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THE FOAM-DRIVE PROCESS FOR INCREASING THE RECOVERY OF OIL

By A. N. Fried

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

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THE FOAM-DRIVE PROCESS FOR INCREASING THE RECOVERY OF OIL[1]

by

A. N. Fried[2]

INTRODUCTION AND SUMMARY

With the growing importance of fluid injection in recent years, the petroleum industry has been investigating and field-testing a variety of new methods designed to modify the physical properties of reservoir oil to improve the efficiency of gas and water injection. These procedures include condensing-gas drive, LPG (liquefied petroleum gas) injection, alcohol-slug process, high-pressure-gas displacement, detergent-solution flooding, and in situ combustion (30, 37).[3]

A new and different method to increase the effectiveness of gas and water injection has been tested by the Bureau of Mines. Consideration of both fundamental and practical factors that operate to limit the oil recovery attainable by conventional oil-displacement mechanisms led to the concept of a displacement mechanism called the foam-drive method. This report describes the experimental study that tested this concept in the laboratory.

The residual oil of a reservoir depleted by conventional displacement processes is retained primarily because of heterogeneity in rock permeability, pore geometry, capillary or surface properties of the solid-fluid contacts, and the relative viscosity characteristics of the fluid phases. In some parts of the reservoir a large part of the oil has been displaced, leaving globules or small discrete masses of oil. In other parts of the reservoir, oil has been bypassed and remains in isolated islands in the sand body. It thus may be reasoned that to displace the residual oil, any subsequent recovery process must provide a means by which (1) expulsive energy may be brought to unflushed regions of the reservoir, (2) surface or capillary forces which cause retention of oil may be counteracted, (3) viscosity effects which permit extremely high rates of flow of the displacing medium relative to the oil flow rates may be favorably modified, and (4) the number of flow paths available exclusively to the movement of the displacing phase may be decreased. Analysis of

[1] Work on manuscript completed December 1960.
[2] Petroleum research engineer, San Francisco Petroleum Research Laboratory, Bureau of Mines, San Francisco, Calif.
[3] Underlined numbers in parentheses refer to items in the bibliography at the end of this report. Page references refer to pages in the items and not to pages in this report.

the known properties of foams, plus other factors deduced from fundamental properties of colloidal dispersed systems, seemed to indicate that injection of foam might fulfill the foregoing requirements and increase oil recovery.

In this process, foam of required stability is generated by dispersing a suitable gas (air, nitrogen, methane, and so forth) in dilute aqueous solutions of surface-active agents, and the foam is injected into the reservoir. The foam forms a zone or bank which is pushed through the reservoir by injected gas. A sharp pressure drop across the foam bank combined with the unique action of mobile and trapped foam bubbles causes displacement of oil and the formation of an oil bank, which is moved effectively through the reservoir. The presence of foam in the sand markedly lowers the effective gas permeability (k_g) and to a lesser degree oil permeability (k_o). Thus, despite decreased oil saturation, the k_g/k_o ratio is reduced, which is an aid to recovery.

Laboratory-scale oil-displacement experiments showed that the foam-injection technique can be used to recover a large proportion of the oil remaining in unconsolidated sands that have been subjected to conventional gas drives and water or surfactant-solution flooding. In tests utilizing 78- to 850-centipoise oils, oil saturations were reduced by 44 to 70 percent of the oil that was left in the sand by conventional displacement methods. Best results were obtained with high viscosity oils. Not only were final residual oil saturations reduced to as low as 13.8 percent of the sand pore volume, but average produced gas-oil ratios during oil depletion by foam-drive ranged between the equivalent of 5 to 5.6 M c.f. per barrel of oil. These performances, in sands in which gas-oil ratios just prior to foam injection exceeded the equivalent of 10 M c.f. per barrel at the end of conventional gas drives, indicate the effectiveness of foam in altering flow distribution and fluid conductivity in the reservoir.

This report discusses the mechanism of the process and presents results of laboratory tests of the foam-drive method.

ACKNOWLEDGMENTS

For their critical reviews and helpful comments, the author is greatly indebted to Dr. Irving Fatt, professor of petroleum engineering, University of California, Berkeley, Calif.; Ionel I. Gardescu, manager, Oil and Gas Division, H. Zinder and Associates, Inc., Houston, Tex.; and George J. Heuer, Jr., section supervisor, Production and Research Division, Continental Oil Co., Ponca City, Okla.

DISCUSSION OF THE FOAM-DRIVE MECHANISM[4]

The possibility of using foam driven by injected gas to move oil left immobile by previous displacement processes is based on the premise that injecting a suitable foam into the pore system of a reservoir introduces a large number of tenacious and resilient interfaces which exert a pistonlike

[4] A more detailed discussion of the theoretical aspects of the foam-drive method is presented in appendix I.

force on discontinuous oil masses lodged in the interstices. The multiplicity of mobile interfaces of various sizes and curvatures greatly increases the probability that the force or combination of forces required to move most of the static oil masses will be developed. Simultaneously, the unique action of the dispersed phase alters flow patterns and fluid distribution thereby changing the permeability distribution so that the driving medium invades previously bypassed portions of the sands.

Foam injected into the sand surrounding a well bore first disperses through the largest pore channels, presumably those which have been flushed of their oil content. With movement of foam into larger voids and channels, the resistance to flow increases rapidly owing to the high effective viscosity of the foam and to the blocking tendencies of the constrictions along the flow paths. As flow resistance builds up and injection pressure is increased, smaller bubbles are forced into the smaller channels thereby causing a foam bank to be developed. Owing to greater resistance to flow at the injection well relative to resistance to flow in the downstream region of the reservoir, the pressure in the latter region is reduced. Thus, in effect, the pressure gradient across the foam front is increased. With establishment of a mobile foam front, continuous flow paths that had previously carried the greatest part of the total flow of the prior displacing medium become blocked or restricted resulting in (1) diversion of flow to small unflushed flow channels, (2) migration of a medium exhibiting high effective viscosity, and (3) presence of a high-pressure gradient at the invading front. Scavenging of residual oil by foam creates an oil bank or zone of high oil saturation ahead of the foam front.

Foams exhibit markedly greater viscosities than the separate viscosities of the gaseous and liquid phases of which they are constituted. The increased viscosity ratio between displacing and displaced phases favors formation of an oil bank and greater displacement and sweep efficiency.

Since the surface-active agents occur as adsorbed molecules in the gas-liquid interfaces forming foam bubble walls, the tendency to be adsorbed by rock-mineral surfaces is more strongly opposed than in surfactant-solution flooding. In oil-wet or partially oil-wet formations the detergent and wetting effects of surface-active agents used to generate foams promote the displacement of oil from rock surfaces.

The presence of a discontinuous gas phase formed by foam increases the gas saturation of the sands without creating high gas-oil relative permeability ratios. Thus, to some extent, foam tends to produce the effect of a trapped gas.

Presumably, for each porous system there is an optimum thickness of foam bank. At present, neither a fundamental nor empirical method is known for predicting optimum foam bank dimension. After a mobile foam bank of approximately optimum thickness has been established and further injection of foam is terminated, the permeability to injected gas must derive from the network of small communicating capillaries which foam has not entered and from the propulsion of foam in the foam bank. Because the finer capillaries most likely contain wetting liquid (water) and perhaps some oil, it is apparent that the gas can enter small capillaries only if the required displacement pressure is reached. As gas is injected and forces liquid and foam ahead of it, the oil displacement mechanism previously described continues to develop the oil bank at the upstream front.

Factors that tend to dissipate or destroy the foam bank are: (1) The radial outward movement reduces its thickness, (2) the coalescence of larger bubbles and the diffusion of gas from the smaller to the larger bubbles reduce the number of bubbles and hence the number of gas-liquid interfaces, and (3) adsorption of the surface-active substances from the foam liquid to the solid surfaces, or diffusion into the interstitial brines, depletes the foam-forming agent required to sustain the bubble films.

Conversely, movement of foam may result in its redivision into smaller bubbles as it passes through the tortuous paths and constrictions. As the foam and its associated liquid move to regions of lower reservoir pressure, expansion of small bubbles and formation of new bubbles as gas comes out of solution in the liquid, tend to counteract the attrition of the foam bank. Moreover, liquids containing surface-active foam chemicals tend to be pulled by capillarity into constrictions. As gas passes through them, new bubbles are formed. In short, two simultaneous processes occur--one tending to dissipate or destroy the foam, the other acting to renew or regenerate the foam in the formation. The latter action not only aids persistence of the foam bank as it moves toward the producing well but also acts to renew foam in channels in which gas might tend to break through.

As the foam bank moves radially outward from the point of injection it must eventually become so thinly dispersed as to lose those properties beneficial to oil displacement. The foam bank may be augmented by injecting slugs of foam liquid from time to time during the gas-injection phase of the drive. The liquid, owing to the relatively high water permeability of the sand, overtakes and supplements the foam bank by in-situ generation of foam.

Without fundamental relationships that describe the time rate of flow of a heterogeneous dispersed phase (foam) in a porous system, it is not possible to determine quantitatively the effect of foam on areal sweep efficiency. High sweep efficiency has been correlated with low mobility ratios. The presence of foam certainly has the same effect as a decrease in mobility of gas in the invaded regions of the sand but does not alter the mobility of oil in unswept portions ahead of the foam bank. The effect is an apparent decrease in mobility ratio. On this basis it may be surmised that fluids in unswept portions of the unit patterns, formed by injection and producing wells, move downstream under the influence of existing pressure gradients while flow of injected gas through previously flushed areas is restrained by the foam bank.

In a field operation it is apparent that the foam zone must be limited to a thickness that will permit its movement under imposed pressures of a practicable magnitude. Operating pressures will be determined by such factors as depth of pay, reservoir pressure, sand permeability, viscosity of the oil, characteristics of the foam, and other fundamental and practical considerations.

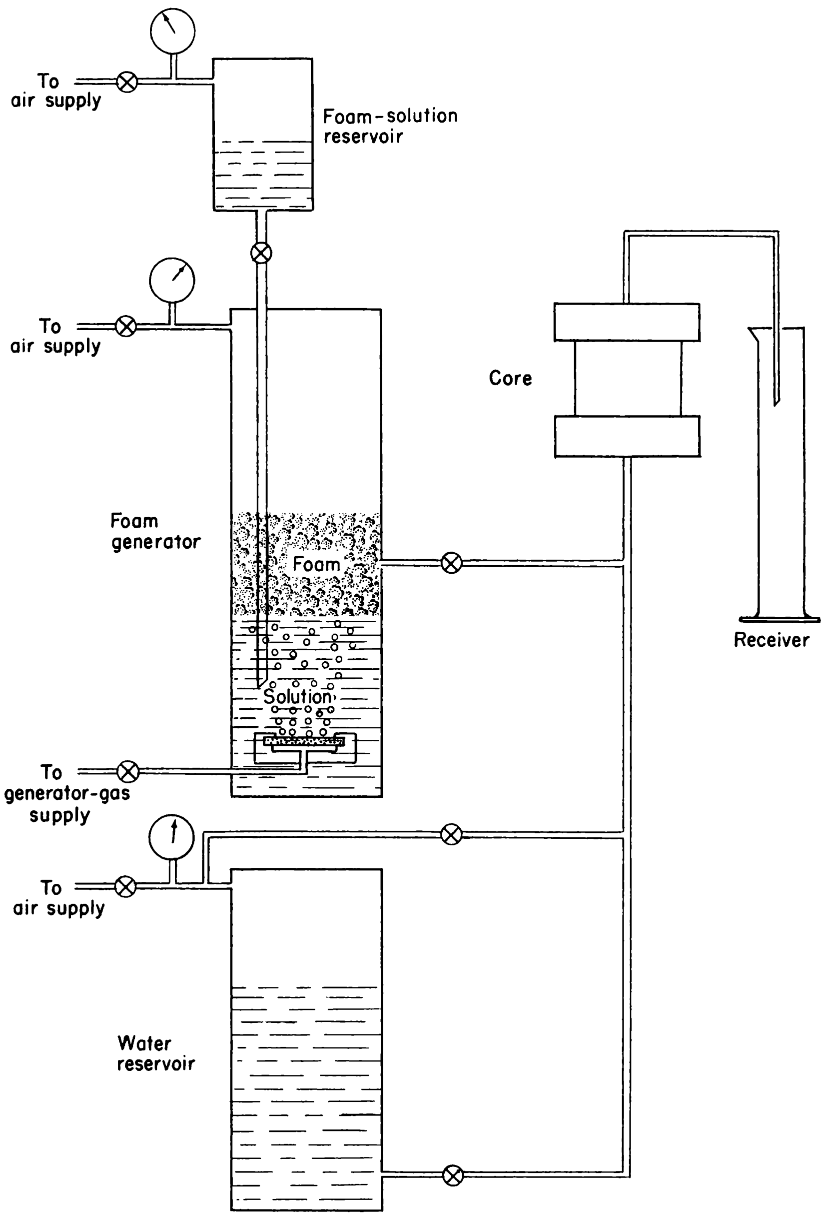

FIGURE 1. - Foam-Injection Apparatus for Preliminary Tests.

EXPERIMENTAL PROCEDURE AND RESULTS

Preliminary Oil-Displacement Experiments

Before large-scale laboratory tests of the foam-drive process were started, a series of exploratory foam-injection experiments was run to gain some experience with experimental techniques and apparatus, and to determine if foam would pass intact through a porous medium and displace oil.

An Aloxite[5] core 5.16 cm. in diameter and 4.85 cm. long was mounted in a transparent thermoplastic. The average air permeability of the core was 30+ darcys; the effective porosity, 36.8 percent. After the core was saturated with distilled water, it was placed in a vertical position to permit water to drain by gravity. It was then connected to the foam generator shown in figure 1. Foam was generated by bubbling nitrogen through an Alundum diffuser at the bottom of a column containing a 2-1/2-percent[6] aqueous solution of Miranol HM Concentrate.[7]

Foam formed on the surface of the liquid was forced into the core at desired flow rates by regulating the pressure in the space above the column.

