow behavior (number of fingers, shape, etc.) and quantitative agreement with the experimental recovery values.

Simulation results allowed us a thorough evaluation of the properties affecting recovery efficiency. Phase behavior was determined primarily by the effective salinity value. A flooding experiment conducted within a small range of optimal salinity can achieve very low IFT and increased "solubility" of the oil in a micro-emulsion phase. Mobility control was also important. The presence of a mobility buffer with a viscosity equal or higher than the mobilized oil increased significantly the recovery efficiency. The presence of a micro-emulsion phase close to the production well with high viscosity can decrease the recovery value. Emulsion breakers and/or salinity gradient floods can improve significantly the recovery.

The interaction between increased solubility and mobility control seems to determine the success of the recovery. In conclusion these experiments and calculations showed the potential of micellar-polymer flooding as a tertiary oil recovery process.

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NOMENCLATURE

a_p	Parameter defined eqn. (30)
A_m	Parameter appearing eqn. (38)
C_t	Total compressibility
C_{kj}	Volumetric concentration of species k in phase j
C_{SE}	Salinity concentration defined eqn. (35)
C_{Sel}	Lower salinity concentration
C_{Seu}	Upper salinity concentration
C_{SEP}	Salinity concentration for polymer defined eqn. (31)
C_{Seop}	Optimum effective salinity
$C_{3max,m}$	Concentration at the maximum of the bimodal curve defined eqn. (39)
$\tilde{C}_k$	Overall volume of component k per unit pore volume
$\hat{C}_k$	Adsorbed concentration of species k
$G_{(x,y)}$	Function defined eqn. (11)
h	Vertical height from reference level (m)
$H_{(x,y)}$	Function defined eqn. (12)
$H_{BNC,m}$	Input parameter used eqn. (39)
$H_{BNT,m}$	Input parameter used eqn. (39)
IFT	Interfacial Tension (N/m)
k	Absolute permeability (m^2)
$\underline{k}$	Intrinsic permeability tensor (m^2)
k_i	Relative permeability of phase i
K	Absolute Permeability (Darcy)
L_x	X direction length (m)
M	Mobility ratio defined eqn. (23)
n_{cv}	Total number of volume occupying components
n_p	Number of phases

N_{Bond}	Bond dimensionless number
N_{cap}	Capillary dimensionless number
P_c	Capillary pressure (Pa)
P_i	Pressure of phase i (Pa)
P_r	Relative pressure
PV	Pore volume (m^3)
Q_k	Injection/Production volume fraction (sec^{-1})
R_k	Combination of all rate terms
S_k	Saturation of phase k
x	X direction length (m)
x_f	Generic x direction point (m)
t	Time (sec)
T	Temperature (K)
u_i	Darcy velocity of phase i (m/s)
Z	Height (m)

Greek Letters

α_i	Parameters used eqn. (32)
γ_k	Specific gravity of phase k (N)
$\gamma_{1/2}$	Shear rate used to calculate viscosity
ϵ	Perturbation parameter defined eqn. (11)
ϕ	porosity
λ_k	Relative mobility of species k
μ_k	Viscosity of species k ($\text{kg m}^{-1} \text{s}^{-1}$)
Φ_k	Pressure potential
ρ	Density (kg/m^3)
σ	Superficial Tension (N/m)

Subscripts

o	oil
r	ratio
w	water
k	component
max	maximum

ACADEMIC ACTIVITIES

PUBLICATIONS

A paper entitled "Surfactant-Polymer Interaction in Enhanced Oil Recovery" has been published in the Proceedings of the 7th Annual HBCU Energy Symposium. The same material has been presented in the aforementioned Symposium held in Miami, Florida, March 16-18, 1999.

STUDENT ACTIVITIES

Mr. Norman Alban, a graduate student at the Chemical Engineering Department at Prairie View A&M University, presented his Master Thesis entitled "Analysis of Surfactant-Polymer Interaction in Enhanced Oil Recovery" during May, 1999. Mr. Alban work covers the material presented in this final report. Mr. Ahmed Noman , another Prairie View A&M University graduate student continues working in this research area. Mr. Noman is using the quarter 5-spot apparatus, built by Mr. Alban to study selected gel placement in porous media.

