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**FLUID FLOW BEHAVIOR THROUGH ROCK-SLAB MICROMODELS
IN RELATION TO OTHER MICROMODELS – TOPICAL REPORT**

By
Syed M. Mahmood

June 1990

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IIT Research Institute
National Institute for Petroleum and Energy Research
Bartlesville, Oklahoma

**Bartlesville Project Office
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Bartlesville, Oklahoma**

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

Robert E. Lemmon, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
IIT Research Institute
National Institute for Petroleum and Energy Research
P. O. Box 2128
Bartlesville, OK 74005

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FLUID FLOW BEHAVIOR THROUGH ROCK-SLAB MICROMODELS IN RELATION TO OTHER MICROMODELS

By Syed Mahmood

ABSTRACT

A new technique was developed to visualize fluid movement and rock/fluid interaction in the pores of reservoir rocks. It consists of fabricating micromodels containing rock slabs of 3 millimeter thickness and using sensitive image acquisition, recording, and enhancement systems to perform time-and-motion analyses of high-speed events.

Displacement experiments were performed using these rock-slab micromodels and two other types of micromodels: an etched-glass network model (HEG) and a chemically consolidated grain-packed (cryolite) model. The tests included several cycles of imbibition and drainage. Comprehensive steady-state tests were also performed in the two simplified (HEG and cryolite) models, which included two-phase and three-phase flows with gas/water, oil/water, and gas/oil/water systems. The results were compared to understand the scope and limitations of these micromodel techniques.

The interesting observations are summarized as follows: (1) Behaviors in the simplified models were very sensitive to operating conditions; (2) end effects and fluid redistributions were not evident; and (3) many observations differed from those with the rock-slab micromodel. Another important feature of the rock-slab micromodel was the absence of fluid by-passing at confining surfaces (boundary effects), which usually distorts the true mechanisms.

Several interesting pore-level events occurring in the pores are shown and explained in this report, many with the help of sequences of photographs, adding to the understanding of these complex phenomena.

INTRODUCTION

The pore network in most reservoir rocks is complex. The pores are heterogeneous in size, geometry, and connectivity; and the spatial variation is generally random. Quite often, the wettability of the grains is also nonuniform. The microscopic sizes of the pores and throats render strong capillary forces. When two or more fluids are present in porous media, their motion and distribution are governed by complex interactions of viscous, gravitational, and capillary forces and are highly influenced by the microstructure of the pores and throats, which vary from one pore to another.

Describing the flow of fluids through porous media by theory alone is difficult. To model multiphase flow accurately for predicting oil recoveries or estimating irreducible oil saturations, a realistic understanding of the pore-scale fluid distribution and displacement (or flow) behavior at several saturation levels is required.

Flow mechanisms have been observed previously through microvisual models and by indirect destructive techniques, such as solidifying in situ fluids in a core sample and then gradually cutting from one end of the core to observe fluid distribution. Several useful studies have been described in a recent literature review.^{1,2} Both methods have several limitations. It is difficult to replicate the complex pore geometry and wetting characteristics of rocks by relatively simple two-dimensional pore/throat networks in typical transparent models. Since the pore structure dictates the motion and distribution of fluids within porous media, it is difficult to obtain similarity in microscopic behavior by using simple network micromodels.

Indirect techniques, such as solidification of fluids in situ, can be used to re-construct the three-dimensional nature of pore networks. However, the epoxy resins used for this process do not have surface and interfacial characteristics similar to those of reservoir fluids. Changes are also likely during solidification of fluids due to chemical reactions and during the cutting process due to the intense mechanical action, generated heat, and use of cutting fluid. Thus, caution has to be exercised when interpreting results from applications of these methods.

Micromodels have also been used frequently for understanding the pore-level effect of additives, such as solvents, thickeners, surfactants, blocking agents, alkaline solutions, and microorganisms.^{3,22} The need for improvement in the techniques still exists for realistic pore-structure representation to accurately model these phenomena.

This study was undertaken to improve the understanding of multiphase flow using more realistic pore-scale models. In the first phase of this study, available micromodel techniques were

improved and suitable video-microscopy equipment was assembled. Several types of micromodels were also fabricated which retain essential characteristics of reservoir rock; that is, the pore diameter, the coordination number or connectivity (number of connections leading from a pore to its adjacent throats), and pore/throat geometry. The technical and operational details of existing micromodel techniques and three new techniques developed in this project were previously reported.¹

In the second phase of this project, these micromodels were used to perform multiphase flow experiments. Results from these flow experiments are presented in this report.

Literature Review

An extensive literature search was carried out¹ to evaluate the published techniques, their relative merits, and the information derived from these models. Following is a brief outline of the techniques and their roles. The techniques which use rock slabs are discussed in more detail because of their ability to simulate pore structure more realistically.

Visual microscopic studies under established and controlled boundary conditions have helped in providing a better understanding of basic parameters that affect oil-displacement mechanisms in porous rocks. Among other applications, visual models have been utilized for mechanistic studies to verify the description of a given process or to illustrate and identify unknown mechanisms. For example, such models have provided insight into capillary and surface phenomena; the pore level distribution of fluids; and the isolation, trapping, or mobilization of oil by other fluids.