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[5]Reference to specific brand names is made to facilitate understanding and does not imply endorsement of such brands by the Bureau of Mines.

[6]Concentrations of surface-active chemicals are given as weight-percent of active material in the solutions.

[7]See appendix II for further identification of surfactants mentioned by proprietary name in this report.

As foam entered the core, water, followed by a small amount of foam liquid and then foam were produced. The movement of the foam in pores adjacent to the transparent plastic sheath was observed through a magnifying glass.

The next displacement test was conducted to determine if foam would remove oil not recoverable by gas or water injection. After it had been flushed and dried, the Aloxite core was again completely saturated with water and then flooded with a 350-centipoise lubricating oil until water no longer appeared in the effluent stream. The volume of water displaced was 76.4 percent of the pore space. A gas drive, aided by gravity drainage, displaced 68 percent of the oil in place and left a residual oil saturation of 24.3 percent of the pore volume. Subsequent attempts to displace additional oil by water injection and by alternate water and gas injection, failed to reduce the residual oil by a measurable amount.

Foam generated from a 1.5-percent solution of Miranol HM Concentrate was then injected into the core. First, gas was displaced, then water, and then oil. After considerable clean oil was displaced the foam broke through. The color of the initially produced foam showed the foam was heavily loaded with oil. As flow continued, the foam became progressively lighter until it was as white as the inflowing foam. At this juncture, water injection was substituted for foam injection and additional oil production was obtained. A second foam drive again reduced residual oil saturation. The results of the experiment are summarized graphically in figure 2(a). Significantly, the ratio of produced water (including foam solution) to recovered oil was only 3:1 in the first foam drive.

A second oil-displacement test was conducted to determine if the foam was more effective when injected after a gas drive or after a water drive. Another important objective was to ascertain if, in the previous run, the "third crop" of oil produced by foam injection derived primarily from the detergent and wetting properties of the surface-active chemicals in the foam or from the unique physical properties of the dispersed driving medium. After establishing the primary water and oil saturations in the manner described previously, the initial waterflood was followed by gravity drainage until liquid no longer was produced. A second flood, using foam solution as the driving medium, produced no measurable quantity of oil. In contrast, the ensuing foam drive did reduce the residual oil saturation, as shown in figure 2(b), and indicated quite clearly that the additional yield of oil was primarily the result of intrinsic foam properties rather than the physicochemical action of the surfactant alone. Since the viscosity of the foam liquid was only 1.13 centipoises and the oil viscosity was 350 centipoises, it is unlikely that surfactant-liquid viscosity had any effect on the yield of oil. The run was completed with a final water drive which removed only 1 percent more oil.

Although results of these preliminary tests were encouraging, the extremely high permeability of the porous specimen may have been too favorable to displacement of oil by foam. Moreover, the average pore size of the Aloxite core was considerably greater than that in most naturally occurring oil sands. Therefore, an Alundum core which had an air permeability of

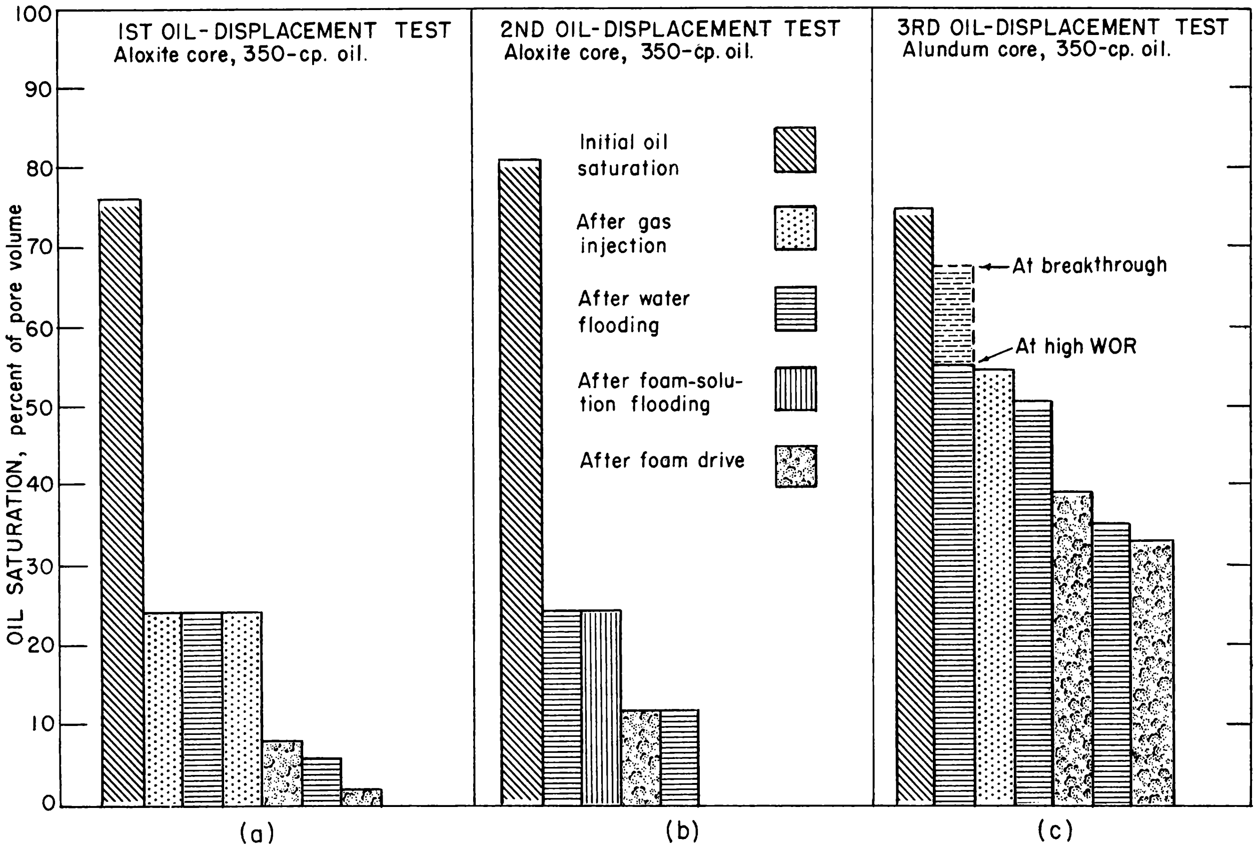

FIGURE 2. - Graphical Summary of Results of Preliminary Oil-Displacement Tests.

350 md. was used in the third oil-displacement experiment. The specimen, 2-1/2 cm. in diameter and 12-1/2 cm. in length, was encased in Lucite. The core was saturated with water and then flooded with the same oil used in the previous tests. The water-wet, semipermeable diaphragm, which had been placed at the outlet face of the core to minimize end effect during oil flooding, was removed. The core was subjected to a waterflood, a gas drive, and a second waterflood, which was terminated when the water-oil ratio became excessively high.

The initial waterflood reduced oil saturation from 75.0 to 54.85 percent of the pore volume, as shown in figure 2 (c). Less than 1 percent additional oil was removed by the gas drive. The second waterflood was terminated with a residual oil saturation of 50.8 percent. Foam, generated from a 2-percent solution of Miranol HM, was injected continuously during the first foam drive and produced slightly more than 23 percent of the residual oil, leaving 39 percent oil saturation in the core. A subsequent waterflood removed almost 10 percent of the remaining oil and reduced the oil saturation to 35.2 percent of the pore volume. In a second foam drive, using a less stable foam generated from a 0.24-percent solution of Drench EP-3, only a small yield of

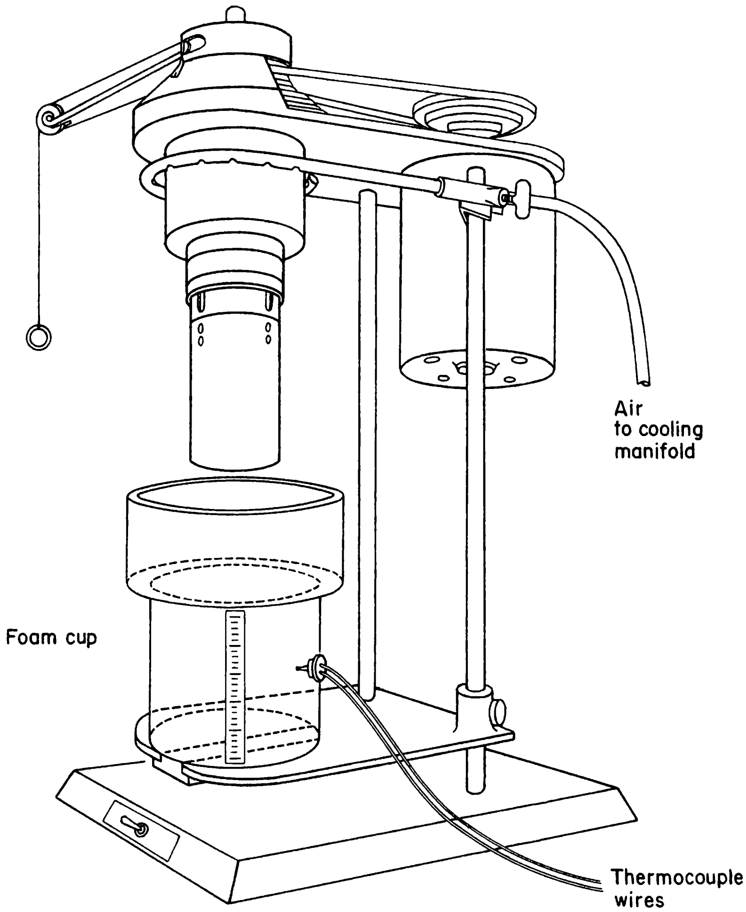

FIGURE 3. - Apparatus for Measuring Viscosities of Bulk Foams.

oil was obtained and at termination of the test, residual oil was 33.2 percent of the pore volume. Thus, the foam drives and intervening water drive recovered almost 35 percent of the oil that remained in the core after conventional water and gas drives.

Study of Foam Properties

To determine if the greater oil-displacing capability of foams resulted from the higher effective viscosity of the dispersed medium, a study was undertaken to develop a rapid method for measuring viscosities of foams. The objective was to correlate, if possible, oil recovery and foam viscosity.

Figure 3 shows a Fann V-G Meter, Model 31,[8] modified to permit use of a specially designed foam container graduated to indicate total foam volume and volume of drained liquid. By means of a thermocouple projecting into the foam through the wall of the container the tendency for the temperature to increase during prolonged testing can be detected. By regulating the air flow through a cooling collar around the viscosimeter shaft, the temperature of the foam can be controlled within ± 2° F. The variable-speed feature of the instrument permits measurement of viscosities at five different rates of shear.

The experimental procedure was as follows: A measured volume of surfactant solution was placed in the viscosimeter cup. A single-rotor Hamilton Beach mixer was used for beating the foam. Foam of desired initial expansion factor was generated by beating air into the solution until the required foam level was reached. The cup was immediately placed in position on the viscosimeter and a series of reading of torque and volume of liquid drainage versus time was recorded. This procedure was repeated with foams generated from various surfactant solutions of different concentrations. Each foam also was tested at several rates of shear. Textural differences between newly generated foams could be only nominally controlled by visual inspection during beating.

[8]Manufactured by Geophysical Machine Works, Houston, Tex.

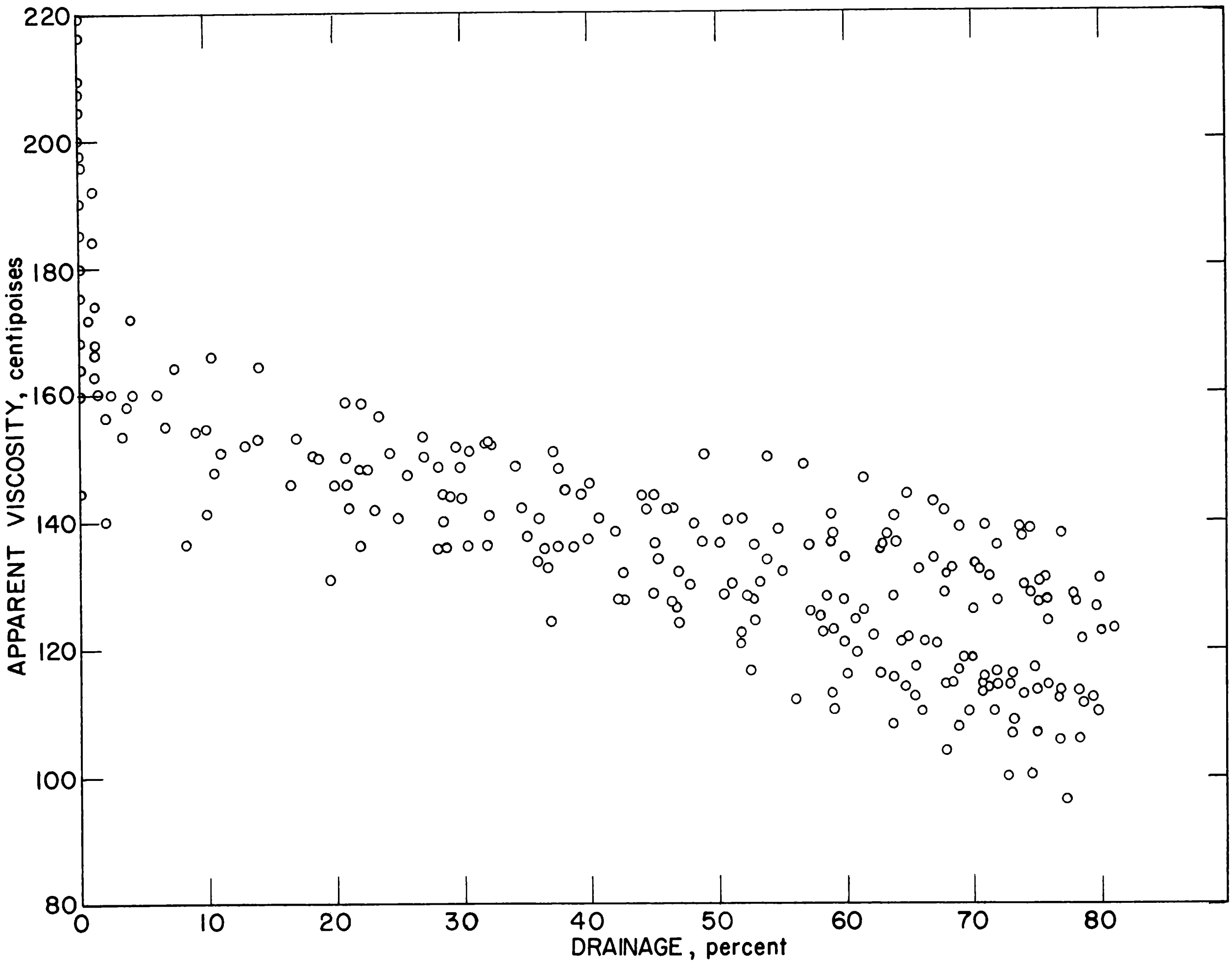

FIGURE 4. - Composite Scatter Diagram of Results of Bulk-Foam Viscosity Tests.

