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Quarterly Technical Progress Report

IMPROVED EFFICIENCY OF MISCIBLE CO_2 FLOODS AND ENHANCED PROSPECTS FOR CO_2 FLOODING HETEROGENEOUS RESERVOIRS

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OBJECTIVE

The objective of this experimental research is to improve the effectiveness of CO_2 flooding in heterogeneous reservoirs. Activities are being conducted in three closely related areas: 1) exploring further the applicability of selective mobility reduction (SMR) in the use of foam flooding, 2) exploring the possibility of higher economic viability of floods at slightly reduced CO_2 injection pressures, and 3) taking advantage of gravitational forces during low interfacial tension (IFT), CO_2 flooding in tight, vertically fractured reservoirs.

SUMMARY OF PROGRESS

Progress made this quarter in each of the three areas of the project is discussed below.

TASK 1 - CO_2-FOAMS FOR SELECTIVE MOBILITY REDUCTION (SMR)

Additional progress on this task has been made in the past quarter in both experimental and analytical directions. A new series assembly of two Berea cores has been made and is currently being investigated, and new and definitive results have been obtained from the parallel experiment, where we are studying the effect of capillary contact on foam effectiveness and SMR. This work has also pointed out interesting aspects of surfactant-less two-phase flow in heterogeneous media. In addition, a simulation method, which allows assessment of the economic usefulness of the SMR property by which displacement fluid mobility is reduced to a greater extent in high than in low permeability zones of the reservoir, has been programmed.

The series assembly uses two cores of 1/2" diameter, each in length of approximately 3 in. In these tests, two Berea samples of different permeability are used. The coreholder is fitted with five equally spaced pressure taps, in such a way that the middle tap is quite near the junction between the cores. In a series of tests discussed in the previous quarterly report, the contact material was a fine filter paper. As noted previously, however, for this first series core assembly, there was a pressure anomaly at the junction during two-phase and foam flow. This was apparently due to the increased capillary pressure required to force bubbles of the non-wetting phase (the dense CO_2) through the small pores of the filter medium. Because this anomaly made the data analysis for mobility experiments more difficult and less straightforward, a second assembly was constructed. In this, the unavoidable space between the two core faces was filled with a fine sand, of a grain size such that its packed permeability was about equal to that of the lower permeability Berea core (about 100 md). Initial mobility experiments with this second system are currently being conducted.

In the parallel experiments, two different coaxial porous systems were used.[1] These composites, 2.75" (7.0 cm) long by 1.46" (3.7 cm) diameter, consist of a fired Berea core with a 5/8" (1.59 cm) central hole drilled from end to end. This central region is filled with relatively uniform (either sieved or elutriated) silica sand particles. In the two different series of tests, the central sandpacks had permeabilities of 0.5 darcy and 5.2 darcy, while the annular Berea regions had permeabilities of 1.40 and 1.37 darcy.

Steady-state flow tests were performed with this apparatus to measure overall permeability to brine alone, total mobility during simultaneous flow of CO_2 and brine mixtures, and mobility of CO_2-foam. In these experiments, capillary contact between the two permeability zones produced striking results in our mobility measurements in both surfactant-free flow and in the flow of CO_2-foam. This difference apparently occurs because in these experiments the fluids can flow laterally through the side boundary in response to any capillary pressure difference that might exist between the zones. Such a difference would exist if the brine saturation were the same across the zone boundary. The capillary contact might be expected to cause an equalizing flow of brine from the lower to the higher permeability region.

This equalization occurs strongly during the simultaneous flow of CO_2 and brine with no surfactant, and as a result, the high permeability zone becomes drier (richer in CO_2), while the low permeability zone becomes wetter. This increases the ratio of the mobilities in the two zones to a value significantly greater than the permeability ratio. Thus, the rate of CO_2 flow through the high permeability region is even greater than might be expected.

The existence of the effect suggests that in ordinary WAG-type CO_2 floods, oil recovery can be even less than expected. Because most if not all real reservoirs are heterogeneous — that is, they consist of both high and low permeability rock with the different zones often lying parallel to each other and being in capillary contact — CO_2 flow in conventional CO_2 floods will be even more non-uniform than the permeability distribution suggests. In a reservoir, even more of the oil in the lower permeability zones would be left relatively untouched.

When surfactant was present in the brine, this relative difference in the mobilities between different permeability zones was greatly reduced. The amount of the reduction depended on both flow rate and on whether the high or low permeability zone was in the center.