Efforts have been made to develop techniques to visualize flow and fluid distribution in porous rocks at the microscopic level. Since the beginning of flow visualization experiments in the 1920s,²⁻⁴ several types of visual models for simulating pore characteristics have been developed.⁵⁻¹⁹ The most common (conventional) models used are capillary tube, bead/sandpack micromodel, and network micromodel. Each of these models has unique advantages and distinct limitations in design, fabrication, and operation.

Capillary tube models are idealized pore models and do not adequately represent real porous media. Bead/sandpack micromodels do not permit adequate visualization of the movement of interfaces, and static distribution is also difficult to observe. Furthermore, their pore shapes cannot be varied at will, because the beads have to be uniform.

Network micromodels are, in essence, two-dimensional flow cells that represent an idealization of the pore network in a rock. They have a network of flow channels etched in transparent material to enable the observation and recording of the movement of fluids as displacement occurs. This generation of micromodel has been used since the early 1960s to study fluid flow behavior in porous media. Techniques for fabricating some of these micromodels and studies utilizing these micromodels were reported previously.¹

All studies described previously were based on the assumption that micromodels provided only an approximate idealization of the complex pore structure present in reservoir rocks. In contrast to micromodels, real porous rock consists of interconnected three-dimensional networks of voids, pores, and throats that have irregular geometry. Because of the insufficient understanding of the phenomenon of flow through porous media, it is extremely difficult to decide which features of the real rock are essential in micromodels. Micromodels containing real reservoir rocks are needed to outline important parameters.

Few studies have been reported²⁰⁻²¹ in which visual observations were made through a micromodel containing a thin section of natural reservoir rock. American Petroleum Institute Research Project 47b, as presented by Chatenever,²⁰ was begun under the title "Microscopic Behavior of Fluid in Porous Systems." The project was continued for 6 years, ending June 30, 1955. Two types of micromodels were used: an idealized micromodel composed of a single layer of uniform glass spheres packed between two glass plates; and a thin section micromodel having a slab of rock sliced thin enough to allow enough passage of light for visual observations. The study concluded that between the two micromodels lies a significant gap. It advised not to consider the experimental findings in glass-sphere micromodels as reliable for application to the field until the gap is properly bridged. Nevertheless, the study resulted in describing flow mechanisms which are the basis of the present understanding of fluid flow in porous media.

Gring and Caudle²¹ followed the same approach as the API 47b project to investigate waterfloods in a microlayered sandstone. The thickness of the micromodel used in their studies was about 0.5 millimeter. They concluded that the use of thin slices of porous media for macroscopic flow visualization was practical. However, no mention was made of pore-scale visualization. Even though work using this type of micromodel was recommended by those two studies, no further work has been reported.

EXPERIMENTAL EQUIPMENT AND MICROMODEL FABRICATION TECHNIQUES

In this work, the experimental set-up consisted of a modified geological microscope (Nikon, Optiphot and UFX-11), a powerful fiber optic light source, a sensitive high-resolution monochromatic camera (Plumbicon tube, 0.005 lux, 900 TV-lines), and a super-VHS VCR (450-lines).¹

The three micromodels used in this study were HEG, cryolite, and rock-slab. The HEG model, an abbreviation of heterogeneously etched-glass model, was fabricated by photo-chemically etching a thin-section image (magnified) of a Berea sandstone on two glass plates, which were thermally fused together to provide flow networks.

The cryolite model was fabricated by packing crushed cryolite grains between two glass plates and sealing the boundaries with epoxy to confine the flow to the cryolite matrix. The model was then treated with a series of chemicals, which caused the cryolite grains to bond with each other and to the confining glass plates, forming a consolidated cryolite matrix.

The rock-slab model consisted of an actual rock slab of 3 millimeter thickness, sandwiched between two plexiglass plates. Gaskets were used to confine the flow to the rock, whereas a coating of soft and transparent silicone rubber was applied to eliminate by-passing through the adjoining rock/plexiglass surfaces.

As previously mentioned, the fabrication technique for each of these three micromodels has been described.¹ The physical properties of these models are listed in the following sections of this report.

CLEANING AND INITIAL SATURATION WITH BRINE

During the fabrication process, no oil or organic solvents were introduced to avoid wettability changes. Attempts were made to saturate the model fully with brine, but except in rock-slab models, some gas was always seen trapped in microscopic examinations. Serious difficulties were encountered in complete removal of gas from the model in order to saturate it fully with brine. Evacuation, use of CO₂, etc. were all found to be inadequate. The trapped-gas saturation was minimized by displacing air with CO₂, performing several cycles of evacuation followed by brine injection, and finally, injecting large volumes of brine.

The gas was generally trapped in the form of globules much smaller than the pores; thus the trapping did not appear to be due to constriction, but rather to viscous bypassing in the pore. One reason might be the weak affinity (or spotted wettability) and capillarity of these models for brine. Visual observations suggested that pressuring this model would have reduced or completely eliminated trapped gas since the gas globules were seen to compress and deform as pressure was increased releasing some of the trapped gas. Also, such a practice would have caused some of the gas to dissolve in brine, especially if it were CO₂, thus further reducing gas saturation. It appears that saturation procedures involving high pressures may be superior for core saturation.