The study of viscous properties of bulk foam revealed a number of pertinent factors. The first of these was that the apparent viscosities of most foams fell within a relatively narrow range. Varying the concentrations of surfactants in the foam solution had surprisingly little effect on viscosity except at the lowest concentrations tested, generally when surfactant concentrations were below the critical micelle concentration. Moreover, most foams exhibited closely similar trends of decreasing viscosity with increasing drainage. In several instances, however, at very low surfactant concentrations where stability was markedly affected, the reverse trend was noted.

Figure 4 is a composite scatter diagram showing the relatively narrow range of viscosities exhibited by foams generated from various concentrations of the different surfactants tested. All tests represented by the data plotted in figure 4 were run at a viscosimeter-rotor speed of 75 r.p.m. Figure 5 shows the influence of viscosimeter-rotor speed (shear rate) on apparent viscosity of foams generated from solutions of various concentrations of Product BCO.

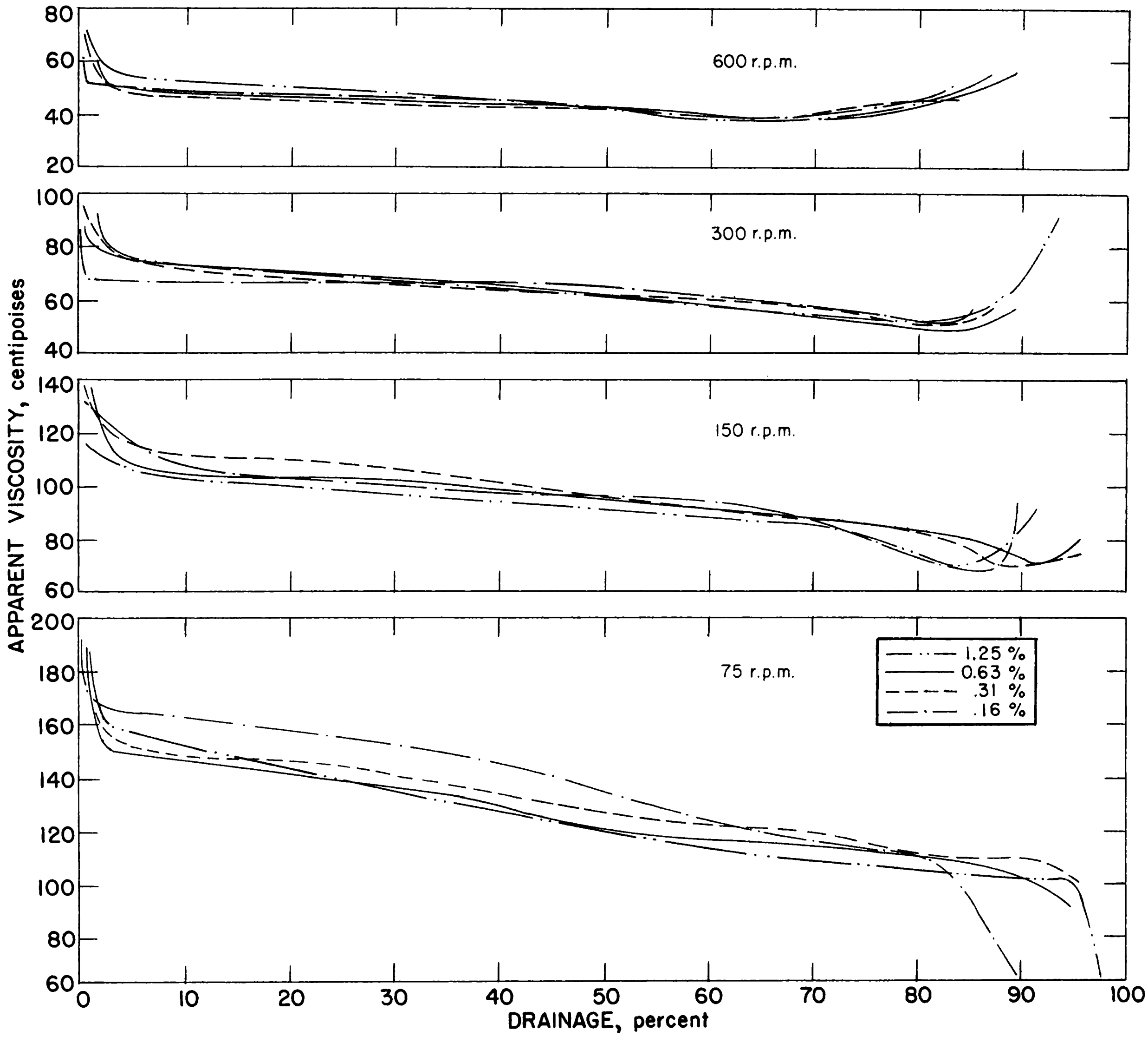

FIGURE 5. - Effect of Shear Rate and Foaming-Agent (Duponol RA) Concentration on Bulk-Foam Viscosity.

The bulk-foam tests served to show that the viscous properties of foams may not be varied widely by either manipulation of surfactant concentration or by selection of surfactant. Foam texture combined with expansion factor had considerable influence on the viscous properties of freshly generated foams but the trends were generally convergent as drainage progressed. In the experimental method employed, the latter effects were transient and could not be measured reliably.

The question arose as to the applicability of the measurements of bulk-foam viscosities to systems in which foam-bubble diameters approach flow-channel diameters. A method was required which would permit apparent-viscosity measurements under steady-state conditions in which the values

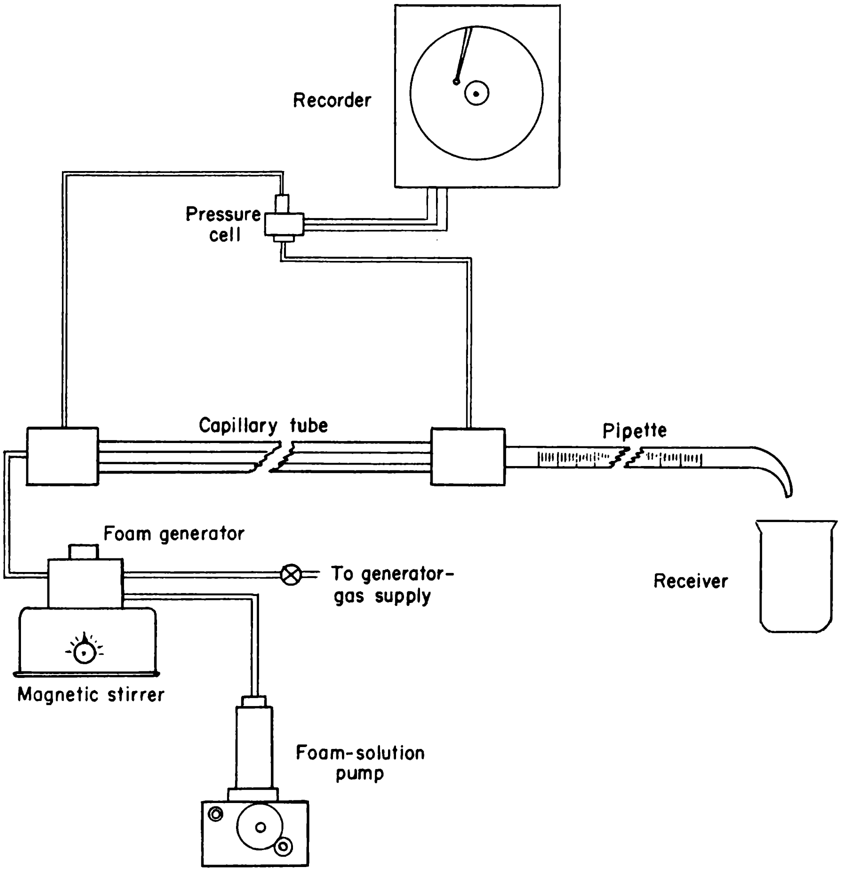

FIGURE 6. - Apparatus for Measuring Viscosities of Foams Flowing in Capillary-Size Channels.

of the parameters could be fixed at desired levels. To accomplish these objectives, an entirely different type of viscosimeter was assembled.

Figure 6 is a schematic diagram of the capillary viscosimeter used in the second study of foam properties. The surfactant solution of desired concentration is fed into the foam generator by the constant-rate pump. Simultaneously, the gas (air, nitrogen, CO_2) also is metered into the generator where a magnetically-driven rotor beats the two streams into a foam. From the generator the foam flows through the capillary tube and into the pipette. The pressure drop across the capillary tube is measured by the differential-pressure gage and is continuously plotted on the recorder. Foam flow is measured either in the graduated pipette at the outflow end of the viscosimeter tube or by the time of travel of foam bubbles along a calibrated length of the capillary tube. By regulating gas flow relative to liquid flow, the desired expansion factor is obtained. Variation in volume rate of foam flow at fixed values of expansion factor may be achieved by changing both liquid and gas rate in proper proportion. A limited degree of flexibility in regulating the foam texture is provided by the speed control of the magnetic stirrer. The effect of capillary diameter relative to average bubble size was determined by conducting a series of viscosity measurements in capillary tubes of various diameters. When the viscosimeter was tested against National Bureau of Standards standard viscosity samples, the flow behavior was found to be exactly in accordance with Poiseuille's law, and therefore, apparent viscosities could be calculated directly from the measured quantities.

The new series of tests showed that the viscosity of a foam flowing in capillary tubes varies almost directly as the diameter of the flow channel. Presumably, for a given size of capillary, flow resistance should increase as bubble size decreases in a foam of given expansion factor. This was qualitatively verified by the study but not quantitatively correlated. Owing to

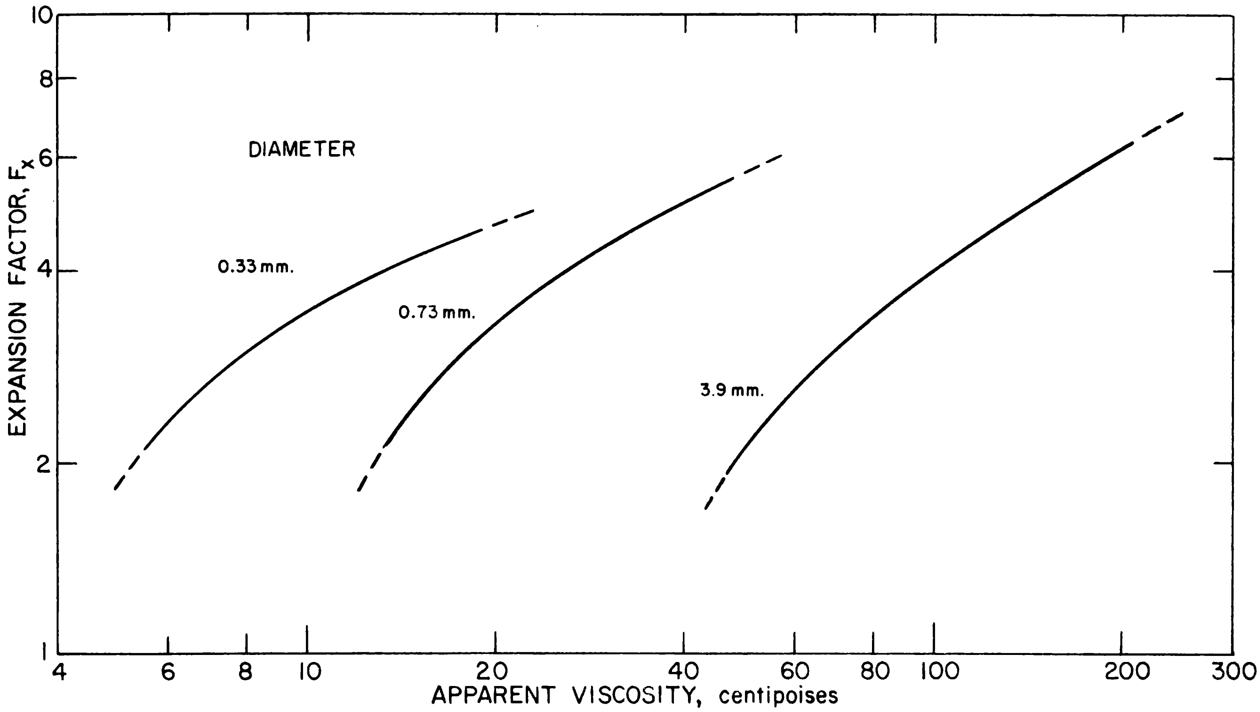

FIGURE 7. - Effect of Expansion Factor and Capillary Size on Foam Viscosity.

the limited range of mixer speeds over which the magnetic stirring device operated, large differences in foam texture could not be obtained. Figure 7 shows correlations between expansion factor and apparent viscosity at constant linear flow rate in capillaries of three different diameters. Figure 8 is a smoothed-data plot showing the trend of apparent viscosity with linear flow rates at fixed expansions. To obtain the correlation, the apparent absolute viscosity, μ, was multiplied by the expansion factor F_x which, in effect, is the reciprocal of foam density relative to liquid density. Thus, μF_x is a kinematic-viscosity function. As previously indicated, the viscosity of a given foam is proportional to the radius of the channel in which the foam is moving. By normalizing the viscosity function with respect to radius, the group $\frac{\mu F_x}{r}$ permitted correlation of data from tests utilizing three different capillary sizes.