Over the range of flow rates of the tests, the mobility for two-phase brine/CO_2 in the first set of experiments averaged 9.4 times that of brine alone (that is, arising from the permeability ratio). For foam made with 500 ppm surfactant brine, the corresponding ratios were 1.9 for CD1050*, 1.3 for X2001**, and 1.0 for CD1045*. For 2500 ppm foam, the corresponding numbers were somewhat lower: 1.8, 1.2 and 1.4. A second set of experiments was conducted over the same range of flow velocities, where the center zone consisted of a lower permeability sand pack.

The mechanism for SMR is uncertain, but evidently depends on the microscopic blocking action of the foam bubbles, rather than on the macroscopic properties of the surfactant. Despite our lack of understanding of the details, we expect that on the average, the use of a proper CO_2-foam could nearly eliminate the mobility contrast between high and low permeability zones in reservoir flow, thus increasing markedly the efficiency of oil displacement. The above and earlier experimental research makes it clear that the SMR property of CO_2-foam is real, is observed in parallel-core tests with capillary contact, and can be presumed to function similarly in actual field situations. It should therefore be very useful in oil recovery from reservoirs containing crude oil of suitable[2,3] composition. The question remains, just how useful will it be, in an economic sense? The next section briefly discusses our work in attempting to answer this question by numerical simulation of simple field situations.

Displacements from layered reservoirs were simulated by use of Darcy's equation with the further aid of some assumptions: that the CO_2-foam displacing fluid drives the oil miscibly and that all of the

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*CD1045 and CD1050 were trademarks of the Chevron Chemical Company, which supplied this surfactant. They are now available from Chaser International, Inc. at 4640 Admiralty Way, Marina del Rey, CA 90292.

**Experimental surfactant X2001 was manufactured by Shell Chemical Company of Houston, TX. They no longer make it, and it is unfortunately unavailable.

heterogeneity of the reservoir is encompassed in the different permeabilities of the layers. Two simple geometries were used — linear, which might loosely represent the region between injection and production wells, and radial, representing the region surrounding an injector.

It is possible to represent the *degree* of SMR by the slope of the line, on a log-log graph, that represents the variation of mobility with permeability. In an analytic sense, the mobility of the CO_2-foam can thus be taken as proportional to the permeability raised to a specific exponent, which is the slope of that line. This is a useful first representation of SMR for a numerical model. If some particular foam showed no SMR and acted like an ordinary fluid, the exponent would be one (1). If the SMR were perfect (so that there was no variation of mobility with permeability), the exponent would be zero. Occasionally, a situation is found where the mobility actually decreases for higher permeability rocks. Over the range where that extreme case is observed, the SMR exponent would be negative. For our purposes, the above method is used to represent SMR in the computation, with the exponent usually lying between zero and one.

A set of programs, for the numerical simulation of the effect of SMR in a reservoir, has been written at the PRRC. These programs enable the comparison of CO_2 floods with and without the use of a mobility-reducing foam, and with and without the use of such a foam showing SMR. Different versions of the software examine the effects in either linear or radial geometry.

The results of this work show that the occurrence of SMR from foam made with the right kind of surfactant in the displacing fluid causes substantial increases in the rate at which oil is swept from reservoirs by a miscible phase like CO_2. The value of the increase depends on the amplitude of the SMR and on the extent of the permeability contrasts encountered in the reservoir.

The numerical results of these calculations are very encouraging, but are useful principally to show order of magnitude of the effect. In an actual reservoir where shape, well placement, and horizontal as well as vertical permeability variations must be accounted for, much more detailed and sophisticated reservoir simulation must be used. A way to enter the effects of CO_2-foam with SMR into commercial simulators would be to carry a variable mobility for the foam phase, in which foam mobility was determined in each CO_2-foam containing cell as a simple power of the cell permeability. We will endeavor to have such a modification made in those simulators that will be used in CO_2 flood prediction, so that operators can assess the value of SMR foam in their own application.

TASK 2: - REDUCTION OF THE AMOUNT OF CO_2 REQUIRED IN CO_2 FLOODING

During this quarter, a program has been developed to process the results that are generated by the reservoir simulators MASTER and UTCOMP. This is a spreadsheet program containing a series of macros that can be used to plot the flooding performance of a simulation run after it is done. There are converting programs associated with MASTER and UTCOMP so that the results generated by the simulators can be converted into a specific input format to the spreadsheet program.