OBSERVATIONS IN HETEROGENEOUSLY ETCHED GLASS MODEL

Model Description

This model was fabricated by photochemically etching a thin-section image (magnified) of a Berea sandstone on two glass plates, which were thermally fused together to provide flow networks. The pore volume was 0.19 cm³, porosity was 16%, and liquid permeability was about 18 darcies. The depth of the pores was varied across the direction of flow, with an average of 230 microns in the center. During the course of the tests, the model was exposed to a maximum positive pressure of 30 psig and a total pressure differential of 45 psi when also evacuated.

Electrical resistivity measurements were made at different brine saturations to be able to determine brine saturations during flow tests. A resistivity index vs. saturation plot was drawn. Electrical resistivity parameters m (cementation exponent), n (saturation exponent), and F_R

(formation resistivity factor) in Archie's equations $\left(F_R = \frac{1}{\phi^m} \text{ and } RI = \frac{1}{S_w^n} \right)$ were 1.4, 4.7, and 12,

respectively. The high saturation exponent (n) value for this less tortuous model may suggest a preferentially oil-wet system; however, visual observations showed it to be water-wet.

Gas/Water Unsteady-State Drainage Test

Gas was injected in the model to displace brine at a nominal rate of 0.24 cm³/hr (equivalent frontal velocity = 8.4 ft/day). Gas first invaded the zones mostly containing larger-size channels, but as the displacement progressed, the zones of smaller-size channels were gradually swept. However, at every

residual brine saturation level (which depended on rate), some smallest-size channels always remained unswept by gas.

The above explanation seemed valid only when observations were made at model scale. The pore level behavior was quite contrary. When the gas first invaded the zones mostly containing larger-size channels, most of the channels were swept in this zone irrespective of the size. Thus, gas invaded the networks of pores and throats that offered the least overall (combined) resistance. In addition, later observations indicated that the sequence of networks swept by gas was somewhat random, perhaps because many combinations of channels offering similar resistance were possible.

Gas/Water Unsteady-State Imbibition Tests

To determine the role of hysteresis, brine was injected in the model containing gas and irreducible brine saturation at a rate similar to that of the above test. Unlike the drainage cycle, the brine first invaded in the zones containing larger-size channels. Quite soon, brine invasion into larger-size channels caused the gas in these channels to become discontinuous, which caused the gas flow to become complex. Intermittently, these gas slugs extending to several pores moved from one network to the other, coupled with the flow of brine slugs. The gas slugs coming close to each other coalesced, and because of the growth in size, a certain volume of gas was dissociated and flowed in the form of small bubbles. This type of in situ flow resulted in slug-type production at the outlet port, containing slugs of nonuniform and variable sizes.

Gas/Water Steady-State Tests

Four tests were performed in which gas and brine were concurrently injected using syringe pumps. The brine injection rate for these tests was $0.32 \text{ cm}^3/\text{hr}$ (equivalent frontal velocity = 11.2 ft/day). The gas injection rate was different for each test: 0.34 , 1.4 , 13 , and $42 \text{ cm}^3/\text{hr}$ (equivalent frontal velocity = 12 , 50 , 450 , and $1,500 \text{ ft/day}$). Flow behavior was recorded during transient as well as steady-state conditions, both at pore and model scales. The saturation at each stage was determined by the electrical resistivity technique.

In all tests, fluid production was in the form of discontinuous and nonuniform slugs; that is, the flow would cease, the injection pressure would build up, and eventually, production would surge. This behavior was observed even 24 hours after macroscopic fluid distribution was stabilized. The surges in electrical resistivity values (e.g., by 30%) related well with the production behavior. Obviously, the compressibility of gas played an important role in allowing this type of behavior, especially because the gas was being injected using a syringe pump.

Pore-scale visual observations explained the production behavior very well. Three distinct cycles were observed: pressure buildup, brine flow, and gas flow. A possible explanation of cyclic flow is as follows. Gas, being the nonwetting phase, does not enter the pores until viscous forces become larger than the capillary forces; that is, the pressure exceeds the threshold. As the pressure builds up, gas invasion in the pores begins, along with brine displacement from the channels. During this stage, brine is the primary product. Continuous gas channels are eventually formed, and gas then becomes the primary product. As the pressure of the gas phase is depleted, the capillary forces become dominant again; thus, water imbibes in the throats and smaller pores, making the gas channels discontinuous. However, by this time, these discontinuous gas blobs occupy most of the flow channels. Microscopic examination during this stage revealed that virtually all of the brine flow was taking place through surface films and gas-brine boundaries, while encountering high resistance. This is the duration in which the pressure of the gas phase builds up.

Some other interesting observations are as follows. Whereas gas was seen to form continuous channels from inlet to outlet ports periodically in a cyclic manner, brine channels were never seen to be continuous. Brine channels were broken by gas blobs sandwiching brine between them. Nevertheless, brine crossed these gas barriers by flowing through the interfaces. The gas globules were seen to be expanding, contracting, and moving from one pore to another. Gas did not necessarily invade the larger pores; rather, it invaded zones of least resistance.

Oil/Water Unsteady-State Drainage Test

In these tests, oil (2.5 cP) was injected to the fully brine-saturated model at a rate of 0.34 mL/min (10 ft/day) until brine saturation was reduced to residual. Oil usually advanced in the center of the channels leaving water on the surfaces, indicating the model to be water-wet. Oil invaded first through the zones offering lowest overall resistance. Oil continued sweeping zones of higher and higher resistance as oil throughput increased and/or as the rate was increased until water production stopped.