The results of the brief study of foam properties indicated that surfactant foams exhibit viscosities considerably higher than those of the aqueous solutions from which they are generated. Although bulk foams may demonstrate apparent viscosities over 100 times greater than the aqueous liquid, the viscosities of the same foams in capillary systems may only be from 5 to 10 times greater than the foam-liquid viscosity. Moreover, there is a limited range over which viscosities may be varied solely by choice of foam-forming chemical or concentration used. Despite these limitations, injection of foams may have the same effect on oil recovery as would a 5- to 10-fold increase in the viscosity of a flooding water. The author (15) showed that in tests using a 300-md. core, a reduction in the ratio of oil viscosity to

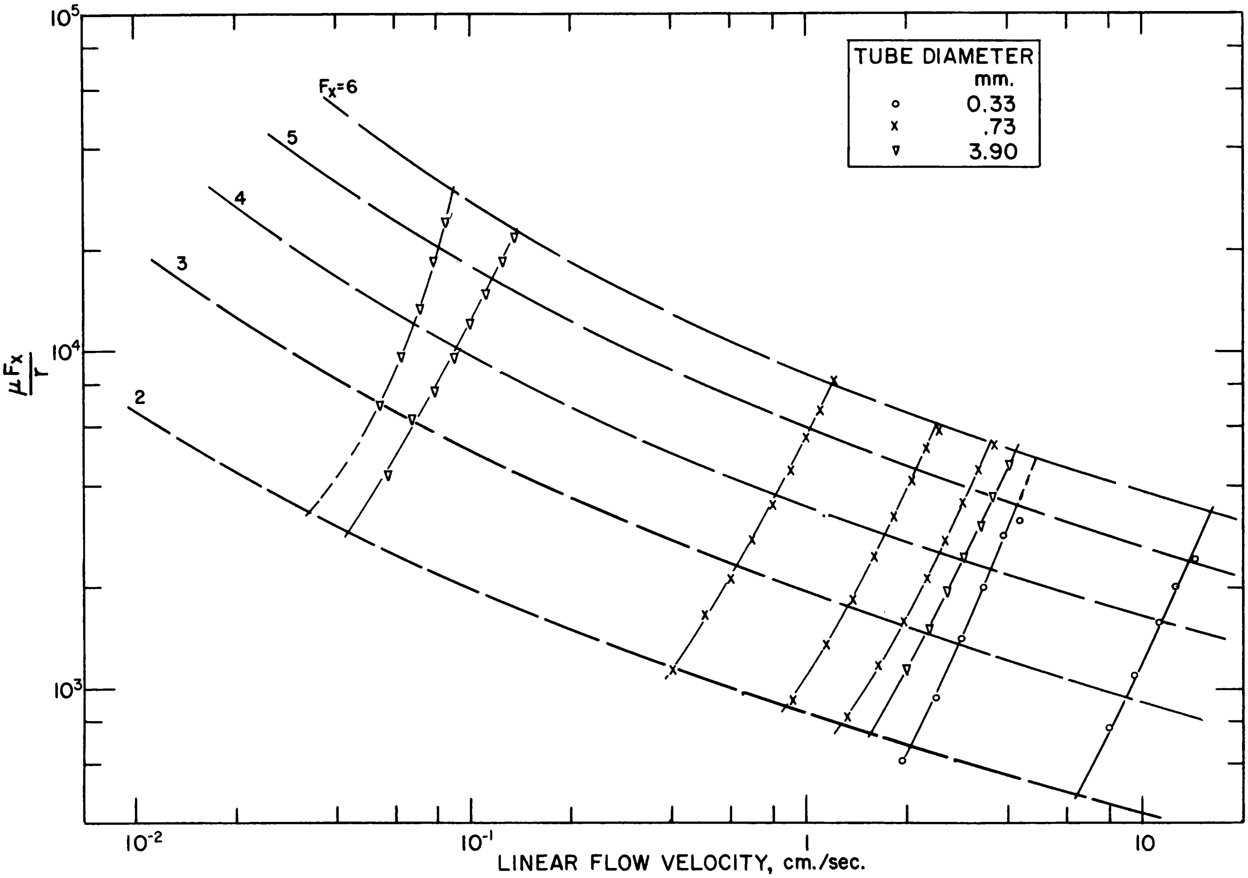

FIGURE 8. - Effect of Linear Flow Rate at Fixed Expansion Factor on Foam Viscosity.

displacing-phase viscosity, $\frac{\mu_o}{\mu_d}$, from 1,000 to 100 or from 100 to 10, lowered residual oil saturation (at a water-to-oil ratio of 20) by 12 to 15 percent of the pore volume. Felsenthal and Uster (14), working with a 420-md. sand, found that a ten-fold reduction in viscosity ratio resulted in an increase in oil recovery equal to 6 percent of the sand pore volume. In the present study it was desired to determine what effect varying the ratio of oil viscosity to foam viscosity has on oil recovery. Owing to the narrow ranges over which foam viscosities may be varied, the desired ratios, $\frac{\mu_o}{\mu_d}$, could be obtained most readily by varying the oil viscosity.

Long Sand Column Oil-Displacement Tests

Test 3-156

In preparation for tests utilizing long sand columns, the initial experiment was conducted on a prototype unconsolidated-sand column 5 cm. in diameter and 18.4 cm. long in an acrylic plastic tube. The sand column consisted of an almost pure silica sand ranging in grain sizes from 28- to 200-mesh. By means of a hydraulic press a load of 1,000 p.s.i. was used to pack the sand to maximum density in the column. The resulting sand column had a dry air permeability of 1.9 darcys and an effective porosity of 26.2 percent.

The sand was first completely saturated with distilled water, then flooded with an oil of 850-centipoise viscosity until a maximum oil saturation of 91.4 percent of the pore volume was attained. Displacement of the oil was accomplished first by gas (air) injection, then by water injection to water-oil ratios greater than 20, followed then by intermittent gas and water drives until virtually no additional oil was produced. With an oil saturation reduced considerably by conventional water and gas drives, foam was injected into the sand. The same foam-generating apparatus used in earlier foam-injection tests (see fig. 1) was used in this procedure. The initial foam was generated from a 0.2 percent solution of Duponol WAQ with 0.02 percent concentration of Sorbit AC. When it became apparent that only a small amount of oil was being displaced, a 1-percent solution of Miranol HM Concentrate was substituted in the generator. Foam was injected continuously at flow rates from 2.4 to 6 cc./min. under injection pressures ranging from 4 to 21 inches of mercury (in Hg) until foam appeared at the outflow face of the sand. At this time the foam injection was supplanted by water-flooding until the water-oil ratio was 100. A third foam drive of short duration completed the test.

In figure 9 a summary of the test results indicates that the foam drive succeeded in reducing the residual oil saturation by 32.7 percent of that attained by conventional gas and water drives. That the process was not highly efficient is reflected by a yield of only 0.05 volume of oil per volume of injected foam solution (as foam) and water.

Test 7-956

A plastic tube 100 cm. long, patterned after the prototype used in the previous experiment, was fabricated and packed with a sand mixture which contained a slightly larger proportion of the smaller size fractions than the previous blend. The air permeability of the sand column was 1.34 darcys and the effective porosity was 25.7 percent. Using the procedure described previously, the sand was first saturated with water, then flooded with an oil having a viscosity of 154 centipoises. Primary oil displacement was effected by waterflooding the sand until the water-oil ratio was 16. The sand was again oil flooded to within 0.6 percent (pore volume) of the original oil saturation. Foam, generated from a solution containing 0.25 percent Triton AS-30, 0.25 percent Nacconal NR, and 0.1 percent Hyonic FA-75, was then injected at pressures ranging from 9 to 18 in. Hg. Injection rates averaged just under 1 cc./min. Surfactant liquid in the foam comprised approximately 3 percent of the foam volume.

The flow patterns, revealed by color gradations visible through the plastic tube wall, showed that the initially injected foam advanced along the wall at the top of the sand column. Less than 2 percent of a pore volume of oil was displaced. In spite of this early nonuniform distribution of flow,

Unconsolidated sand column, 5 cm. diam., 18.4 cm. long.
Air permeability, 1.9⁻ darcys; porosity, 26.2%.
Oil viscosity, 850 cp.; aqueous phase, distilled H_2O;
gas phase, air.
Foam solution: I, Duponol WAQ, 0.2%; Sorbit AC, 0.02%.
II, Miranol HM, 1.0%.

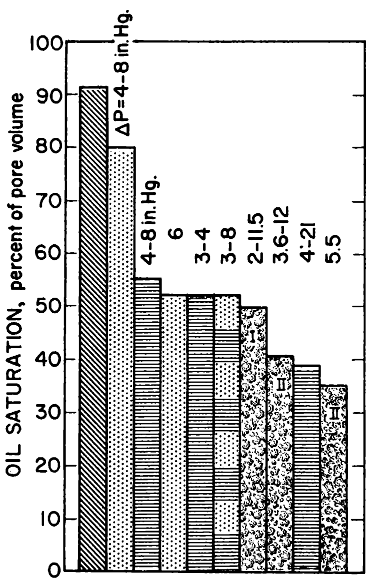

FIGURE 9. - Graphical Summary of Results of Oil-Displacement Test 3-156.

Unconsolidated sand column, 5 cm. diam., 100 cm. long.
Air permeability, 1.34⁻ darcys; porosity, 25.7%.
Oil viscosity, 154 cp.; aqueous phase distilled H_2O;
gas phase, air.
Foam solution, Triton AS-30, 0.25%; Nacconal NR, 0.25%;
Hyonic FA-75, 0.1%.

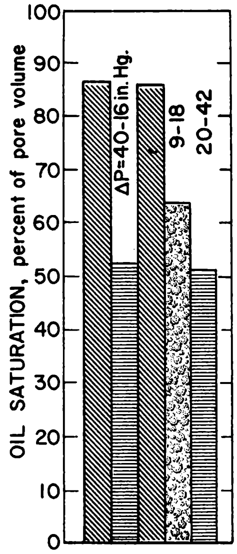

FIGURE 10. - Graphical Summary of Results of Oil-Displacement Test 7-956.

Unconsolidated sand column, 5 cm. diam., 100 cm. long.
Air permeability, 1.3⁺ darcys; porosity, 25.2%.
Oil viscosity, 133 cp.; aqueous phase, distilled H_2O;
gas phase, nitrogen.
Foam solution: I, Sulfanole FAF, 0.5%;
Agar (stabilizer), 0.02%.
II, Sulfanole FAF, 1.0%.

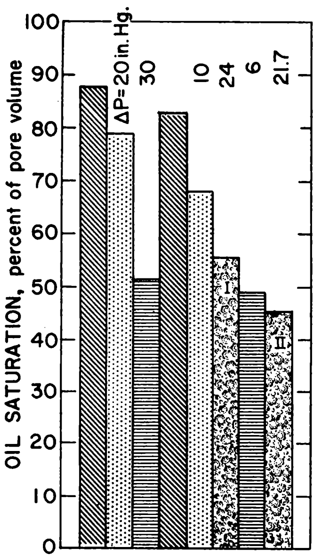

FIGURE 11. - Graphical Summary of Results of Oil-Displacement Test 9-1056.

Unconsolidated synthetic (Pyrex) sand in transparent cell
0.78 cm. diam., 30 cm. long.
Air permeability, 11.3 darcys. Oil viscosity, 30 cp.
Water flood with distilled water.
Detergent-solution drive with 0.5% Petrowet R.
Foam solution, 0.5% Petrowet R. (At end of foam drive, solution was stabilized with 0.01% Duponol WAQ, led to blocking of foam flow.

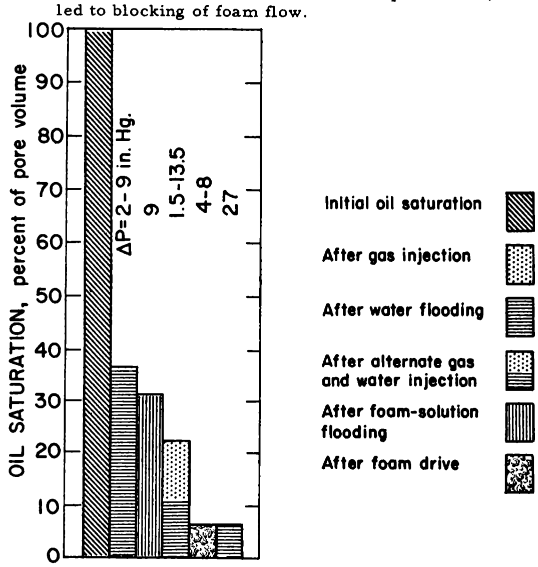

FIGURE 12. - Graphical Summary of Results of Oil-Displacement Test 6-757.

continued foam injection reduced the oil saturation by 22.3 percent of the pore volume, and the ensuing waterflood yielded an additional 12.4 percent. The results of the entire run are shown in figure 10. Owing to the separation between tube wall and sand column and to the resulting channeling of foam, the run was not believed to be truly indicative of the performance to be expected of foam drives. It is noteworthy, however, that the foam drive and the waterflood which followed it produced more oil at a lower ratio of injected-liquid-to-produced-oil than did the earlier conventional water drive (1.11 in the former versus 1.97 in the latter).

