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**RESERVOIR ENGINEERING RESEARCH
INSTITUTE**

Research Program on Fractured Petroleum Reservoirs

DE-FG22-93BC14875

October 31, 1995

Contract Date: September 30, 1993

DOE Program Manager: Dr. Robert E. Lemmon

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DOE/BC/14875 -- 3 Vol. 3

3Q.95

July 1 - September 30, 1995

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PROJECT 5 - SOLUTION-GAS DRIVE IN HEAVY AND LIGHT RESERVOIRS

Expansion Rate Effect on the Initial Stage of Gas Phase Formation in Supersaturated-Binary Mixtures

3Q.95

July 1 - September 30, 1995

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EXPANSION RATE EFFECT ON THE INITIAL STAGE OF GAP PHASE FORMATION IN SUPERSATURATED BINARY MIXTURES

Summary

The integral equation describing the nucleation and growth of bubbles in a supersaturated binary liquid mixture under constant expansion rate is considered. In case of macroscopically large number of microscopic nucleation sites, the solution is shown to exhibit weak dependence on the expansion rate in contradiction with experimental data. With few nucleation sites, the supersaturation extremum agrees with experimental data.

Introduction

Much attention has been paid recently to the problem of the new gas phase formation in supersaturated liquid mixtures.¹⁻¹⁰ The mechanism of new phase formation in a supersaturated liquid is generally expressed by the well-known theories of nucleation and growth.¹¹⁻¹⁴ While the dynamics of new phase growth in case of constant supersaturation in mixtures may not be complicated, the case of variable supersaturation appears to have non-trivial features.^{1,3,4} As an example, during the expansion of hydrocarbon mixtures, a pronounced dependency of critical supersaturation pressure on the rate of expansion has been observed.^{1,4} At the same time, the supersaturation decreases unabruptly beyond critical supersaturation pressure.

In a recent study, the integral equation which describes the pressure supersaturation evolution due to the nucleation and growth was investigated by Kashchiev and Firoozabadi.⁶ These authors assumed that the equilibrium pressure in the two-phase gas-liquid region remains constant. In most binary and multicomponent systems, the equilibrium pressure in the two-phase region varies with composition. In this study the supersaturation evolution for a binary liquid mixture with variable equilibrium pressure is considered. The liquid mixture is assumed to consist of a volatile and a nonvolatile component.

The content of this paper is divided in the following parts. First a general derivation of the integral equation describing the time evolution of su-

persaturation due to the bubble nucleation and growth is presented. Then a theoretical analysis of the initial stage of the new gas phase formation is offered. The paper is concluded with some remarks.

General Theory of New Phase Formation

Consider a binary liquid mixture of a volatile component b and the nonvolatile component a with number densities ρ^b and ρ^a , respectively. The system is assumed to expand isothermally with the steady expansion rate starting from some thermodynamic state in the stable liquid region.

Increasing the volume and thus decreasing the pressure, the liquid enters the supersaturated region wherein the system may split into the gas and liquid phases. We assume that the gas phase consists primarily of the volatile component. This assumption is valid for mixtures of, say, methane and hydrocarbons heavier than pentane away from the critical region⁴. The evolution of gas phase is determined by the bubble nucleation and growth. The growth is assumed to be governed by molecular diffusion.

The nucleation rate $J(t)$, which is the number of critical nuclei appearing per unit time per unit volume is given by

$$J(t) = A \exp[-W/k_B T], \quad (1)$$

where k_B is the Boltzmann constant, T is the absolute temperature, W is the minimum work required to create the critical size nucleus, and A is the preexponential kinetic factor. The factor A is proportional to the number of activation sites, upon which the new phase embryo can be nucleated. For homogeneous nucleation A is assumed to contain a factor of the order of Avogadro's number $N_A = 10^{23}$; for heterogenous nucleation, A is proportional to the density of foreign particles.