In the zones swept by oil, water remained in the form of small pockets which were isolated due to the oil invasion. On a microscale, however, the size of a channel was not a determining factor as to which fluid was saturating it. Thus oil, even though a nonwetting phase, was seen frequently to fill channels smaller than those containing water. This may be an indication of inaccessible pore system, but the imaging system in use did not have the capability to resolve this.

At residual water conditions, water remained on interstices and in by-passed pores, throats, channels, small pockets; and larger zones. However, the saturation and distribution of this trapped water were not absolute, as some of the trapped water became mobile on increasing the pressure gradient. This pore-scale mobility was in the form of small slugs and lamellae detaching from the existing water body and jumping to the adjacent bodies to coalesce. In this fashion, some additional water was produced.

Oil/Water Unsteady-State Imbibition Test

For this test, the saturation conditions were the same as those resulting after the drainage test described above; that is, the water was immobile and at irreducible saturation. Water was injected at the same rate as above (0.34 mL/min, 10 ft/day).

Upon the start of injection, water primarily transported through a group of adjoining channels and tended to take a somewhat straight path between the injection and production ports-- the path of highest pressure gradient. But it also flowed through the interstices increasing the thickness of interstitial water layers. Smaller throats were first filled with water, and the fillup continued in larger and larger channels. When all the throats surrounding an oil entity were filled, the oil became trapped.

At residual oil conditions, most of the oil remained in the form of ganglia extending to several channels. Occasionally, oil was trapped in small entities encompassing a pore and couple of throats, but rarely was it in the shape of droplets residing in the middle of the pore.

Two other observations are noteworthy. (1) When water injection was started for this imbibition test, first the in situ water was produced as seen at the producing lines. This observation was possible since two different colors were used for dying water. (2) It was noted that some in situ water was also trapped in the model; that is, it was not displaced by injected water.

Oil/Water Steady-State Test

Three tests were performed in which white mineral oil (2.5 cP) and brine were concurrently injected. Oil/brine respective injection rates for these tests were: 0.34/0.34, 0.19/0.35, and 0.092/0.16 cm³/hr. The duration of continuous injection for each of these tests was approximately 7, 25, and 90 hours, respectively. Flow behavior was recorded during transient as well as steady-state conditions, both at pore and model scales.

Fluid production in these tests, as seen through the transparent tubing connected to the producing well, was in the form of discontinuous and sometimes nonuniform slugs. However, unlike gas-water steady-state tests, the flow was continuous, as would have been expected for liquid-liquid flow.

In all tests, neither brine nor oil seemed to maintain individual continuous channels from the injection port to the producing port for a noticeable length of time. Rather, the oil transport was seen to be in the form of small slugs, varying in size as they moved from pore to pore, but generally occupying fewer than four to five pores. These slugs coalesced as they came in contact with already existing oil ganglia. As the interfaces were stretched due to the coalescence and viscous forces, the capillary equilibrium was disturbed, resulting in spontaneous detachment of about the same volume of oil from the front. This sequence of coalescence and detachment continued from the injection port to the producing port. Capillarity seemed to play an important role in dictating the location, shape, and size of these slugs. At certain locations, capillary forces were so strong that small oil droplets were continuously formed and jumped to merge with adjacent oil slugs with a higher velocity than the eye could detect. This phenomenon is shown in figure 1. Sometimes, the water advancing through the interfaces and the water imbibed in throats and smaller pores divided the oil ganglia into smaller slugs, which then became mobile.

FIGURE 1. - An example of pore-to-pore oil transport during o/w steady-state flow in heterogeneously etched glass (HEG) micromodel. The sequence of photographs (A) through (F) shows an oil droplet detaching from a pore, jumping to an adjoining pore, and coalescing with oil channel.

- (A) Oil mass labelled X is seen isolated from adjoining channels labelled Y and Z.
- (B) A small oil droplet being detached from channel Y.
- (C) Oil droplet jumping towards oil mass X at an accelerated velocity.
- (D) Oil droplet being coalesced with mass X.
- (E) Mass X momentarily connected to channel Z.
- (F) Mass X isolated again after connection is broke.

The channels filled with brine and channels that contained mostly oil alternated, and quite frequently, both oil and brine shared the same channels. Because of lower oil-brine interfacial tension compared to that of the gas-brine system, the oil-brine interfaces usually had a higher curvature than that in the gas-brine tests.

Oil/Water/Gas Steady-State Test

Three-phase flow was established by simultaneously injecting nitrogen, brine (1% NaCl), and white mineral oil (2.5 cP). The brine and oil were injected at respective constant rates of 0.14 and 0.12 cm³/hr using two syringe pumps, whereas nitrogen was injected at a constant pressure of 6.83 psi using a low-pressure regulator from a nitrogen bottle. The producing end was maintained at a partial vacuum.

This unusual configuration for establishing three-phase flow was adopted by trial-and-error after facing serious difficulties in maintaining three-phase flow over extended periods. The saturation envelope on a ternary diagram, in which all three phases can flow simultaneously, appeared to be extremely small for this HEG model. The major problem was adjusting gas flow; a high gas rate would hinder liquid flow, whereas, at low initial rate, gas flow would eventually cease. Once gas flow had ceased, it would not start flowing again even after applying five times higher injection pressure (up to 30 psi). After allowing 7 hours for equilibration, steady-state was resumed, the model was scanned at 1X, 4X, and 35X magnifications, video images were recorded, and the results were analyzed.