In addition, the work on validation of foam options in MASTER has continued. The foam test that was used to validate the foam option in UTCOMP was used to validate the foam option in MASTER. In the initial tests, the results of the foam test are identical with the results of the base case without foam. These results are unexpected and are attributed to errors in the new code added to MASTER. Currently, we are debugging the foam option in MASTER.

The coreflood apparatus that has been used to examine the effect of surfactant concentration, gas quality, and flow rate has been down during this past quarter. The extended down time was required to completely replumb the system. Most of the valves and fittings had been etched severely by the corrosive behavior of the high salinity brine saturated with carbon dioxide. Currently, a new core has been put into the system and base case experiments are being run. The tests proposed during the next quarter will be performed to examine the influence of foam quality on CO_2-foam flow behavior at low CO_2 quality.

A conventional black oil PVT test on Sulimar Queen recombined reservoir fluid is being done for another project. The results of that study will also be useful for this study. Sulimar Queen oil is from a relatively shallow low temperature reservoir. This will be used as an example of a reservoir where the maximum achievable pressure would be at about the minimum miscibility pressure (MMP) or below it. This will be an excellent system to test recovery mechanisms at or below the MMP in a low temperature reservoir.

We have started revamping the minimum miscibility (slim tube) apparatus. During the next quarter, we will be running additional tests to refine the determined MMP of Spraberry oil and to determine the MMP of Sulimar Queen oil.

TASK 3 - LOW IFT PROCESSES AND GAS INJECTION IN FRACTURED RESERVOIRS

Research continues in two primary areas: 1) understanding the fundamentals of low interfacial tension behavior via theory and experiment and the influence on multiphase flow behavior and 2) modeling low IFT gravity drainage for application of gas injection in fractured reservoirs.

In the first year of our contract, we presented all the fundamental background for calculation of reservoir IFT of crude oil/gas mixtures. The calculation methodology developed was presented as a standard for industry use in predicting IFT accurately. Our methodology was based on certain assumptions concerning universal scaling laws. The assumptions have theoretical justification, yet there has been no established proof in the literature concerning the applicability of critical scaling exponents at conditions far from the critical point. We presented evidence for the conditions in our first annual report showing that the scaling exponents can apply far from the critical point. The first quarter of Year 2 was spent measuring IFT of pure component liquid/vapor systems in our completed pendant drop apparatus. We have presented experimental data in our previous quarterly report that supports the assumptions necessary for simple, yet theoretically accurate parachor calculations.

While continuing measurement of IFT of multi-component systems, we devoted the second quarter of Year 2 on CO_2/oil (non-equilibrium) gravity drainage experiments and mathematical modeling.

We have conducted a non-equilibrium gravity drainage experiment using Spraberry stock tank oil and CO_2. A sketch of the experimental apparatus is shown in Figure 1. In our experiment, a 4"x 24" Berea core (500 md) was first saturated with synthetic reservoir brine. Then, the brine was displaced by the oil to connate water saturation. During the gravity drainage process, CO_2 was injected into the annulus in the core-holder, and pressure and temperature in the coreholder were maintained about 1,400 pisa and 139°F, respectively. The volume of the oil recovery was collected at ambient conditions. The recovery curve is shown in Figure 2.

Figure 2 seems to reveal three stages of the drainage process: slow drainage due to viscous resistance (insufficient CO_2 content) at early time, accelerated drainage due to CO_2 content in an intermediate time, and slow drainage due to film flow after stabilization of the liquid-vapor boundary at later time. The experiment was terminated after ten days at which point the oil recovery is about 42%. This figure indicates that it may take a long time to get additional significant amount of oil from the core.

We have developed a new mathematical model for analyzing oil recovery under thermodynamic equilibrium conditions. By comparing with experimental data obtained from equilibrium conditions, we concluded that this new model gives significant improvement over existing models in literature. However, the new model fails to predict rate of oil recovery under non-equilibrium conditions. Figure 3 demonstrates the comparison between the equilibrium model calculation and experimental data. This figure indicates the need to understand non-equilibrium phenomena during gravity drainage. This is because the model does not account for the changes in fluid properties that occur when varying amounts of CO_2 exist in the oil during the multicontact process. There is no mathematical model available in the literature for describing the process of non-equilibrium gravity drainage. To simulate the gravity drainage under non-equilibrium conditions, we applied the model using a stepwise procedure as shown below:

(1) Estimate the concentration of the diffusing phase in each grid block at a diffusion/drainage time.
(2) Estimate fluid viscosity, density, IFT, and capillary pressure in each grid block at the time based on the composition of the fluid mixture.
(3) Apply the mathematical model to each grid block to estimate liquid recovery for each successive timestep.
(4) Sum up the recoveries calculated from each grid block to get the total liquid recovery at each timestep.
(5) Update the time by adding a time step and repeat 1, 2, 3, and 4 until a desired ultimate drainage time is reached.