TABLES AND FIGURES

TABLE 1. Petroleum Sulfonates from Witco Corporation		
	EOR 2094	EOR 2095
	Petroleum Sulfonate	Petroleum Sulfonate
Equivalent Wt.	422	416
% Active	50.6	50

Table 2. IFT as a function of time for Oil 1 and EOR 2094	
3% 2094, 3% IBA, 1.0% NaCl	
SAE 30/32% Decane	IFT (mN/m)
Time (min.)	0.00565
0	0.00458
2	0.00559
5	0.00560
10	0.00582
15	0.00323
25	0.00341
	0.00326

Table 3. Quarter 5-Spot Characteristics	
Thickness (m)	0.0254
Width (m)	0.419
Area (cm ²)	1755.6
Pore Volume (ml)	1627.6
Porosity	0.365
Permeability (darcys)	15

Table 4. Immiscibles Displacements.		
Displacement	Drainage	Imbibition
Displacing fluid	Oil	Water
ρ (g/cc)	0.89	1.01
μ (cp)	10.9	1
Displaced fluid	Water 2	Oil
ρ (g/cc)	1.21	0.89
μ (cp)	10.1	10.9
$\Delta\rho$ (gm/cc)	0.21	-0.42
Viscosity ratio	10.1	1.08
Initial S_w	1	0.08

Fig. 1. Cross section of a typical micellar-polymer flood.

Fig. 2. Ternary diagram representation of micellar-polymer phase behavior.

Fig. 3. Correspondence between a ternary diagram and a Hand plot.

Fig. 4. Physical model for stability analysis.

Fig. 5. Perturbation solution as a function of the mobility ratio.

Fig. 6. Core flood apparatus

Fig. 7. 2-phase and 3-phase regions as a function of increasing salt concentration for the Witco EOR 2095 surfactant and Oil 2.

Fig. 8. Oil and water solubilization parameters as a function of salinity. Optimum salinity for the system is at a concentration of approximately 1.39% NaCl.

Fig. 9. Oil cut and recovery efficiency as a function of fluid injected for an oil recovery experiment in a Berea sandstone core plug.

Fig. 10. Steady-state relative permeabilities for imbibition experiments.

Fig. 11. Experimental recovery curves.

Fig. 12. Relationship between phase behavior and effective salinity along the Berea core plug.

Fig. 13. Viscosity change along the Berea core plug.

Fig. 14. Phase saturations inside the Berea core plug.

Fig. 15. Interfacial tension (IFT) along the Berea core plug.

Fig. 16. Comparison of experimental data and simulation results for linear displacements.

Fig. 17. Comparison of experimental data and simulation results for water floods in a quarter 5 spot.

a). One diagonal permeability band.

b). Three diagonal permeability bands.

c). Five diagonal permeability bands.

Fig. 18. Different porous media prepared to use in numerical calculations.

Fig. 19. Recovery value as a function of the diagonal permeability value.

Fig. 20. Water saturation pattern for five diagonal bands after 0.4 PV.

Fig. 21. Water saturation pattern for five diagonal bands after 0.20 PV.

Fig. 22. Recovery change as a function of the permeability value in the five diagonal bands.

Fig. 23. Phase behavior after 1.1 PVs injected.

Fig. 24. Effective salinity (meq./ml) contour after 1.1 PVs injected. Optimal salinity between 0.0198 and 0.023 meq./ml.

Fig. 25. Water phase viscosity after 1.1 PVs. Injected.

Fig. 26. Water saturation profile after 1.1 PV injected.

Fig. 27. Micro-emulsion saturation profile after 1.1 PV injected.

Fig. 28. Oil saturation contour after 1.1 PV injected.

Fig. 29. Log_{10} IFT contour for the water-micro-emulsion interface (1.1 PV injected).

Fig. 30. Influence of salinity on surfactant-polymer recovery.

Fig. 31. Average phase saturations time change for optimal salinity.

Fig. 32. Average phase saturations time change for salinity gradient.