The three-phase flow mechanism was found to be more complex than currently described in the literature.²³⁻²⁴ Three examples are shown in figures 2 through 4. Only the gas phase seemed to have continuous channels, at least some at all times during the flow. Most of the gas channels, however, contained mobile liquid slugs. Along the flow path of these liquid slugs, the continuity of gas channels was made and broken intermittently (fig. 2). Oil did not form continuous channels of its own, rather, it flowed through the gas channels, moving from one pore to another, passing through the throats in the form of a "hopping" motion (fig. 3). The movement of oil in this manner resulted in the transport of some brine as well. Another type of flow was observed in which all three-phase were flowing concurrently in form of emulsions (fig. 4). Some other mechanism of brine flow might have been involved since the injection rate of brine was slightly higher than that of oil, whereas the transport of brine along with oil slugs was much smaller. A microscopic examination at 200X showed some brine to be flowing through the lamellae adhering to the grain surfaces.

2 (A)

2 (B)

2 (C)

2 (D)

2 (E)

2 (F)

FIGURE 2. - "Alternating channel" type of flow observed during oil/water/gas test in HEG model. The sequence of photographs (A) through (F) shows changing fluid distribution even though steady-state conditions were apparently attained. Even though oil and gas were displacing each other alternatively, water distribution was relatively unchanged. These movements were also instantaneous. This was the most common type of mechanism observed in this type of tests.

FIGURE 3. - "Hopping" motion observed during oil/water/gas steady-state flow test in HEG model. The sequence of photographs (A) through (F) shows oil transport from left pore to right pore in the center. These movements were almost instantaneous and could not have been seen without high-speed photography. What is not apparent from these photographs is that this type of movement results in the transport of some water as well.

FIGURE 4. - "Emulsion" type of flow during oil/water/gas steady-state test in HEG model. All three phases are flowing concurrently in form of emulsion. Gas is the internal phase, and brine is the external phase. Oil is mostly contained in plateau borders of adjoining lamellae.

OBSERVATIONS IN CRYOLITE MODEL

Model Description

This micromodel contains grains of cryolite which are chemically consolidated after packing. A prominent feature of this type of micromodel is that the distribution of oil can be seen more clearly. This technique has been described by Childress¹¹ in detail. The pore volume of this model was estimated to be 0.78 cm³.

CO₂ was injected into a clean, dried model for about an hour. Then 50 cm³ of water was injected at a rate of 2.5 cm³/hr into the model to saturate the model fully with water. Oil/water drainage and imbibition tests were then performed.

Gas/Water Unsteady-State Drainage Test

The model was fully saturated with brine at the start of this test. Gas was injected into the model at a rate of 1.2 mL/hr (10 ft/day). The larger-capacity channels were the first to be invaded by gas, which formed fingers of a honeycomb structure. The larger-capacity channels, located mostly at the junction of grains and confining boundaries, overwhelmed the displacement behavior.

When brine production stopped, gas had almost swept the entire model, except for a few pockets left unswept. These unswept pockets were seen to have a much tighter packing than the rest of the model. Brine was also held in small capillary sized channels throughout the model (both in swept and unswept zones), and presumably, also in the form of surfaces films.

No continuous brine flow in channels was seen, except that brine occasionally 'hopped' from one throat to another. Perhaps this small volume of brine transport was through the lamellae fluid hopping.

The production began with both water and gas coming out in the form of alternating slugs about 3 millimeters long. The size of the gas slug gradually increased, whereas the water slug size remained constant. This alternating slug type production in the producing lines may be the consequence of having only one outlet for production, but the microscopic examination revealed a discontinuous flow of brine in the pores, as mentioned above.

Remaining brine was in the form of isolated pockets, in interstices, cervices, and in interstitial layers. No brine was seen in the center of the pores.

The model was rescanned after an overnight interval to observe fluid redistribution, but no changes were apparent.

Gas/Water Unsteady-State Imbibition Test

After the previous test in which brine saturation was reduced to residual, brine was re-injected at the same rate (1.2 mL/hr, 10 ft/day) to observe the imbibition behavior. Brine flow through interstices and consequential displacement of gas was seen; however, displacement of gas by axial (through the center) invasion of water was not seen, which would have resulted from a piston-like displacement. In case of brine displacing gas (favorably mobility ratio), a piston-like displacement is generally expected, at least on a model scale. Our observations do not show a piston-like displacement on a microscopic level.

At residual gas conditions, a significant volume of gas remained in the model. Preferentially, gas remained in the largest channels, generally in the form of ganglia extending to several pores in all three dimensions like a honey-comb structure. However, as in other micromodel tests, exceptions were also present; for example, gas was seen in smaller channels when those channels were attached to a large ganglia.

Gas/Water Steady-State Test

Establishment of gas/water steady-state flow was attempted by using two syringe pumps and experimenting with different injection rates; however, gas flow always ceased before steady-state conditions were attained. The reason for failure to attain steady-state gas/water flow in this apparatus is not clear. It might be due to the limitations on maximum design pressure, the compressibility of gas, or some other unknown operational problem. Finally, the injection scheme had to be changed. Two-phase steady-state flow was established by injecting nitrogen at a constant pressure (3.5 psig) while injecting water at a constant rate (2.7 mL/hr).