Test 9-1056

To obtain better contact between tube wall and sand, a layer of sand was cemented to the inner surface of the tube and the sand was repacked. The air permeability of the sand column was 1.38 darcys or within 40 md. of the permeability of the previous sand column. The porosity was 25.2 or within 2 percent of the previous porosity. Initial water and oil saturations were again established in the new sand-packed column, but this time an oil having a viscosity of 133 centipoises was used. Experience gained during the previous run led to the conclusion that injection of foam into a sand containing 100 percent liquid, of which over 80 percent was high-viscosity oil, was an unnecessarily severe and unrealistic test of the foam-drive method. It was reasoned that application of foam drives probably would be restricted to those oil fields where conventional secondary recovery operations had already been completed. The remaining foam-drive tests, therefore, were run in sands that had been depleted first by waterfloods, then by gas drives.

In run 9-1056, primary recovery was simulated by gas driving (with nitrogen instead of air) and secondary recovery by waterflooding the sand. Oil flooding then reestablished the oil saturation within 3 percent of a pore volume less than the original oil saturation. Primary recovery was again obtained by injecting gas into the sand. Foam for the foam drive in this test was generated from a 0.5 percent Sulfanole FAF, of 0.02-percent agar (stabilizer) solution, using nitrogen as the gas phase. The dispersed driving medium was injected initially at very low pressure. The pressure gradually was raised to 24 in. Hg to maintain an average foam input rate of 0.3 cc./min. The foam drive was followed by water injection and again by foam. In the latter, the original foam solution was replaced with a 1-percent solution of Sulfanole FAF and the resulting foam was considerably more stable than the previously injected foam.

Figure 11 presents a summary of the results of run 9-1056. Lower residual oil saturation was attained by using the foam drives and the intervening waterflood than by using the conventional waterflood, but the ratio of total liquid injected to oil produced in the foam drive was considerably greater than that for the conventional waterflood. The gas saturation after conventional water drives was less than 4 percent, whereas after foam drive and the ensuing water drive there was 27 percent, gas in the sand. This supports the theoretical contention that one of the functions of foam in the displacement mechanism is to increase the trapped-gas saturation. There was a definite tendency for the foam drive to emulsify the oil, as revealed by production of part of the oil in that state. Moreover, in the second foam drive the resistance to the flow of foam developed to such an extent that the sand became virtually blocked and the run had to be terminated.

Visual Study of the Mechanism of Foam Drive

Transparent-Model Tests--1st Series

An apparatus was devised to permit visual observation of the actual behavior of foam as it displaced oil and water from a porous medium made of granulated Pyrex glass packed in a Pyrex glass tube 0.78 cm. in diameter and 30 cm. long. The particle-size distribution of the synthetic sand ranged from 65- to 120-mesh. The average air permeabilities of these sand packs ranged from 11 to 12 darcys; the effective porosity averaged 26.25 percent. When saturated with an oil of the same refractive index as Pyrex (1.474), the column was highly transparent. By means of a microscope mounted on the flow apparatus, flow patterns developed during the displacement tests could be observed readily. Later it was found that the Pyrex sand when saturated with refined lubricating oils had sufficient transparency to permit good visibility to depths of from 5- to 10-grain diameters from the tube wall. A series of 21 tests conducted with the transparent model produced a number of highly significant results.

Effect of Foam Stability on Flow

Two attempts were made to foam drive a 30-centipoise oil from the sand following conventional water and gas drives. Foam progressed only a short distance, 2 to 5 cm., into the sand and became progressively more resistant to flow, finally becoming immobile despite pressures of 25 to 30 in. Hg (above atmospheric pressure) at the upstream sand face. Observation through the microscope revealed the occurrence of two separate processes, both of which may have contributed to the decrease in foam mobility. Foam bubbles entering the sand were observed to redivide into smaller and smaller bubbles as they passed through pore constrictions. Simultaneously, some of the oil in the region invaded by the foam became emulsified and the newly formed oil particles soon became immobile. Either one or both of these actions--foam division and emulsification--could have been responsible for the resulting blockage to flow. When foam was injected with no oil present in the sand, regeneration of the foam and cessation of flow again occurred. When this experiment was repeated with a low-stability foam, the foam moved intact through the entire length of the sand under imposed pressures of 3 to 4 in. Hg. However, even with the low-stability foam, the blocking tendency caused by excessive foam regeneration became evident when flow rates were increased.

From the inception of the foam study, maximum foam stability was believed to be a prime requisite for a successful foam drive. Some degree of regeneration of the foam was anticipated and was considered as necessary to the persistence of the dispersed phase. The foregoing experiments indicate that the degree of foam regeneration should balance the rate of bubble attrition and coalescence. Highly stable foams evidently undergo redivision to a degree out of proportion to the rate of attrition in the reservoir model. Undoubtedly, when regeneration effectively stops further foam movement, redivision ceases until the effects of aging, diffusion, and coalescence of bubbles permit resumption of flow. Experiments showed, however, that with stable foams the period of immobility may last for days before the latter process has progressed far enough to reestablish mobility. Moreover, once flow has again started, the regeneration which caused the stoppage reoccurs and flow again ceases.

On the basis of the experimental evidence, attention was focused on surface-active substances regarded as low or medium foamers. A brief study of the emulsion-forming characteristics of surfactants revealed that high foamers generally are powerful mineral-oil emulsifiers even when these surfactants are present in low concentrations. Emulsification by the lower foaming detergents tends to be much less pronounced, although not in all instances.

The preceding observations were verified by run 6-757 in which the sand column first was totally saturated with a 30-centipoise oil (the refractive index of which matched that of the Pyrex sand), was subjected to a waterflood, a detergent-solution flood, alternate water and gas drives and, finally, foam drives. The results are summarized in figure 12. The foam, generated from a 0.5 percent solution of Petrowet R, flowed at a satisfactory rate under imposed pressure differentials of 4 to 8 in. Hg. At the end of the foam injection period a small amount (approximately 0.25 percent) of a high foamer, Duponal WAQ, was added to the Petrowet R foam solution to test whether additional oil production would result from a more stable foam. The increased foam stability caused almost immediate blocking of flow at injection pressures as high as 27 in. Hg. Attempts to remove the block by waterflooding were unsuccessful.

In the next experiment, run 6-1357, the transparent model was initially saturated with 38-centipoise oil. The oil was then displaced by water injection until the water-oil ratio was 64. Foam was injected using a 0.5 percent solution of Petrowet R in the generator. Injection pressures ranged from 5 to 14 in. Hg, but only a small amount of oil was displaced. The foam-solution concentration was then increased to 1.0 percent and 0.05 percent Duponol EP added to further stabilize the foam. Foam injection progressed normally at first but development of increased flow resistance required higher injection pressures until at 28 in. Hg the sand became almost totally blocked to flow. To remove the block by breaking the foam, a 1 percent magnesium sulfate solution was injected under an imposed pressure of 25 in. Hg. Injection of approximately 2 pore volumes of this solution succeeded in partially breaking the blockage and produced a small volume of emulsified oil. Based on the volume of liquid injected, the oil-displacement efficiency of the foam was no better than that of the conventional water drive. However, the test again verified the detrimental effect that overstabilization of foam has on foam mobility.

The displacement of 30- to 40-centipoise oil from an 11- to 12-darcy sand was not a satisfactory test for evaluating the foam-drive method. Gas and water drives tended to reduce oil saturations to too low a level before gas-oil or water-oil ratios approached what might be considered a typical economic limit in field practice. In the remaining experiments with the transparent model, the oil used had a viscosity of 850 centipoises and the initial saturations included connate water.

The series of transparent-model experiments led to verification of several factors considered in developing the theoretical aspects of the foam-drive method. It had been theorized that injecting gas into a sand containing a foam-forming solution would generate foam in situ. Three attempts were made to verify this contention; and two runs--6-757 and 10-257--were successful. In run 6-757, detergent-solution injection followed by alternate gas and water injection reduced the oil saturation to about the same extent as foam drives following conventional drives in other tests. Again, in run 10-257, gas injection after foam-solution flooding, yielded appreciable oil whereas the solution drive itself produced little or none.

In the transparent-model tests using 850-centipoise oil, waterflooding after foam injection did not effectively advance the foam bank. However, the tests substantiated the theory that foam banks do develop high flow resistance in the larger highly conductive channels. The water then moves through the network of smaller capillaries. This continuity of the water phase throughout the upstream region of the sand prevents the development, across the foam bank, of differential pressures required to move the foam. Owing to the extremely high viscosity ratio between the oil and the water, only small amounts of oil were recovered by flooding after foam injection.

Figure 13 shows the results of the previous two as well as the nine ensuing transparent-model tests using various sequences of conventional gas and water drives and utilizing a number of different detergents for the foam-drive portion of the tests. Most of these runs were terminated when flow resistance became too great to permit required rates of flow at practical pressure levels. In almost every instance the difficulty was traced to oil emulsion formation and to overly stable foams. In spite of this problem, 7 out of the latter 10 oil-displacement tests yielded over 20 percent additional oil as a result of foam injection after gas and water drives.

The almost consistent presence of emulsified oil in this group of experiments led to a closer examination of the influence of the emulsions on the displacement mechanism. Observation through a microscope showed that the emulsified oil particles were much smaller than many pore channels of the sand; yet, the particles, after flowing some distance downstream, became static and formed an emulsion zone. These observations led to the conclusion that factors not heretofore considered were affecting the flow process.

Study of Electrokinetic Effects

One physicochemical phenomenon associated with movement of colloids and emulsions is the electrokinetic effect. In flowing systems the electrokinetic effect is manifested in such phenomena as electroviscosity and streaming potential. It is believed the electrical double layer surrounding colloid particles or developed at solid surfaces in solid-liquid systems, exerts a

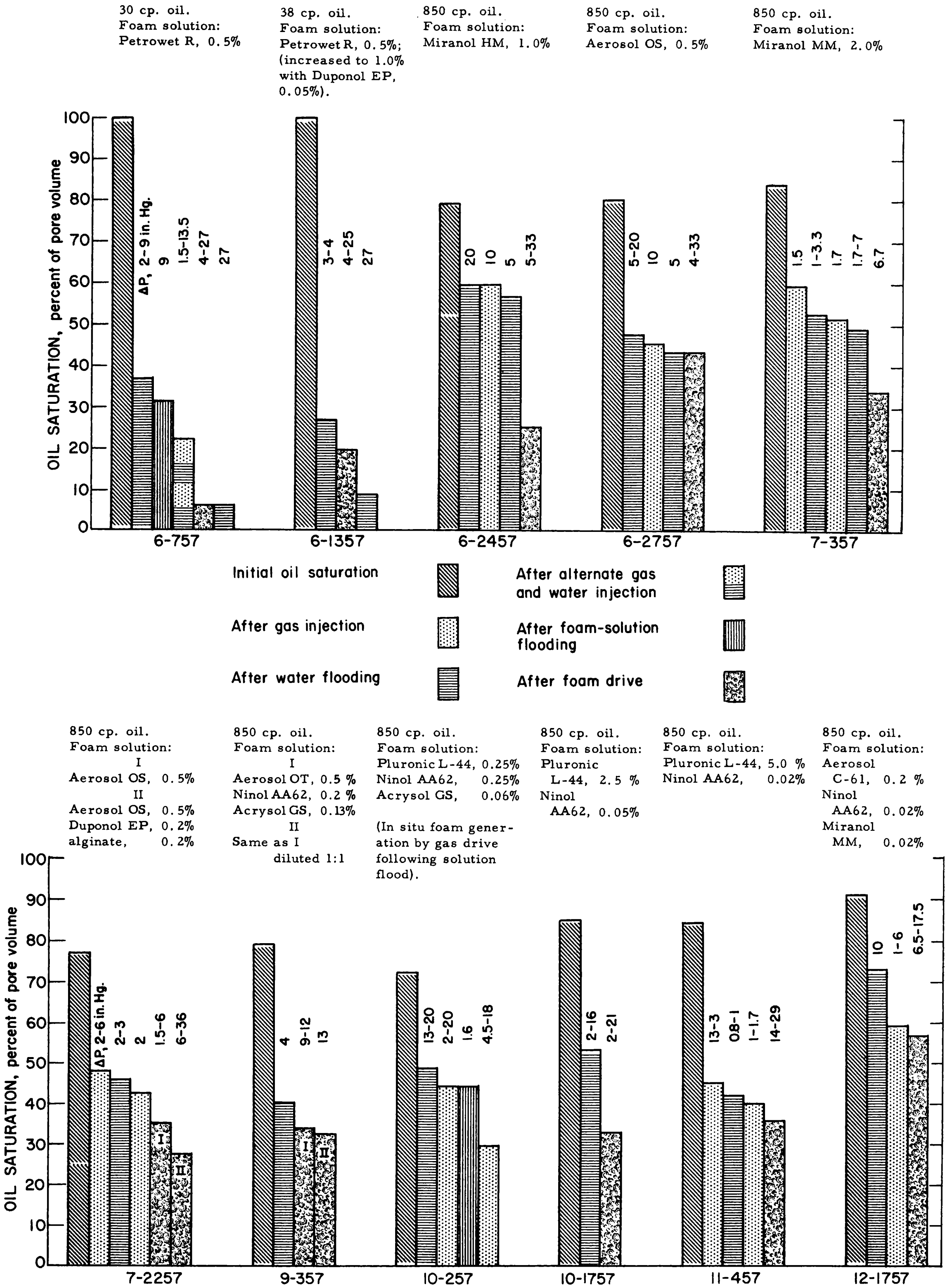

FIGURE 13. - Graphical Summary of Results of Transparent-Model Tests—1st Series.

resistance to flow of the liquid or dispersion medium (19). This resistance becomes a component of the apparent or effective viscosity of the flowing streams. When the emulsion problem became evident, the study of methods for circumventing it led to consideration of electrokinetics.