We present the minimum work W in the form of

$$W = k_B T B S^{-2}(t) \quad (2)$$

where $S(t) = [P_e(t) - P_L(t)]/P_o$ is the deviation of the pressure of the liquid phase $P_L(t)$ from the pressure of the equilibrium state $P_e(t)$, P_o is the saturation pressure at the initial time $t = 0$, and B is the thermodynamic parameter. Note that $P_e(t)$ and $P_L(t)$ have the same concentration, and $S(t)$ is a measure of supersaturation (see Fig. 1). For a single component fluid at

isothermal conditions, the equilibrium pressure, P_e , is a constant, but in a binary mixture it varies with time. The accounting of variable supersaturation for a classical nucleation rate expression, and growth is the main theme of this work. The validity of Eq. 1 for variable supersaturation is discussed in Ref. 6. Parameter B determines the nucleation barrier and is given by $B = (16\pi\sigma^3/3k_BTP_o^2)$ for homogenous nucleation, where σ is the surface tension. For heterogeneous nucleation, the value of B can be several orders of magnitude less than the homogeneous nucleation.

Let a bubble nucleated at moment t_1 occupy a volume $v(t | t_1)$ at moment t . Integrating over time previous to moment t , one obtains the expression for the volume fraction of the new gas phase S_G in the form of ^{6,16-18}

$$S_G = \int_0^t J(t_1)v(t | t_1)dt_1, \quad (3)$$

where $S_G = V_G/V_o$, V_G is the gas volume and V_o is the initial liquid volume. In Eq. 3 it is assumed that the volume of the liquid phase does not change. We relate S_G to the supersaturation by using volume balance, component molecular balance, and the equation of state for gas and liquid phases.

The total volume, V , at any time during the expansion is given by

$$V = V_o(1 + qt), \quad (4)$$

where q is the rate of expansion, which is assumed to be constant in this work. The total volume is also given by

$$V = V_L + V_G, \quad (5)$$

where V_L is the liquid phase volume and V_G is the gas phase volume. The total number of molecules of the volatile component N_o^b is given by

$$N_o^b = N_L^b + N_G^b \quad (6)$$

where superscript b denotes the volatile component b , N_L^b is the number of molecules of b in the liquid phase, and N_G^b is the number of molecules of b in the gas phase. Using the linearized equation of state, one can express supersaturation as the sum of external expansion and gas volume terms (see Appendix A)

$$S(t) = \tilde{B}_1 qt - B_2 S_G(t) \quad (7)$$

The value of positive parameters $\tilde{B}_1$ and B_2 for a given mixture can be obtained from an equation of state for the liquid phase.

To find $v(t | t_1)$, we describe the diffusion mechanism of the bubble growth. The molar concentration of the volatile component b in the liquid phase, $x^b = \rho^b / (\rho_L^a + \rho_L^b)$ obeys the stationary diffusion equation,¹⁹⁻²²

$$\nabla^2 x^b = 0 \quad (8)$$

Taking into account the boundary conditions, $x^b = x_L^b$ at $r \rightarrow \infty$ and $x^b = x^b(R)$ at $r = R$, where r is the distance from the bubble origin and R is the bubble radius, and x_L^b and $x^b(R)$ are the concentrations in the bulk liquid and on the bubble-liquid boundary, respectively. Solution to Eq. 8 can be presented in the form

$$x^b = x_L^b + \frac{R}{r} [x^b(R) - x_L^b]. \quad (9)$$

The flux of volatile component b towards the bubble is $-D(\delta x^b / \delta r) |_{r=R}$, where D is the diffusion coefficient. Writing the bubble material balance and using Eq. 9, one obtains the expression for the bubble growth due to diffusion,

$$\frac{dR}{dt} = \frac{D}{R} [x_L^b - x^b(R)]. \quad (10)$$

Assuming gas and liquid phases to be at equilibrium at the bubble boundary $x^b(R) = x_e^b$, and expressing the molar concentration through densities, Eq. 10 is transformed into (see Appendix B)

$$R \frac{dR}{dt} = x_L^b (1 - x_L^b) D (\rho_L^b - \rho_e^b) / \rho_o^b \quad (11)$$

where the subscripts e and o denote equilibrium, and initial state at $t = 0$, respectively. One can express the deviation of volatile component density from its equilibrium value appearing in Eq. 11 through the pressure supersaturation by (see Appendix A),

$$S(t) = \frac{\rho_L^b - \rho_e^b}{\rho_o^b} \tan \phi = \frac{P_e - P_L}{P_o} \quad (12)$$

where $\tan \phi$ describes the slope of the coexistence line plotted in $\{P_L^b/P_o^b, P_L/P_o\}$ coordinates given by (see also Appendix A),

$$\tan \phi = KC_a + C_b \quad (13)$$

Combining Eqs. 11 and 12, the expression for the bubble radius is derived:

$$R = R(t | t_1) = [2x_L^b(1 - x_L^b)D \int_{t_1}^t \frac{S(\tau)}{\tan \phi} d\tau]^{\frac{1}{2}} \quad (14)$$