At the model scale, water was seen to accumulate in tighter zones. However, because of the peculiar configuration of these zones, it is quite likely that a considerable portion of this water was not flowing. It appears that fluid distribution, even at steady-state conditions, is strongly influenced by macroscale heterogeneities.

On a porescale, water was seen to form channels of its own. These channels were definitely smaller than the gas channels. Unlike gas channels, water channels were not always continuous. The bridge between these discontinuous channels was formed through thick interstitial layers in the channels mostly containing gas. The smooth curvatures of the gas bubbles in the channels suggest that the water on the interstices was thicker than the microlayers, and the flow of water through these interstitial layers was also seen.

Oil/Water Unsteady-State Drainage Test

For this test, the model was fully saturated with brine by injecting 100 cm^3 of water at a rate of $0.34 \text{ cm}^3/\text{hr}$. Oil injection was then started at a rate of $1 \text{ cm}^3/\text{hr}$.

Oil was seen to invade channels first which were larger in size, with a few of the channels reaching as far as the injection well. Fingering was seen through the first 1/2 inch of the front, and the remainder of the front close to the producing well seemed to be quite stable.

It was apparent that the channels invaded by oil were three-dimensional. Even after breakthrough, oil continued to invade more and more channels. Oil invasion through the pores was seen and recorded.

It was seen by changing plane-of-view on the microscope that there was always a layer of water wetting all the surfaces, including those of the grains. Oil was frequently seen to saturate

the pores only partially. This observation was in contrast to the notion that nonwetting phases completely fill the channels except for a microscopic layer of the wetting fluid.

The production behavior was as follows. After breakthrough, oil production started in the form of 1 to 2 millimeter slugs. The size of oil slugs gradually increased as water slugs decreased until the produced volume contained essentially oil only.

Oil/Water Unsteady-State Imbibition Test

For this test, water was injected at a rate of 1 cm³/hr until oil production in the production stream was virtually stopped. Water advanced in the form of a major tongue in the center covering most of the central areas. Otherwise, sweep was excellent within the tongue. This tonguing may perhaps have been due to the variation in pressure gradient caused by the spatial location of the wells in the center of plane perpendicular to the flow. More oil was accumulated on the longitudinal sides (parallel to flow).

It appeared that water was displacing oil interstitially through smaller channels first; and not axially. Displacement behavior as well as fluid distribution and entrapment in the pores was recorded.

Oil/Water Steady-State Test

Oil and water were injected simultaneously through separate injection ports using syringe pumps. The water rate was 1 mL/hr, and the oil rate was 0.37 mL/hr. Displacement behavior was observed after the flow became stable. The production was in the form of uniform slugs, but it appeared that the slug formation was due to the gravity segregation in the producing well.

It appeared that the wetting phase was not always in smaller channels, and in many instances water (the wetting phase) was seen in relatively larger channels, or one could also say that oil was seen in smaller channels. Oil advanced through zones where it found the least overall resistance, and during the invasion in a zone, oil swept the smaller channels as well. Even though the size distribution of channels containing each fluid was influenced by the sweep efficiency, there appeared to be a tendency for water to be in smaller channels, and oil to be in larger channels.

Oil was seen to reside in the pores in the form of rounded surfaces (spheroids) almost filling the pores (except interstitial layers of water). The connection was made between adjacent pores in the form of tongues passing through the throats.

Oil flowed through channels containing mostly oil. However, it appeared that not all the oil saturation was participating in flow because some oil ganglia were discontinuous, and some were extending to the dead end pores and, as such, could not have been participating in the flow process. Water, on the other hand, did not form its own separate channels, rather it occupied all the space left by oil.

Some pockets were unswept by oil. These pockets looked like relatively tighter packings of grains, or were those areas crushed during drilling of the injection port through the glass.

After the steady-state test, a second test was performed to see the influence of injection and production well configuration. In this test, both fluids were injected through the same inlet port such that fluids were premixed before entering the porous media. No difference in behavior was noticed. Why was the fluid production in the form of slugs even after steady-state conditions were attained? To address this question, fluid production was carefully monitored near the producing well under the microscope. No definite answer was found, but a few indirect clues indicated that segregation due to gravity was taking place after fluids were produced from the porous media, and not in situ.

Oil/Water/Gas Steady-State Tests

Two tests were performed in which three-phase steady-state flow was established. In one test, fluids were introduced directly into the porous medium with mixing. In other tests, all three fluids were injected from the same port. Surprisingly, some observations were different in the two cases.

In the first test, fluids were injected directly into the porous medium through three separate wells drilled at the same distance to each other. Gas was injected first at a rate of 5.1 cm³/hr using a syringe pump. When gas injection was initiated, the model contained water and oil resulting from the two-phase steady-state test described above. After gas flow was stabilized, the two liquid phases were introduced one by one. First, water was injected at a rate of 0.51 cm³/hr, then oil, at a rate of 0.25 cm³/hr.

When gas injection began, severe gas channelling was seen. Gas advanced through a few fingers only. Initially, mostly oil was produced, suggesting that the gas had invaded oil channels only. A microscopic examination confirmed this phenomenon. Gas had invaded the oil channels in the oil-swept zones. These channels appeared to be three-dimensional. Later, when all three phases were simultaneously injected and a steady-state condition was attained, gas were

always seen in channels previously containing oil, and there were always layers of oil surrounding gas. The presence of gas, when at residual conditions, reduced the capacity of channels for oil flow. For the same rate of flow, the least resistance was offered by gas and the highest resistance was offered by water.