To determine the extent of the electrokinetic effects in foam and emulsion movement, an apparatus was assembled for measuring the magnitude of streaming potentials developed by foams flowing in capillary channels. The basic element of the device was the capillary viscosimeter previously used to measure the apparent viscosities of foams. A calomel reference electrode was connected to each end of the viscosimeter capillary tube by salt bridges. Electropotentials were measured by means of an electronic potentiometer. Figure 14 illustrates schematically the apparatus used for the study of electrokinetic effects.

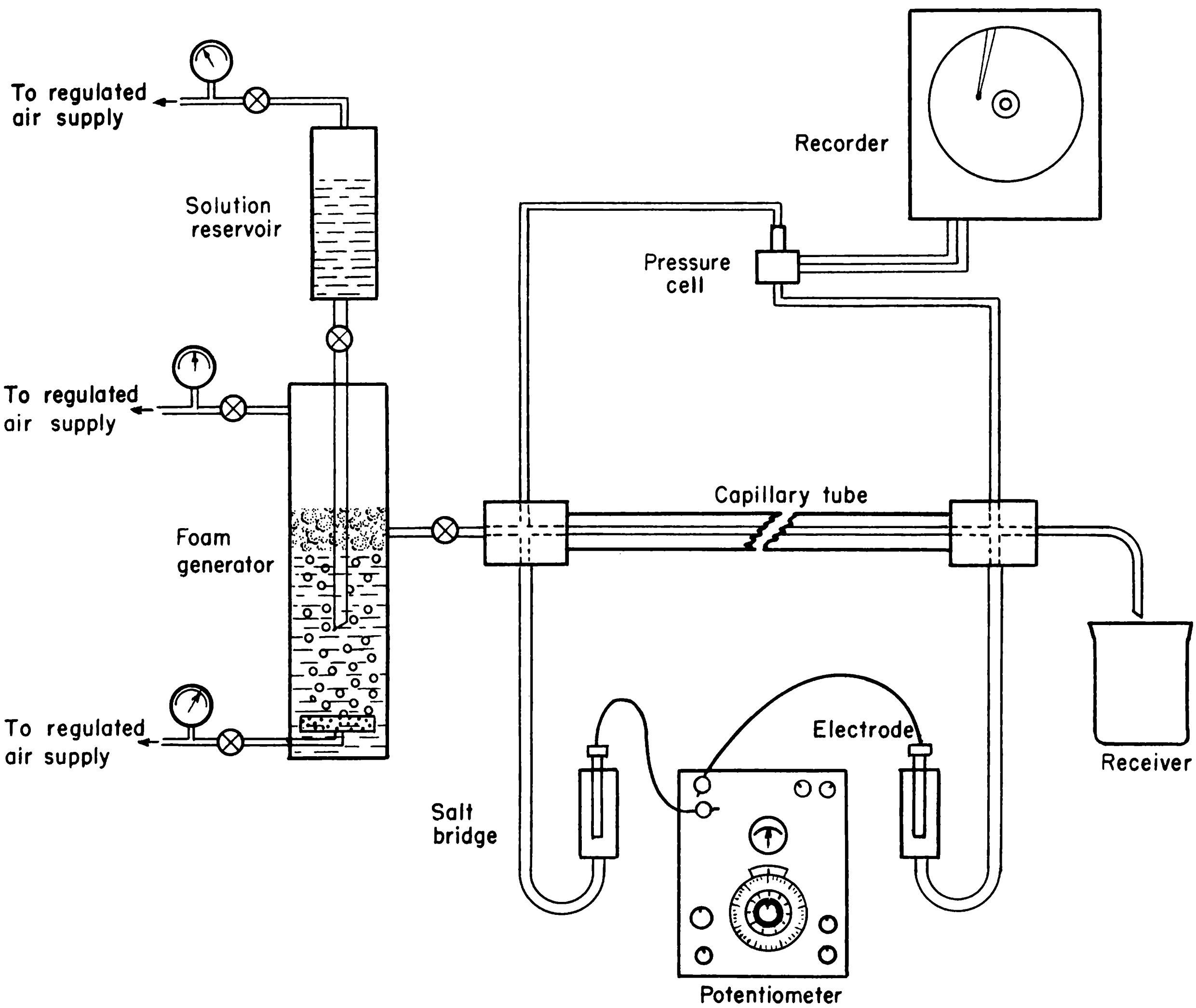

FIGURE 14. - Apparatus for Measuring Streaming Potentials of Foams.

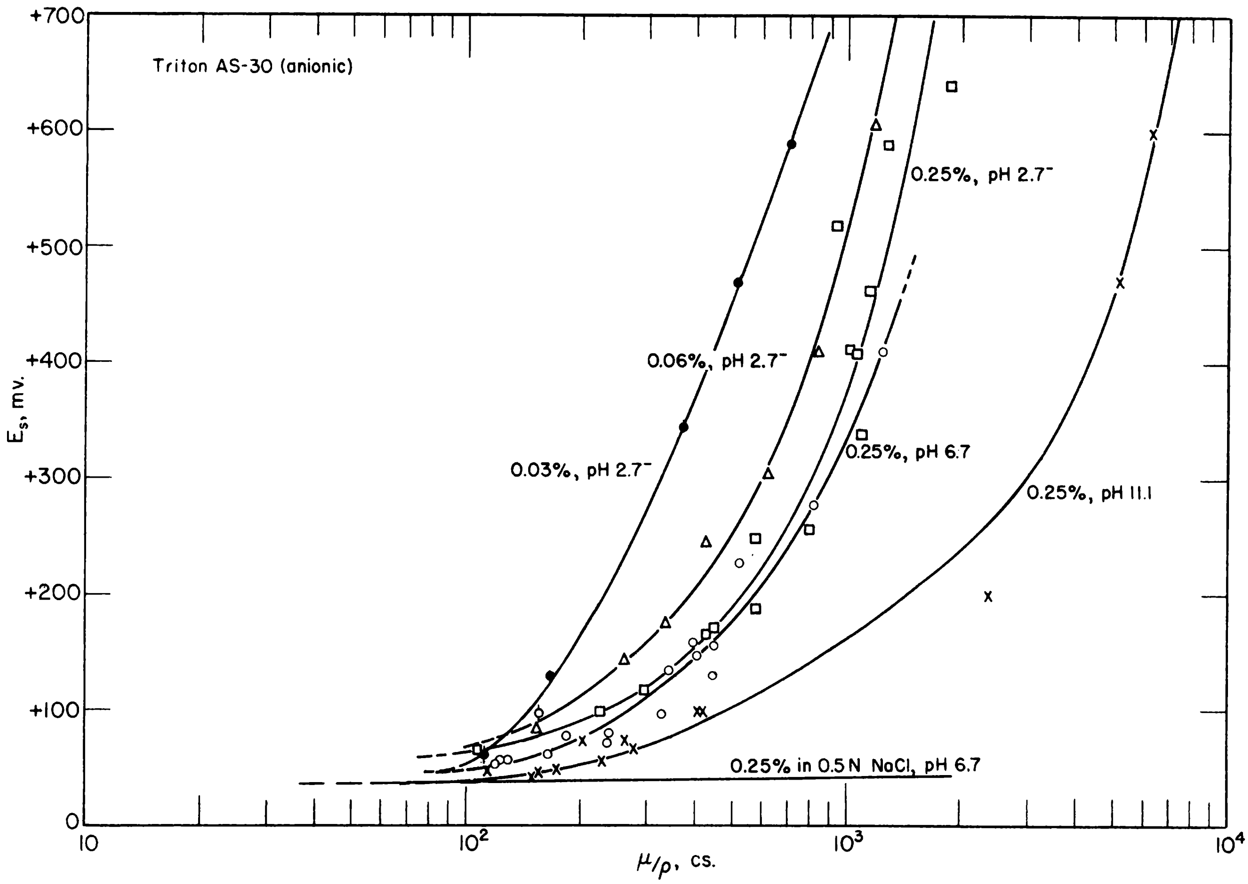

FIGURE 15. - Effect of Surfactant Concentration, pH, and Neutral Electrolyte on Streaming Potentials of Anionic-Surfactant Foam.

The streaming potentials of foams were measured as follows: Nitrogen gas bubbled through a column of surfactant solution caused a layer of foam to form on the surface of the liquid. To control the rate at which the foam was displaced into the capillary tube the pressure in the space above the foam was regulated. The density of the foam entering the capillary tube was varied by raising or lowering the liquid surface to permit newly formed foam at the bottom of the layer or partially drained foam near the top to enter the tube. Weight rates of flow were determined by weighing the foam discharged from the tube during a measured time interval. Volume rates of flow were determined by measuring the traverse time of foam bubbles between two reference marks on the capillary tube. The data recorded were rates of flow, electrical potential, and pressure drop across the tube. From this information apparent viscosity, μ, and foam density, ρ, were calculated and related to the electrical measurement.

The results of these experiments demonstrated that when foams flowed through the capillary tube, potentials as high as 3 volts were developed across the 35-cm. length of tube. The potential, E_s, was found to correlate with the kinematic viscosity, $\frac{\mu}{\rho}$, of the foams. These trends differed according to the ionic type of surfactant and the pH or electrolyte concentration

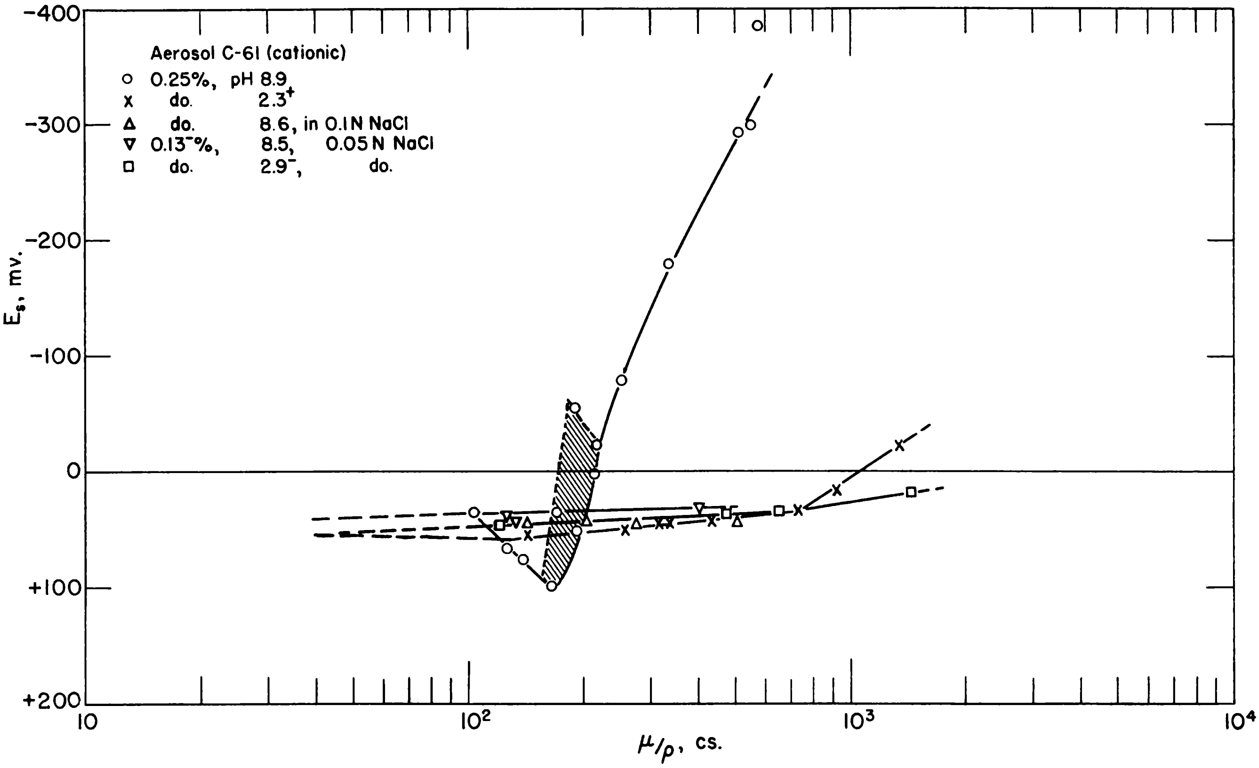

FIGURE 16. - Effect of Surfactant Concentration, pH, and Neutral Electrolyte on Streaming Potentials of Cationic-Surfactant Foam.

of the foam-forming solution used to generate the foams. Anionic surfactant foams exhibited trends shown in figure 15; cationics, as shown in figure 16; nonionics, as shown in figure 17; and an ampholytic, as shown in figure 18.

At low values of kinematic viscosity (characterized by fine-textured foams of low expansion factor, that is, wet foams) all of the surfactants exhibited low positive flowing potentials regardless of surfactant, electrolyte concentration, or pH. With rising kinematic viscosity (viscosity, μ, increasing; density, ρ, decreasing), the streaming potentials of cationic-surfactant foams decreased, finally changing to rapidly increasing negative values when no electrolyte was added or when the pH was neutral to alkaline. When a neutral electrolyte, NaCl, was added or when the pH was rendered acid, cationic-surfactant foams exhibited low E_s values that were nearly constant over a large range of values of $\frac{\mu}{\rho}$.