In Eq. 14, the radius of the critical bubble is neglected. For constant supersaturation, Eq. 14 produces the well-known parabolic asymptotic of the form $R(t - t_1)^{\frac{1}{2}}$ (see Refs. 19 and 20). For non-spherical bubbles, through a shape factor α , which takes into account the deviation of the bubbles from the spherical shape, one may write $v(t | t_1) = \alpha R^3(t | t_1)$. For spherical bubbles, $\alpha = 4\pi/3$.

The closed integral describing the evolution of supersaturation due to nucleation and growth is obtained by combining Eqs. 1, 2, 3, 7, and 14

$$S(t) = \tilde{B}_1 q t - \alpha A B_2 [2x_L^b(1 - x_L^b)D / \tan \phi]^{\frac{3}{2}} \int_0^t \exp\left[-\frac{B}{S^2(\tau)}\right] \left\{ \int_{\tau}^t S(\theta) d\theta \right\}^{\frac{3}{2}} d\tau. \quad (15)$$

Note that in the above equation, supersaturation $S(t)$ at time t is determined from the previous values of supersaturation.

Theoretical Analysis of Initial Stage of the New Phase Formation

Let's define the dimensionless time as $\bar{t} = t/(\sqrt{B}/q\tilde{B}_1)$, and the renormalized supersaturation as $\bar{S} = S/\sqrt{B}$, then Eq. 15 is transformed to

$$\bar{S}(\bar{t}) = \bar{t} - C \int_0^{\bar{t}} \exp\left[\frac{-1}{\bar{S}^2(\tau)}\right] \left\{ \int_{\tau}^{\bar{t}} \bar{S}(\theta) d\theta \right\}^{\frac{3}{2}} d\tau \quad (16)$$

where $C = \alpha A B_2 \tan \phi^{-\frac{3}{2}} [2x_L^b(1 - x_L^b)DB]^{\frac{3}{2}} (\tilde{B}_1 q)^{-\frac{5}{2}}$.

Estimates of the preexponential parameter A even for homogeneous nucleation vary in a wide range 10^{27} to $10^{34} \text{ 1/(cm}^3 \cdot \text{s)}$. The order of magnitude for other parameters entering C include: $D \approx 10^{-5} \text{ cm}^3/\text{s}$, $B \approx 150$, $\tilde{B}_1 \approx 50$, $q \approx 1.3 \times 10^{-7} \text{ s}^{-1}$, $\alpha = 0.1$, $B^2 \approx 0.2\tilde{B}$, $\tan \phi \approx 1$, $x_L^b \approx 0.3$. These data are typical for the experimental data reported in Ref. 4. Thus for homogenous

nucleation we obtain estimates for parameter C in the range of 10^{30} to 10^{35} . Note that C is proportional to $q^{-\frac{5}{2}}$. Table 1 provides calculated maximum supersaturation, $\bar{S}_{max}$, and the corresponding t for various values of C . In these calculations, Eq. 16 was solved numerically. The numerical procedure of the integral equation is simple since the integrand in Eq. 16 contains $\bar{S}(\theta)$ for time $\theta \leq \bar{t}$. An iterative procedure can be easily implemented. In Fig. 2, the results for $\bar{S}(\bar{t})$ vs $\bar{t}$ are plotted. Both Table 1 and Fig. 2 reveal weak dependence of supersaturation on C for large values of this parameter. Let's assume $C_0 = 80$ and $q_0 = 1.3 \times 10^{-7} \text{ s}^{-1}$. The relationship between parameter C at other expansion rates q , is given by

$$C = C_0 \left(\frac{q_0}{q} \right)^{\frac{5}{2}}. \quad (17)$$

Fig. 3 provides the plot of pressure vs. volume expansion (i.e., $\bar{t}$) for four rates in physical units of Ref. 4. Parameter $B = 0.065$ was obtained as a fitting parameter to match the calculated critical supersaturation pressure with the measured value of Ref. 4. Parameter C permits to estimate the order of preexponential factor A . For the above mentioned values of various parameters $A = 1$ to 10 . Note that with low values of preexponential factor, the supersaturation rate dependency becomes strong.