During three-phase flow, production was not continuous but appeared to stop or slow periodically, then surge and continue for a few moments, and then stop again. Production was taking place in the form of nonuniform slugs; that is, a small slug of brine, then two very small slugs of oil, then a large slug of gas. This behavior was similar to that in the network model. On microscopic examination, fluids were seen to make and break channels quite frequently. This mechanism continued even after flow had stabilized. Thus, the pore-scale flow mechanism can be characterized by the type of breaking and reforming. However, as discussed further, this mechanism can be attributed to this particular configuration of injection wells.

At the conclusion of test 1, the injection of nonwetting phases (oil and gas) was stopped, but water injection was continued until the production consisted of only water and no oil or gas was evident. Water injection was stopped at this point. Water reinjection was started after 2 hours, and the production behavior was carefully observed. All three phases were produced in the form of a sequence of slugs described as follows: oil (a slug of about 1.5 to 2 in. segment in the tubing); water, 1/4-in.; oil, 1-in.; water, 1/4-in.; oil, 1/4-in.; water, 1/4-in.; gas, 2-in. Then alternating gas slugs became gradually smaller, whereas water slugs remained to be 1/8 in. Finally, slugs of oil became gradually larger, whereas the slugs of gas became smaller. Eventually, and suddenly, the production contained 100% brine.

Since the model contained only residual oil and gas when water injection was resumed, only water production was expected. The only apparent explanation of oil and gas production is that the fluids were redistributed during shutdown.

In the second test, all three phases were introduced into a tee connecting to the single injection port. Gas rate was $2.5 \text{ cm}^3/\text{hr}$; oil, $0.57 \text{ cm}^3/\text{hr}$; and water, $0.49 \text{ cm}^3/\text{hr}$. For the first 2 to 3 hours of flow, fluids were seen to redistribute themselves frequently in the form of channels; however, after injecting the fluids overnight, a steady-state condition was attained.

Unlike the previous test (where each fluid was injected through a separate well), the production was stabilized; that is, production was in the form of repeated (signature) small slugs. Sequence was as follows: 1 mm oil, 3 mm brine, 1 mm oil, 6 to 7 mm gas, 1 mm oil, 3 to 4 mm gas, 1 mm oil, and 3 to 4 mm gas. Redistribution was seen in both oil and gas phases in many pores

even though the flow was at a steady-state condition. These movements were localized on a pore scale and appeared as if lamellae were moving at the same location. Such movement was more obvious near the injection port, and very little movement was seen near the producing well. This observation shows that the location and configuration of injection ports have a profound effect on the flow of fluids through micromodels.

OBSERVATIONS IN ROCK-SLAB MODEL

Model Description

These models are composed of an actual rock slab of several millimeter thickness sandwiched between two transparent plates. Gaskets are used to confine the flow to the rock, whereas a coating of clear silicone rubber (room temperature vulcanizer, abbreviated as RTV) is applied to eliminate by-passing through the adjoining rock/plexiglass surfaces. A detailed description of the fabrication technique has been reported previously.¹

CO₂ was injected into clean, dried models (containing a Bentheimer and a Berea rock slab) for several hours. Then 40 cm³ of water was injected at a rate of 0.67 cm³/hr into each model to saturate the models fully with water. Oil/water drainage and imbibition tests were then performed.

Oil/Water Unsteady-State Drainage Test

Oil was injected into the model at a rate of 1.56 cm³/hr (equivalent frontal velocity = 10 ft/day). Oil invasion in the rock was first in the form of a small shock front, in which the saturation of oil was quite high. Later, small fingers of oil were formed. At this stage, the injection was stopped.

When the model was examined after 24 hours, fluid redistribution was clearly seen. The oil saturation at the shock front was reduced, and the oil fingers previously formed advanced and grew in size. Because no fluids were injected, it is surmised that the water from the areas where the saturation was high migrated to the shock zone, reducing oil saturation there. As a consequence, oil moved ahead in areas where its saturation was low.

As the injection of oil was resumed (at the same rate), the frontal behavior was the same -- oil formed fingers first, then a shock front was formed. Oil fingers eventually reached the producing well causing breakthrough.

No axial displacement of brine by oil invading through the channels was evident. When the oil was introduced in a channel, it did not completely (or mostly) displace the brine in a piston-like fashion. The pore-level displacement behavior is instead surmised to be as follows. When oil invaded channels containing brine only, it first formed a thin filament. These filaments then gradually grew in size, and in doing so, expelled brine. In the swept zone, a continuous network of these filaments was seen. However, a couple of hopping motions were also seen in a few pores, which took place so fast that the correct motion could not have been captured.

Fluid redistribution was seen clearly after the system was shut down during the weekend in such a way that water accumulated near the injection and producing wells and oil was accumulated in the central portions.

Oil/Water Imbibition Test

Water was injected at a rate of $0.17 \text{ cm}^3/\text{hr}$ (equivalent frontal velocity = 1 ft/day) into the model containing oil and residual water.