The shaded portion of the curves shown in the figures indicates a transition from fine foam to coarse foam. To obtain the desired range of $\frac{\mu}{\rho}$, the density of the foam was varied by controlling the rate of foam generation, hence, the length of time the foam was in the generator before it entered the capillary tube. The longer the residence time, the more the liquid drained out of the foam; hence, the lower the foam density. Freshly generated foam was fine-textured and dense. As the foam in the generator aged

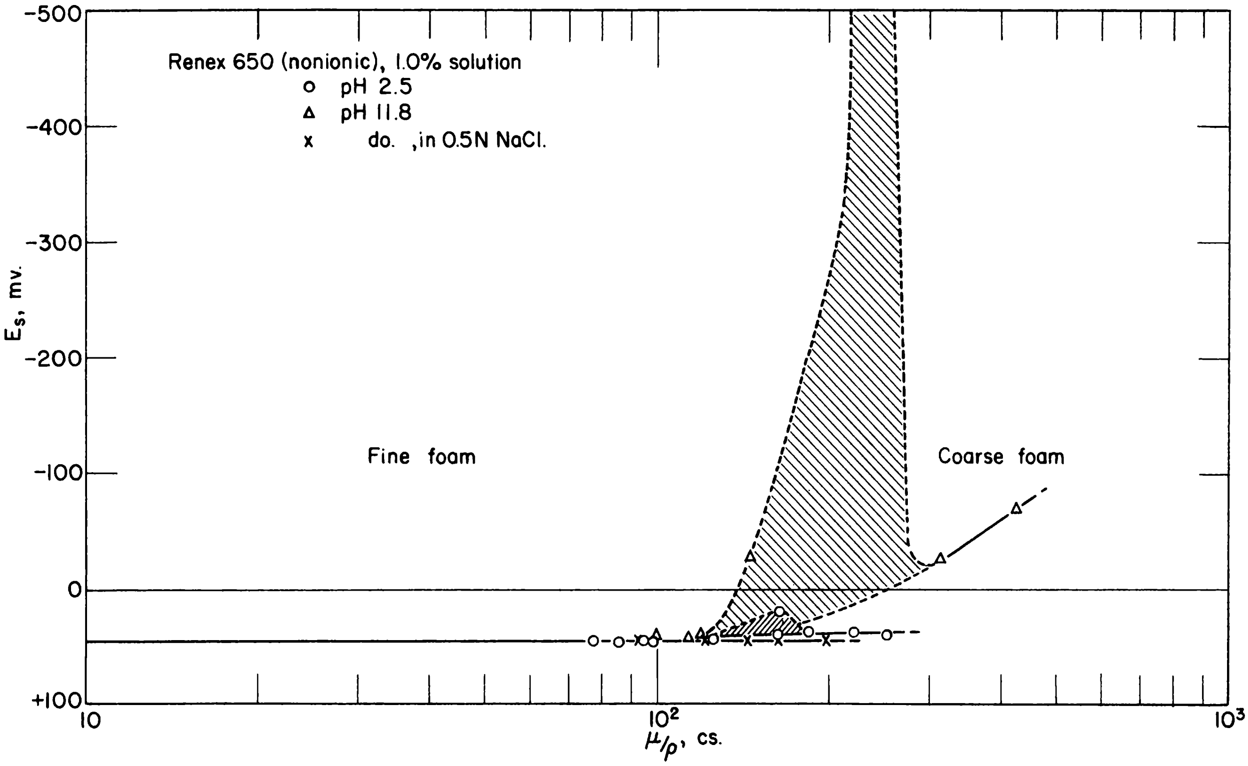

FIGURE 17. - Effect of pH and Neutral Electrolyte Concentration on Streaming Potentials of Nonionic-Surfactant Foam.

and liquid dropped out, the foam passing into the streaming-potential apparatus became drier. Texture remained about the same until a transition occurred during which the filament of foam flowing through the capillary was observed to form alternate bands of fine, thin foam and coarse foam. The transition was completed when the foam again became a continuous filament but of much coarser texture. During the transition period, E_s values fluctuated widely and rapidly depending upon the length and rate of flow of the alternately fine and coarse sections of foam. When the transition was completed, the potentials again settled to a relatively smooth trend. The effects of the transition were absent or nearly so when NaCl was added or acidification eliminated the change in E_s with variation of $\frac{\mu}{\rho}$.

The brief study of electrokinetic effects indicated that foam flow, and presumably oil-emulsion mobility, can develop appreciable flowing potentials in capillary channels. Reducing pH in most instances and adding an electrolyte (such as NaCl) in all cases, markedly depressed and limited flowing potentials to a small negative magnitude. If the countereffect to flowing potentials is manifested in electroviscosity, hence greater flow resistance, the method by which it may be circumvented has been demonstrated in the experiments. In the subsequent transparent-model experiments the validity of this conclusion was tested.

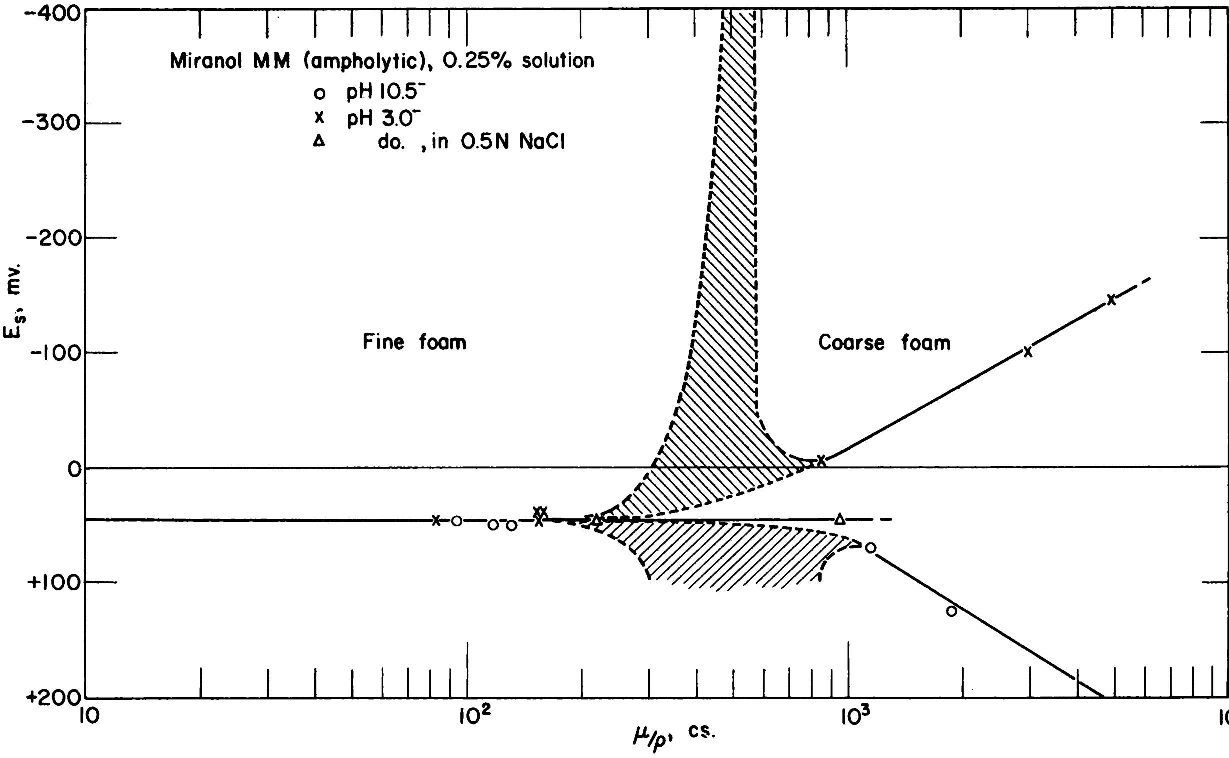

FIGURE 18. - Effect of pH and Neutral Electrolyte Concentration on Streaming Potentials of Amphoteric-Surfactant Foam.

Transparent-Model Tests--2d Series

The primary objective of the first oil-displacement experiments of this series was to determine the extent to which suppression of electrokinetic effects would alleviate the foam blocking and emulsion-zone formation encountered in the earlier tests. In the previous oil-displacement experiments the sand columns were saturated initially with distilled water; in the ensuing experiments a 0.5N NaCl solution was used. All solutions of foam-forming chemicals were made in brine rather than water or were acidified to low pH values. In several instances both salt and acid were incorporated in the surfactant liquid. Moreover, an attempt was made to employ only those surface-active agents known to have relatively low emulsifying power but good or fair foam-forming properties. Generally, this selection tended to exclude the anionic surfactant types because as foamers they are either incompatible with acids and high electrolyte concentrations or they are powerful mineral-oil emulsifiers. Among the nonionics, one having a high HLB (hydrophilic-lipophilic balance) was selected. It has been demonstrated (17) that as HLB values increase, for example, as the number of molecules of ethylene oxide in the surfactant molecule increases, emulsion-forming activity lessens and water solubility and cloud point rise. In addition to the nonionics, several cationic agents showed excellent foam-forming properties and little tendency to form stable oil-in-water emulsions, although a slight tendency to disperse water-in-oil was observed.

Figure 19 shows the results of tests in which the foam liquids either contained brine or were acidified to decrease the pH, or both. Comparison of the results of run 12-1757 (fig. 13) in which the interstitial aqueous phase was distilled water and the foam solution had a pH of 8.9, and run 1-258 (fig. 19) in which the sand initially contained water but the foam solution was acidified to a pH of 2.5, shows that in the former test the residual oil saturation after conventional water and gas drives and foam injection was 57 percent of the pore volume as against 36.5 percent after the same sequence in the later run.

In the remaining tests of the series and in the subsequent long sand column tests the sands were saturated with brine prior to oil flooding. As shown in figure 19, a number of various surfactant foams were tested at different concentrations and produced varying results in runs 5-2058, 6-1158, and 6-2658. However, two significant developments resulted from these experiments.

In order to reveal the manner in which bubbles gained access to the porous system of the transparent model, enough sand was removed at the upstream end to permit visual observation of the sand entry face. In the subsequent experiment the largest foam bubbles not only would not enter the core except under high pressure differentials, but blocked access to the smaller bubbles. Of particular interest was the manner in which the boundaries between adjacent bubble films acted as capillary channels for foam liquid. As the foam came in contact with the sand face the liquid between the layers streamed into the sand and the bubble walls thinned noticeably. If the injection pressure was not high enough to move the bubbles into the sand pores, the films remained static while liquid from the foam in the generator traversed continuous channels between bubble walls and flowed into the sand. Herein was demonstrated the reason why water cannot efficiently act as a driving medium behind a foam bank. Many small bubbles which moved readily into the core with the liquid were observable in the liquid streams. These "secondary" bubbles evidently were not numerous enough to form a foam front without the injection of large volumes of the liquid in which they are carried. It was concluded that a more mobile foam bank might be established under lower injection pressures if freshly generated foams either were much more finely divided or yielded a greater number of "secondary" bubbles. If the latter condition were achievable, and if, by circulating foam across the sand face, a large number of small bubbles could be delivered to the sand face in a given interval of time, the desired foam bank could be established.

To test these concepts, the inlet of the transparent aand column was modified so that foam from the generator was delivered through a hypodermic needle to the sand face and circulated across it while the uninjected residue was removed through the annulus around the needle and flowed to a residue tank. Injection pressures and flow rates were controlled by regulating both the generator pressure and the back pressure in the residue tank. The yield of "secondary" bubbles in the foam was increased by using carbon-dioxide gas to generate the foams.

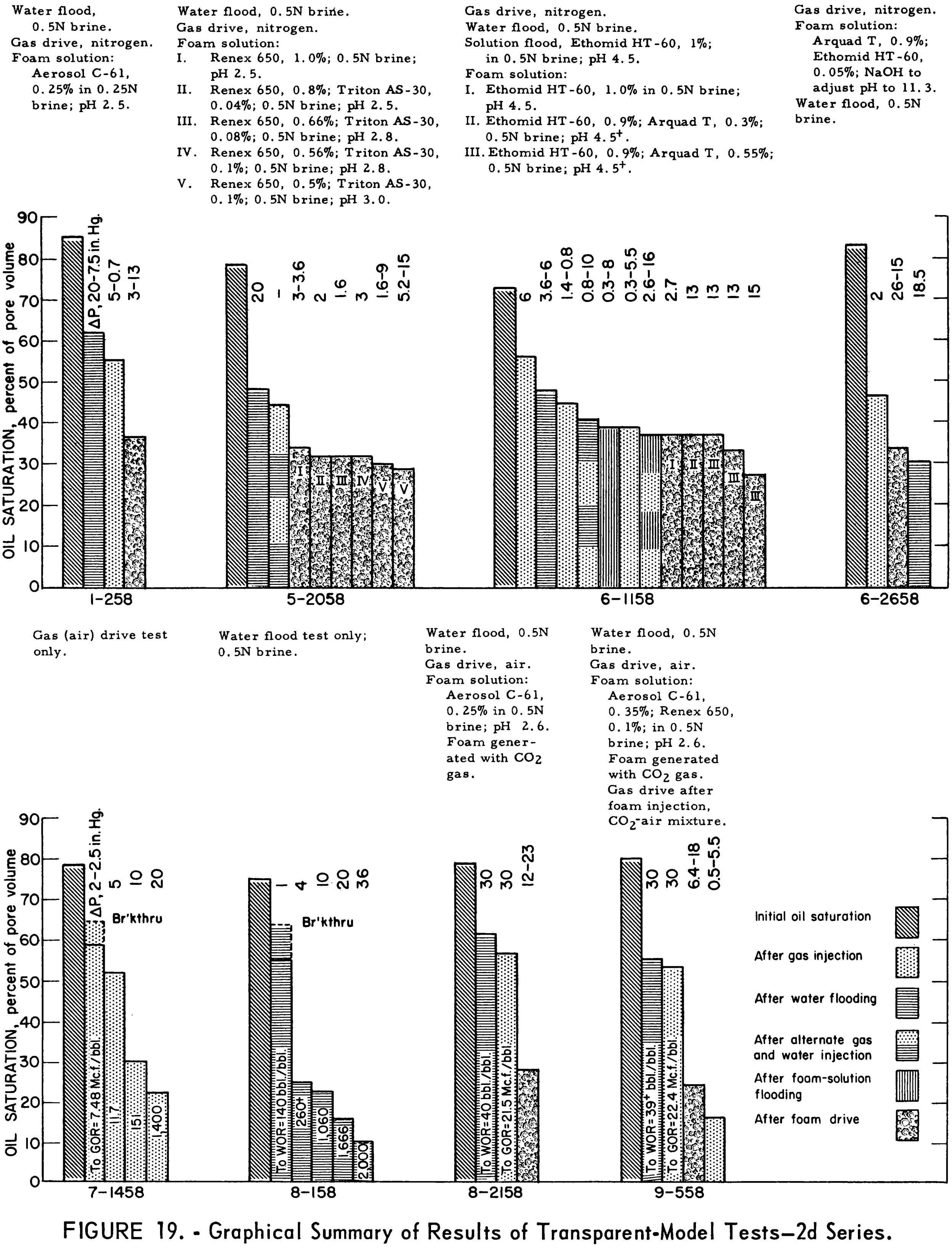

FIGURE 19. - Graphical Summary of Results of Transparent-Model Tests—2d Series.