Fig. 4 compares the calculated and measured pressure vs. volume expansion for two different rates. Note that there is a good agreement between the measured critical supersaturation pressures with the calculated values. However, the supersaturation pressure behavior at the later stage of expansion are not predicted accurately by the nucleation rate expression of Eq. 1. In a recent work, it is found that nucleation in porous media is of instantaneous nature. All bubbles are formed instantaneously and grow afterwards.²⁵

Conclusions

When the number of nucleation sites is large, the nucleation rate expression does not provide a strong dependence of supersaturation extremum on expansion rate. Comparison of the calculated supersaturation $S(t)$ plot, and measured data based on analysis of supersaturation extremum permits to determine parameters A , and B , of the nucleation rate expression. We observe that these parameters when are obtained by fitting the calculated supersaturation with data, are much smaller than those expected from the classical

nucleation theory. A similar order of magnitude for nucleation parameters was found earlier by analyzing experimental data.¹

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Appendix A

Let the equation of state (EOS) for a binary liquid mixture express the liquid pressure, P_L , as a function of number densities $\rho_L^a = N_L^a/V_L$ and $\rho_L^b = N_L^b/V_L$ of the two "a" and "b" components, respectively. In case of small deviation from the initial state at $t = 0$ with pressure P_o and number densities $\rho_o^a = N_L^a/V_o$ and $\rho_o^b = N_L^b/V_o$, we parameterize the equation of state in the form

$$\frac{P_L - P_o}{P_o} = C_a \left[\frac{\rho_L^a}{\rho_o^a} - 1 \right] + C_b \left[\frac{\rho_L^b}{\rho_o^b} - 1 \right] \quad (\text{A} - 1)$$

where parameters C_a and C_b can be computed from measured data or an equation of state such as the Pang-Robinson EOS²⁴.

From Eqs. 4 and 5, one obtains

$$(V_L/V_o) = 1 + qt - S_G(t) \quad (\text{A} - 2)$$

where $S_G(t) = V_G/V_o$. Then

$$\frac{\rho_L^a}{\rho_o^a} - 1 = \frac{1}{1 + qt - S_G(t)} \approx S_G(t) - qt. \quad (\text{A} - 3)$$

and,

$$\frac{\rho_L^b}{\rho_o^b} - 1 = -\frac{V_o}{V_L}[qt - S_G(t)] - \frac{\rho_G}{\rho_o^b}S_G(t) \quad (A-4)$$

where P_G is the gas density. For many fluid systems with a volatile component (i. e. methane), and a non-volatile component (i. e. decane), $V_o/V_L \approx 1$, and, therefore, Eq. A-4 simplifies to

$$\frac{\rho_L^b}{\rho_o^b} - 1 = -qt + S_G(t)[1 - X_G] \quad (A-5)$$

where, $X_G = \rho_G/\rho_o^b$.

Combining Eqs. A-1, A-3, and A-5 results in

$$\frac{P_L - P_o}{P_o} = -B_1qt + B_2S_G(t) \quad (A-6)$$

where $B_1 = (C_a + C_b)$, and $B_2 = C_a + C_b(1 - X_G)$.

The relationship between equilibrium pressure, P_e at volume V and the initial volume, V_o , is

$$\frac{P_o - P_e}{P_o} = \beta qt \quad (A-7)$$

where $\beta = \beta'V_o/P_o$, β' being the slope of the equilibrium line on the P-V plot (see Fig. A-1).

Combining Eqs. A-6 and A-7, and using the definition of supersaturation, $S = (P_e - P_L)/P_o$ results in

$$S(t) = \tilde{B}_1qt - B_2S_G(t) \quad (A-8)$$

where $\tilde{B}_1 = (C_a + C_b) - \beta$.