We used viscosity and density correlations developed from similar fluid mixtures. Capillary pressure was calculated using Leverett *J* function and the IFT correlations presented in our first annual report. Figure 4 demonstrates the comparison of our experimental data with recovery curves calculated by the mathematical model. This figure clearly indicates that the use of the model and the stepwise procedure can match the experimental data. It is believed that the use of this stepwise procedure is effective for simulating a non-equilibrium gravity drainage process where gravity dominates flow of the wetting phase.

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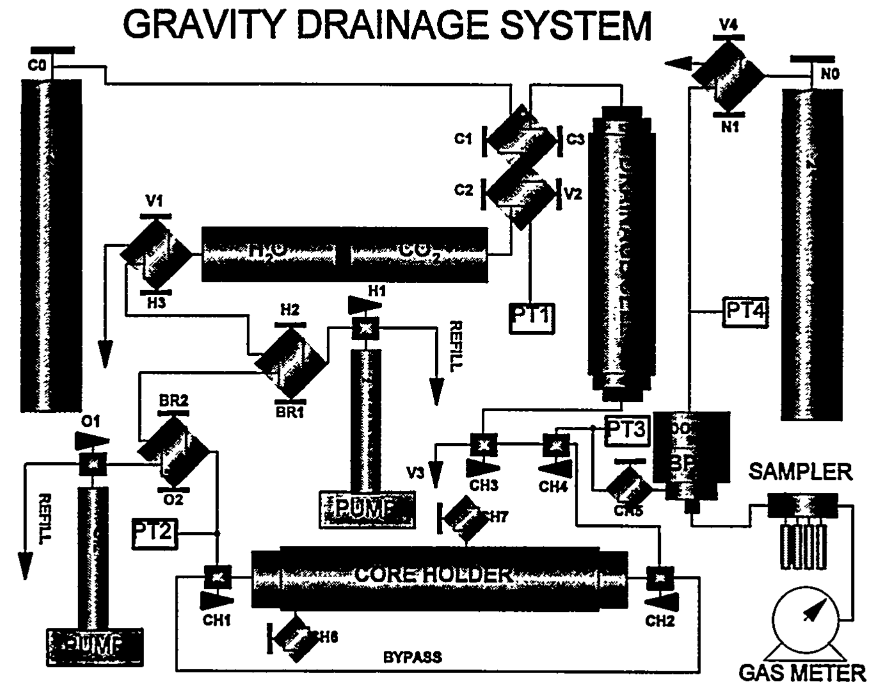

Fig. 1. Gravity drainage system.