When water saturation was increased to a maximum, resulting in residual oil condition, the model was microscopically examined for oil-entrapment mechanisms. Oil distribution and configuration were significantly influenced by rock/fluid capillarity. Oil was not trapped in the middle of the pores in the form of spherical drops, rather, it was stored in the form of complex entities. There was a tendency for these residual oil masses to conform to the rock surfaces; therefore, the shape was highly influenced by the geometry of the pores encompassing it.

Occasionally, but not often, the oil was seen to adhere to rock surfaces indicating fractional wettability characteristics of the rock. Most of the wetting surfaces, however, were impurities in the matrix, as indicated by their dark colors, whereas the matrix was colorless.

Another interesting observation was the lack of correlation between the size of channels and which fluid it would contain. There was no doubt that the smallest of the channels always contained water (wetting-phase), and the largest of the channels contained oil (non-wetting). But the size distribution of mostly oil- and water-containing channels was mixed for intermediate size channels; that is, oil was not always in the larger channels, and the water was not always in the smaller channels.

Oil/Water/Gas Flow

Gas was introduced in the model containing oil and water after steady-state flow. Gas was seen to invade channels primarily containing oil. However, gas channels became discontinuous shortly after gas injection was terminated because of the fluid redistribution. The liquid phases imbibed in the throats and expelled the gas from there. Gas accumulated in the opening of the pores, and because of the surface tension of oil, formed well-rounded bubbles of very low curvature.

Thus, in typical pores and throats, the gas distribution was as follows: Gas was in the middle in the form of bubbles and other round configurations. A ring of oil was always present around the gas.

Thin-Slab Micromodels for Foam Studies

A feasibility study was performed to evaluate the potential of micromodels containing thin slabs of rocks for studying foam flow. In these tests, the micromodel was initially saturated with brine, which was then displaced by a surfactant solution. Air was then injected, and pore-scale behavior was observed. A typical observation is shown in figure 5. Foam generation in the pores of the rock was clearly seen. Most of the foam was in the form of isolated lamellae (fig. 6), but some foam did exist in the form of bubbles (fig. 7). Foam bubbles had only limited mobility, but most of the bubbles could not pass through the pore throats (fig. 8). These observations show that it is possible for foam to exist in the pores of reservoir rocks, at least in ideal conditions. However, it appears that foam has to be generated in situ (by breaking and reforming), even if prepared foam is injected in the rock. The characteristic reduction in mobility when a foamer is injected with gas is believed to result from permeability reduction in the rock and not to an increase in the apparent viscosity of injected fluids.

FIGURE 5. - Example of foam in a Berea slab (1 in. circular, 3 mm thick). The lighter areas show pores and their contents, whereas the grains appear to be out-of-focus dark shades. Foam can be seen in the form of both lamellae and bubbles in co-existence.

FIGURE 6. - An example of a foam lamellae dividing the pore. The lighter areas show pores and their contents, whereas the grains appear to be out-of-focus dark shades.

FIGURE 7. - An example of foam in form of pore-size bubbles. The lighter areas show pores and their contents, whereas the grains appear to be out-of-focus dark shades.

FIGURE 8. - An example of a dynamic foam finger. The lighter areas show pores and their contents, whereas the grains appear to be out-of-focus dark shades.

CONCLUDING REMARKS

Several observations presented in this report were made during oil, water, and gas flows in various combinations and conditions. The aims of these experiments were to improve the existing technologies of micromodel fabrication, and using these improved models, to perform basic single and multiphase flow tests under comparable conditions to compare behaviors.

The improved models strictly showed pore-level behavior, with no by-passing through the confining boundaries -- a problem encountered in packed micromodels which distort the pore-level behavior.

Flow mechanisms were visualized through these improved models as described in this report. Many of the observations were in agreement with our understanding of fluid flow through porous media as obtained through literature reviews. In several instances, a direct and refined observation is presented here for the first time.

No other study to our knowledge has offered direct observations of fluid distribution and movement through the pores of consolidated rocks. Rock-slab models offer geometric similarity

on a microscopic scale, and as such, the observations of the work are slightly more realistic than those of simplified models. As with other micromodels, however, the effect of neglecting scaling criteria and the influence of enclosing surfaces (of different wettability) cannot be anticipated.

This comparison of results from three different micromodels under similar operating conditions has shown that behaviors are not always similar. The obvious reasons are mentioned below. In network models, 1) the pore-to-throat diameter ratio and 2) the number of throats connecting a pore are relatively small, 3) the diameter of channels is relatively large, and 4) the surfaces have different wettability as compared to that of rock-slab models. Even though not confirmed from this study, it is suspected that the wettabilities of network models are generally weaker than reservoir rocks. Thus, the influence of rock capillarity and tortuosity are not properly simulated. Similarly, the heterogeneities in wettability and pore/throat geometry found in the rock are not duplicated in network models. Besides, the flow in network models remains to be strictly two-dimensional, as opposed to three-dimensional flow (microscopically) in a rock-slab model; hence, the role of gravity segregation cannot be observed.

When compared to network models, the cryolite model is much closer to rock-slab models in resembling several of its properties, such as capillarity, tortuosity, and three-dimensionality. It is lacking, however, in representing the heterogeneous nature of rock's wetting characteristics and pore/throat geometry. Nonetheless, cryolite models have been shown to be one of the best alternatives available to simulate natural rocks.

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