For the equilibrium process, Eq. A-1 becomes

$$\frac{P_e}{P_o} - 1 = C_a\left(\frac{\rho_e^a}{\rho_o^a} - 1\right) + C_b\left(\frac{\rho_e^b}{\rho_o^b} - 1\right) \quad (A-9)$$

Assuming that the solubility of the volatile component is a linear function of pressure, then one can write

$$(1 - \frac{P_e}{P_o}) = (1 - \frac{\rho_e^b}{\rho_o^b}) \tan \phi \quad (\text{A} - 10)$$

where ϕ is the slope of the line with $(P_e/P_o, \rho_e^b/\rho_o^b)$ coordinates. From Eqs. A-9 and A-10,

$$(\frac{\rho_e^a}{\rho_o^a} - 1) = K(\frac{\rho_e^b}{\rho_o^b} - 1) \quad (\text{A} - 11)$$

where $K = (\tan \phi - C_b)/C_a$.

One may also write an equation similar to Eq. A-10 for pressure P_L ,

$$(1 - \frac{P_L}{P_o}) = (1 - \frac{\rho_L^b}{\rho_o^b}) \tan \phi \quad (\text{A} - 12)$$

From Eqs. A-10 and A-13, we then obtain

$$S(t) = \frac{P_e - P_L}{P_o} = [\frac{\rho_e^b - \rho_L^b}{\rho_o^b}] \tan \phi \quad (\text{A} - 13)$$

Appendix B

The expression for $(x_e^b - x_L^b)$ is derived in the following. The molar concentration for component b in the equilibrium and non-equilibrium liquid phases can be defined as

$$x_e^b = \frac{\rho_e^b}{\rho_e^a + \rho_e^b} \quad (\text{B} - 1)$$

and

$$x_L^b = \frac{\rho_L^b}{\rho_L^a + \rho_L^b} \quad (\text{B} - 2)$$

Subtracting Eq. B-2 from Eq. B-1,

$$(x_L^b - x_e^b) = \frac{\rho^a(\rho_L^b - \rho_e^b)}{(\rho_e^a + \rho_e^b)(\rho_L^a + \rho_L^b)} \quad (\text{B} - 3)$$

Note that in the above expression $\rho^a = \rho_L^a = \rho_e^a$ since component "a" is assumed to be nonvolatile.

Multiplying Eq. B-3 by ρ_o^b/ρ_o^b , and assuming $\frac{\rho_o^b}{\rho_e^a+\rho_e^b} \approx x_b^b$, then

$$x_L^b - x_e^b = x_L^b(1 - x_L^b)(\frac{\rho_L^b - \rho_e^b}{\rho_o^b}) \quad (\text{B} - 4)$$

Table 1 - Calculated Supersaturation Maximum for Various Values of Parameter C

C	$\bar{S}_{\max}$	Corresponding $\bar{t}$
0.1	2.53	3.301
1.0	1.51	1.875
10	1.00	1.187
100	.74	.837
10000	.48	.525
10E6	.37	.388
10E8	.30	.313
10E12	.23	.237
10E20	.17	.175
10E24	.15	.151
10E28	.135	.137
10E32	.13	.135

Fig. 1 - Pressure-concentration phase diagram of a binary mixture. LL' and GG' represent lines of liquid and gas phases at equilibrium, respectively. The path from initial state of pressure P_0 and composition x_0 to the non-equilibrium state M at P_L and x_L^b are also shown schematically.

Fig. A-1 - Pressure-volume evolution plot.

Fig.2 - Pressure supersaturation vs. time

Fig.3 - Calculated pressure - volume evolution for different expansion rates

Fig.4 - Calculated and measured pressure - volume evolution
for two expansion rates

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PROJECT 6c -WATER INJECTION IN FRACTURED/LAYERED
POROUS MEDIA

An Experimental Study of Water Injection Performance in
Very Tight Rock Matrix

3Q.95

July 1 - September 30, 1995

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SUMMARY

In a large number of fractured and layered reservoirs, tight matrix rock may contain a significant amount of oil. The contribution of the tight matrix in fractured petroleum reservoirs and of the tight layers in layered reservoirs is an unresolved issue. In this work, the results of three water displacement tests for a rock matrix with a permeability of the order of 0.01 md and a porosity of about 5 percent are presented. All three experiments reveal that a recovery of around 20-25 percent can be achieved in a period of 1-4 months. At the termination of all the tests, the rate of oil production from the tight matrix was about 0.2-0.3 percent of PV per day.