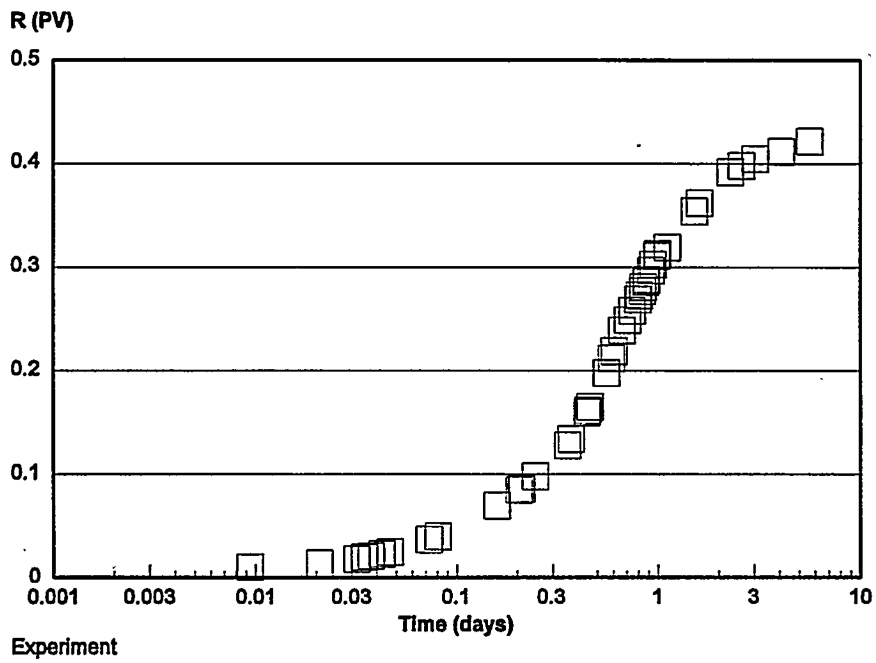

Fig. 2. Gravity drainage of Spraberry STO in 69 cm Long Berea core (500 md)
100% CO_2, T = 139 °F, P = 1400 psi.

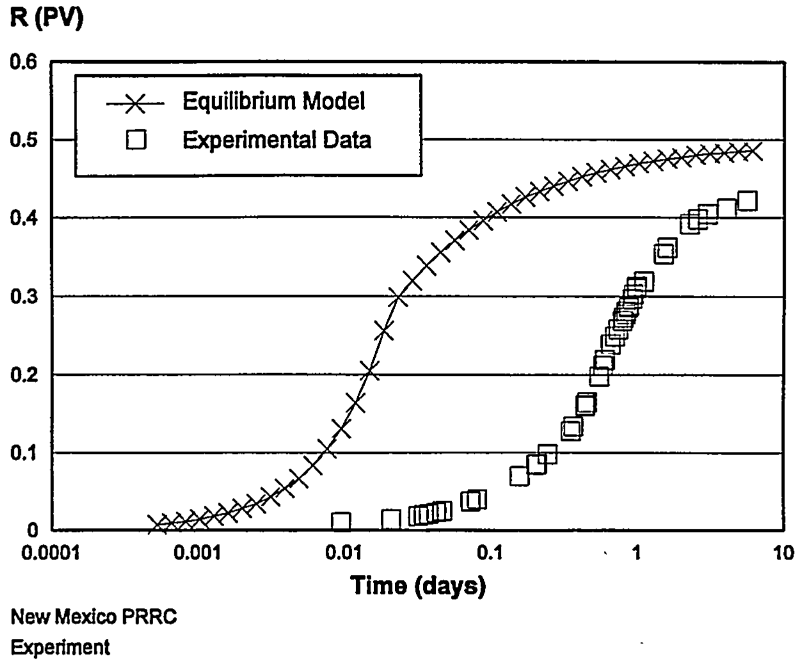

Fig. 3. Gravity drainage of Spraberry STO, experiment and Model-1 calculation
100% CO_2, T = 139 °F, P = 1400 psi.

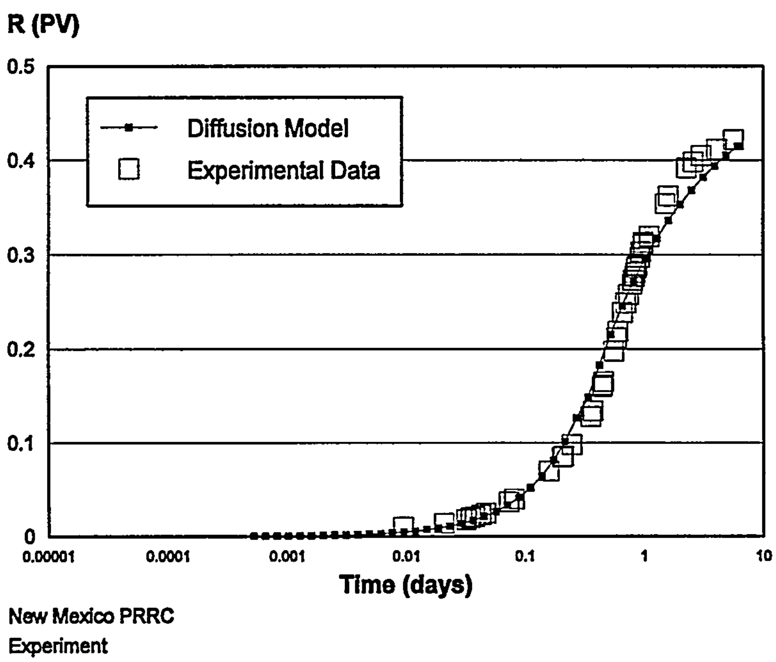

Fig. 4. Gravity drainage of Spraberry STO, experiment and Model-2 calculation
100% CO_2, T = 139 °F, P = 1400 psi.