INTRODUCTION

A large number of fractured petroleum reservoirs comprise tight matrix blocks and fractured networks. Many layered reservoirs also contain tight layers. The thickness of the tight layers can vary from less than one ft to 10 ft or more. The permeability of the tight rock can be of the order of 0.01 md and the porosity can vary from 3 to 10 percent. The fundamental issue is the contribution of the tight matrix in fractured reservoirs and the tight layers in layered reservoirs. Current literature, in most cases, neglects the contribution of the tight matrix.

The purpose of this work is the study of water displacement efficiency in layered and fractured reservoirs with tight layers and tight matrix, respectively. Part 1 of the project addresses the issue of water injection in fractured reservoirs with tight matrix. With 3 experiments, the experimental work for Part 1 is complete. Analysis of the experiments is the next step. Part 2 of the work will be planned later.

EXPERIMENTAL

Apparatus: A schematic of the experimental apparatus is shown in Figure 1. The setup consists of a steel coreholder 45 in in length with an external diameter of 4.0 in and an internal diameter of 3.366 in. Six core samples, all with finely machined external diameters of approximately 3.363 in, of varying lengths are held in place in the coreholder with pistons and threaded endcaps. The coreholder is oriented vertically. Plumbed to the bottom of the coreholder is an Isco constant flowrate syringe pump. The effluent from the core passes through the top endcap, which is connected to a tube which terminates in an inverted graduated cylinder, used for measurement of the amount of oil produced. Connected in parallel to the injection and production lines is a system for evacuating the coreholder.

Test Procedure: The coreholder was assembled with Austin chalk cores #1-6 in descending order. Table 1 gives the dimensions, porosities, permeabilities, and pore volumes of the cores. The total pore volume for the cores is around 287 cm³. The fracture PV around the matrix is estimated as 4 cm³, and the effective permeability of the combined matrix/fracture system was measured as 150 md using liquid nC₆.

The system was placed under vacuum and heater tapes were applied to the coreholder to assist in desorption of nitrogen and air from the cores. The coreholder was heated to approximately 140°F and the system was evacuated at a pressure of 50 mTorr for about two weeks. The system was then saturated with nC₆ in Tests 1 and 2, by first filling the isolated Isco pump and then injecting the liquid into the coreholder. Saturation was performed stepwise. After an initial large injection of liquid, small volumes were injected, causing the

system pressure to rise. This increase in pressure aided in saturating the smallest pores of the rock. A total of about 300 cm^3 of nC_6 was used to saturate the system over a one week period. The injection water was prepared by grinding up a spare piece of chalk into pebble size chunks, placing these in distilled-deionized water at a ratio of 1 g rock/ 100 cm^3 water, and allowing 10-20 days for equilibration. This was done to prevent the dissolution of the core samples during the water injection experiment. Water injection was initiated 2 weeks after the saturation step for Tests 1 and 2. In Test 3, the core assembly was saturated with a mixture of nC_6 and crude, and water was injected after 3 weeks of the saturation step. All the tests were conducted at a room temperature of about 75°F .

RESULTS

A total of three successful tests were performed. The results are presented in the following.

Test 1-- $2 \text{ cm}^3/\text{hr}$ Injection Rate: The rate of water injection in the first waterflood experiment is approximately $2 \text{ cm}^3/\text{hr}$. The production of nC_6 is plotted in Figure 2. The plot shows that during the initial hours nC_6 production follows the injection rate. At an injection volume of about 19 cm^3 , a sharp change in the slope of the curve occurs. This corresponds to the water breakthrough point. After this point, nC_6 is produced at a rate of approximately $2 \text{ cm}^3/\text{day}$. At 336 cm^3 injection, water injection is stopped and imbibition is allowed to proceed about 8 days. Then water injection is resumed. Once again, production of pure nC_6 occurs for approximately 5 hours until water breakthrough occurs, after which a reduced rate of nC_6 production is seen. At 720 cm^3 injection, water injection is again halted to allow for imbibition. After 9 days of imbibition, the water flood is resumed. This is followed by a short period of pure oil

production (3 hr) and subsequent return to even slower production of nC_6 at a rate of about $0.7 \text{ cm}^3/\text{day}$. After a third imbibition period of 8 days, 3 cm^3 of nC_6 is produced in the first 8 hours following the start of reinjection, with the production rate then falling to about $0.2 \text{ cm}^3/\text{day}$. The total amount of nC_6 produced is about 62 cm^3 , which is approximately 21% of the initial oil present, but it requires an imbibition period of 50 days (1200 hr).

After completion of the experiment, the fracture volume/dead space of the system was measured. It was found that the narrow tolerances between the outer diameter of the chalk samples and the inner diameter of the coreholder created a situation where a minimal amount of liquid flowed from the system when both sides were opened to atmospheric pressure (gravity flow). The 0.003 in nominal difference in diameters corresponds to a fracture gap of $38 \text{ }\mu\text{m}$. Nitrogen, at a pressure of about 30 psig, was applied to the outlet of the coreholder to assist the drainage of the fractures. About 4 cm^3 of the liquid were produced.

Test 2-- $3 \text{ cm}^3/\text{hr}$ Injection Rate: Test 2 is similar to Test 1 with an injection rate of $3 \text{ cm}^3/\text{hr}$. The production of nC_6 is plotted in Fig. 2. This figure reveals that the results from Tests 1 and 2 are similar. Test 2 was terminated after injecting 660 cm^3 of water.

Test 3-- $2 \text{ cm}^3/\text{hr}$ Injection Rate: In this test, about 1 wt % of a 35 API crude was added to nC_6 . According to Salathiel¹, when a small amount of a crude is diluted into the normal alkanes such as nC_6 and nC_7 , waterflood performance may become essentially the same as that of the original reservoir crude.

Fig. 2 shows the results for this test together with the results from Tests 1 and 2. Fig. 3 depicts the results for Test 3 only. In the first 9 hours, about 18 cm^3 of the nC_6 /crude mixture is produced. After water breaks through, similar to

the first two tests, the oil production decreases substantially. After water injection of 300 cm^3 , the injection is stopped, and the system is allowed to undergo imbibition for 10 days. Then the injection is resumed; about 5 cm^3 of pure oil is produced, after which two-phase production begins. The injection is stopped after 520 cm^3 of the water injection. The period of injection stop is 15 days; then injection starts. In the subsequent imbibition steps, the duration is also 15 days. The test is terminated after 128 days. Total production of oil during the entire period is 72 cm^3 , which is about 25 percent of oil in place.

CONCLUDING REMARKS

The above experiments have established that very tight matrix could contribute to recovery. Test 3 duration exceeds 4 months but the life of a field is even longer. The oil production from the tight rock used in the above experiments is capillary driven. Analysis of the data, which is the next step, may lead to the understanding of the process and the scaling of the experiments.

REFERENCE

Salathiel, R. A.: "Oil Recovery by Surface-Film Drainage in Mixed-Wettability Rocks," JPT (1987) 1216.

Core #	L (in)	k (md)	ϕ (%)	PV (cc)
1	7.290	0.012	4.8	51.33
2	5.830	0.017	4.7	40.10
3	7.100	0.034	4.8	49.99
4	6.120	0.007	5.3	47.10
5	6.028	0.042	4.7	41.46
6	7.875	0.013	5.0	56.74

Table 1: Austin Chalk Samples

Figure 1: Austin Chalk Experiment Setup

Figure 2: Austin Chalk Waterflood Performance

Figure 3: Waterflood Performance of Austin Chalk Test 3

Reservoir Engineering Research Institute

**PROJECT 6c - WATER INJECTION IN FRACTURED/LAYERED
POROUS MEDIA**

**Experimental Study of Water Injection Performance of Fractured
Porous Media**

2Q.95

April 1 through June 30, 1995

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SUMMARY

The results of three tests for water injection in a fractured system consisting of 12 matrix slabs have been very promising. Both the rate of oil production and the recovery factor exceed the gas-oil gravity drainage results for the same system.

INTRODUCTION

In some fractured reservoirs, the recovery from water injection has been very efficient. The performance of a fractured reservoir to water injection, to a large extent, depends on the matrix capillary pressure including the residual oil to water at high negative capillary pressures. In both fractured and layered reservoirs, capillary pressure could provide an excellent driving force, depending on dP_c/dS_w and on the magnitude of capillary pressure contrast between the two media¹. In this report, the results of three experiments on waterflood efficiency in fractured porous media are presented.

EXPERIMENTAL

The fractured porous media used for the experimental investigation consists of a stack of 12 Berea slabs, three layers of four blocks in each row. Fig. 1 shows the matrix slabs and the configuration of the fractured porous media. All the matrix slabs are aligned in the same direction. The porosity of the matrix slabs is approximately 22% and the fracture volume between the slabs and between the slabs and glass is estimated to be 50 cm³. The permeability of the slabs is 700 md, and the effective permeability of the combined matrix/fracture

system is measured to be 5.5 darcy. The core system is enclosed by glass plates on the sides, and on the top and bottom are aluminum plates with many holes to distribute the flow into and out of the system evenly. The configuration of the slabs is identical to that previously used in miscible displacement experiments². Plumbed to the bottom of the core is an Eldex B-100-S chromatography pump, used for the water injection. The top of the system is connected to a tube which terminates in an inverted graduated cylinder used for measuring the production of the oil phase. A video camera/VCR system is used to record the measurement. A diagram of the apparatus is shown in Fig. 2.

The core system was evacuated at approximately 100 mTorr for a week prior to saturation with normal decane (nC_{10}). The pore volume of the system measured via volume of nC_{10} used for saturation is estimated to be 8800 cm³. The brine used for displacement consists of 1 wt% NaCl and distilled water.

RESULTS AND OBSERVATIONS

A total of three tests were performed. The only difference between these tests is the injection rate.

Test 1: The injection rate used for Test 1 is approximately 150 cm³/hr. A plot of the volume of nC_{10} produced versus the volume of brine injected is shown in Fig. 3. From the plot it can be seen that the production for oil follows the injection rate up to a volume of about 4200 cm³ (~28 hr), where water and oil are seen in the production line. This is when water breakthrough occurs. Therefore, the recovery at breakthrough is around 48%. A transition period occurs for the next 20 hours, when the oil production rate continues to decrease to a steady state rate of 6 cm³/hr. The cumulative oil production at this time is about 5000

cm³ (or 57% PV). At an injection of 15000 cm³ (~1.7 PV) water, the injection was curtailed and imbibition was allowed to proceed for about 3 days. The water injection was then resumed. A brief period of pure nC₁₀ production (~30 cm³) was observed, after which the system returned to a very slow production rate.

Test 2: The injection rate for this test is about 200 cm³/hr. The volume of nC₁₀ produced versus the volume of brine injected is also shown in Fig. 3. This figure reveals that the results from the two tests are very similar. For Test 2, the production of oil follows the injection rate up to a volume of about 4200 cm³ (~21 hr), where water breakthrough occurs. In the two-phase production period of the next 15 hours, the oil production rate continued to decrease to a steady state rate of about 6 cm³/hr. The cumulative production at this time is about 5000 cm³ (~57% PV), which is the same as Test 1. At an injection of 18200 cm³ (~2 PV) water, the injection was curtailed and imbibition was allowed to proceed for about 4 days. The water injection was then resumed. A brief period of pure nC₁₀ production (~28 cm³) was observed, after which the system returned to a negligible production rate.

Test 3: The rate of water injection for Test 3 is 500 cm³/hr. The results are also shown in Fig. 3. Water breakthrough for this run takes place after about 3 liters of oil production, and unlike the two previous runs, after water breakthrough, appreciable amount of oil is continuously produced until about 5 liters of oil has been produced. After that the oil production rate drops quickly (see Fig. 3).

To test if imbibition of high water saturation will affect water injection performance, the injection is stopped at 15 liters of water injection. After 9 days, the water injection is resumed. Water breaks through quickly and oil production is very limited.

CONCLUDING REMARKS

Comparison of the results of water injection recovery performance presented in Fig. 3 and the gravity drainage results for the same aggregate of matrix slabs show in Fig. 4 reveal that water displacement is much more efficient. In our previous work³ we have analyzed the gas-oil gravity data presented in Fig. 4. Capillary pressure contrast between the matrix and fractures causes the slow down of the rate in the drainage process. We would also analyze the water displacement experiments presented in this report to understand the process. However, before doing that, we need to measure imbibition relative permeabilities and imbibition capillary pressure. Work toward this end is in progress.

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Figure 1: Berea Slabs Geometry

Figure 2: Stacked Blocks Experiment setup

Figure 3: Waterflood Performance of the Stacked Blocks

Fig. 4 - nC_{10} Produced v.s. Time for Gravity Drainage