In the ensuing oil-displacement tests, the new technique proved effective. The results of run 8-2158 are shown in figure 19. After saturating the sand with brine and oil (850-centipoise), the sand was brine flooded to a water-oil ratio of 40 and gas driven (with air) to a gas-oil ratio equivalent to 21.5 M c.f./bbl. Brine flooding reduced the oil saturation from 79.0 percent to 63.9 percent of the sand pore volume; gas injection reduced it to 57.2 percent. Foam was generated by bubbling carbon dioxide through a 0.25 percent solution of Aerosol C-61 in 0.5N brine acidified with HCl to pH 2.5. At the start of the foam drive the displacing medium entered the sand at an injection pressure of only 12 in. Hg. As the foam bank formed, the pressure was raised gradually to 21 in. Hg until foam was observed to have progressed a distance of 1 cm. into the sand. Foam injection was stopped and gas under 18 in. Hg pressure was brought into contact with the sand entry face. Within several minutes, a dark band or bank of oil became clearly visible, extending from 1 cm. downstream of the sand face a distance of 12 cm. along the sand column. The oil bank progressed intact toward the effluent end of the sand until the upstream edge had moved 60 percent of the column length at which time gas breakthrough occurred. Oil recovery at this occurrence was 42.8 percent of the oil in the sand at the start of foam injection; the residual saturation was 32.7 percent of the pore volume. A second foam bank was established, this time by injecting foam until it had invaded the sand a distance of 3 cm., and following this by gas at a pressure of 18 in. Hg. Gas production dropped almost to zero but after increasing the injection pressure to 21.8 in. Hg breakthrough reoccurred and the test was terminated after the gas-oil ratio had risen to the equivalent of almost 2 M c.f./bbl. The final residual oil saturation was 28.6 percent, the cumulative produced water-oil ratio during foam drive was 1.3^{+} and the cumulative produced gas-oil ratio was equal to 98.5 cu.ft./bbl. Total oil recovery by foam drive was equivalent to 994 bbl./acre-ft. The foam drive produced 50 percent of the oil remaining in the sand after water and gas drives.

In foam-drive test 9-558, the same procedure was followed but the foaming solution was slightly enriched to 0.35 percent Aerosol C-61, and 0.1 percent Renex 650 was added. The oil saturations attained at the various stages of the experiment are shown in figure 19. To establish the initial foam bank, foam was injected at an initial pressure of 12 in. Hg which was lowered to 6.4 in. Hg at the start of the gas injection phase. During the entire foam drive a series of gas breakthroughs occurred but each was effectively "shut-off" by injecting small banks of foam as soon as abnormal gas flow became evident. Altogether, seven 1-cm. banks of foam were injected during the test. Oil recovery by foam drive amounted to 36.7 percent of the pore volume or 69 percent of the oil occupying the sand after application of conventional displacement methods. The cumulative water-oil ratio for the foam drive was 1.38 bbl./bbl.; the amount of gas required to displace the oil was insufficient to register on the wet-test meter which can reliably indicate somewhat less than 5 cc. total input. It can be safely stated that the cumulative gas-oil ratio did not exceed the equivalent of 10 cu.ft./bbl. Total oil recovery by foam drive corresponded to 1,209 bbl./acre-ft. of sand.

A significant effect of the foam drives was the immediate reduction in the permeability of the sand to gas. The foams were injected immediately following gas drives which had been terminated when gas-oil ratio exceeded 20 M c.f./bbl. Whereas, gas injected at a pressure of 10 in. Hg flowed through the sand at the rate of 235 to 240 cc./hr. just prior to foam injection, the same pressure moved the gas into the sand at only 0.18 cc./hr. after foam injection. The produced fluids were oil, water, and occasional bubbles of gas.

Long Sand Column Tests--Effect of Viscosity on Recovery

The main objective of the transparent-model experiments were accomplished, and attention was again directed to the effectiveness of the foam-drive method in recovering oil from a long sand column. The primary purpose of the new series of oil-displacement tests was to determine the relationship between oil viscosity and oil recovery by foam drive. For the new series, a stainless-steel tube 5 cm. in diameter and 100 cm. long was used. Five pressure taps equally spaced along the tube provided a means for measuring pressure differentials across the quarter lengths of the sand column. The sand mixture utilized in the former long-core experiments was again used. Figure 20 is a schematic diagram of the sand column and the associated equipment comprising the test apparatus.

Test 12-3058

The average air permeability of the sand pack was 1.9¯ darcys; the porosity, 26.9 percent. Initially, the sand was completely saturated with 0.5N brine and the homogeneous permeability of the column to brine was found to be within one percent of the air permeability. To establish the initial brine and oil saturation conditions, 850-centipoise oil, injected at 20 in. Hg pressure, was flowed through the sand until brine no longer was displaced. The oil replaced 88.6 percent of the brine.

Primary depletion was simulated by brine flooding until the produced water-oil ratio just exceeded 20. For secondary recovery, air was injected continuously until the produced gas-oil ratio exceeded 10 M c.f./bbl. Gas injection pressures averaged 4 in. Hg during the gas drive. Primary recovery had yielded only 11 percent of the oil in place when water breakthrough occurred. However, when the water-oil ratio reached the assumed economic limit, 32.4 percent had been recovered and 59.9 percent of the pore volume remained oil saturated. The ensuing gas injection displaced only 0.8 percent of a pore volume of oil before gas breakthrough occurred and a total of 3.4 percent during the entire gas drive. Thus, after application of conventional displacement methods the residual oil saturation was 56.5 percent of the pore space. By material balance calculations, residual water and gas saturations were 22.8 and 20.7 percent, respectively.

For the foam drive, foam at first was generated by bubbling carbon dioxide through a 0.25-percent solution of Aerosol C-61 in 0.5N brine acidified to pH 6.5. The initial slug of foam was injected by flowing foam across the sand face under an imposed pressure of 5.8 in. Hg, followed by air at the same pressure. Although a steep pressure gradient developed across the upstream section of the sand column, within 24 hours indications that gas

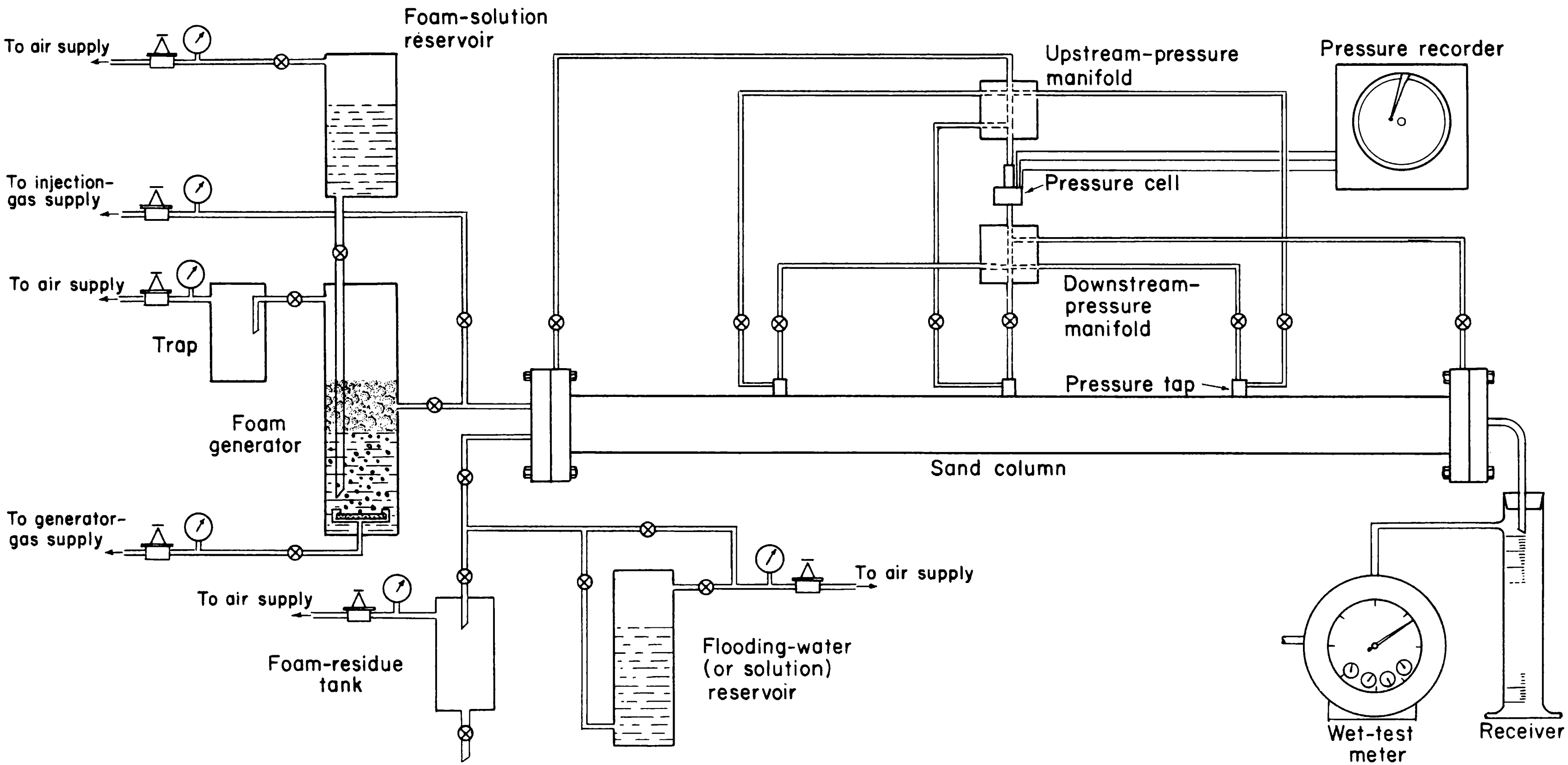

FIGURE 20. - Apparatus for Oil-Displacement Tests in Long Sand Column.

breakthrough was imminent led to the conclusion that either the foam bank was too short to withstand the gas driving pressure or the foam was breaking down in the interstices. A second attempt was made to establish a competent foam bank by injecting foam at 7.0 in. Hg followed by gas at that pressure. The result was the same as that of the first foam injection. To stabilize the foam, the concentration of Renex 650 in the solution was raised to 0.30 percent and the mixture was acidified to pH 2.5. Within the next few days several small banks of foam were injected and seemed competent to withstand the driving pressure of the gas following the foam.

Pressure measurements across the four equal lengths of sand column showed that 80 to 90 percent of the total pressure drop across the column was occurring across the upstream section (one-fourth of the total length of the column). After a total of 26 days, during which additional foam injections were imposed at pressures up to 23 in. Hg, it became evident that the foam bank and any bank of oil that may have formed had not progressed beyond the first pressure tap. During this time, almost 0.8 of a pore volume of aqueous liquids had been produced along with 3.2 percent of a pore volume of oil and almost 2 pore volumes of gas. A discoloration of the produced aqueous liquids raised the suspicion that the acidic surfactant solution was attacking the surfaces of the Monel tube and that this action was somehow related to the immobility of the foam or oil.

To clean out the previously injected surface-active liquids, approximately 1-1/2 pore volumes of a 0.5-percent solution of Ninol 1001 in 0.25N brine were injected. The effluent liquid at first was deep green in color but gradually became colorless. Analysis revealed that the coloration was due to nickel salts which could have come only from chemical attack of the Monel-cell walls by the acidic foam solution. During the flushing of the sand neither gas nor foam was displaced and only 2.1 percent of a pore volume of oil accompanied the aqueous fluids produced. Presumably, then, the foam bubbles that were in the sand just prior to the injection of the Ninol solution were still there. By diffusion and capillary processes the original acidic liquid in the bubble films should have been almost entirely neutralized or replaced by the Ninol solution.

On the basis of the evidence that foam was present in the sand pores, a gas drive was instituted rather than a foam drive. Injection of the gas would displace the bulk of the aqueous liquid and at the same time generate some additional foam in situ. The gas drive was started at an injection pressure of 13 in. Hg--almost one-half the pressure required to inject foam prior to the flushing operation. Over one-half of a pore volume of aqueous liquid was displaced before gas breakthrough occurred. The aqueous-phase desaturation by gas removed less than 1.0 percent of a pore volume of oil.

Figure 21 shows that during the balance of the test the residual oil saturation declined at a fairly constant rate, requiring only a gradual increase in the injection pressure. Gas-oil ratios remained at low values rising slightly with time. To maintain the foam-solution saturation of the sand at a level that would permit in-place generation of foam and prevent dehydration of the foam, small slugs of foam liquid (2 to 4 cc.) were injected

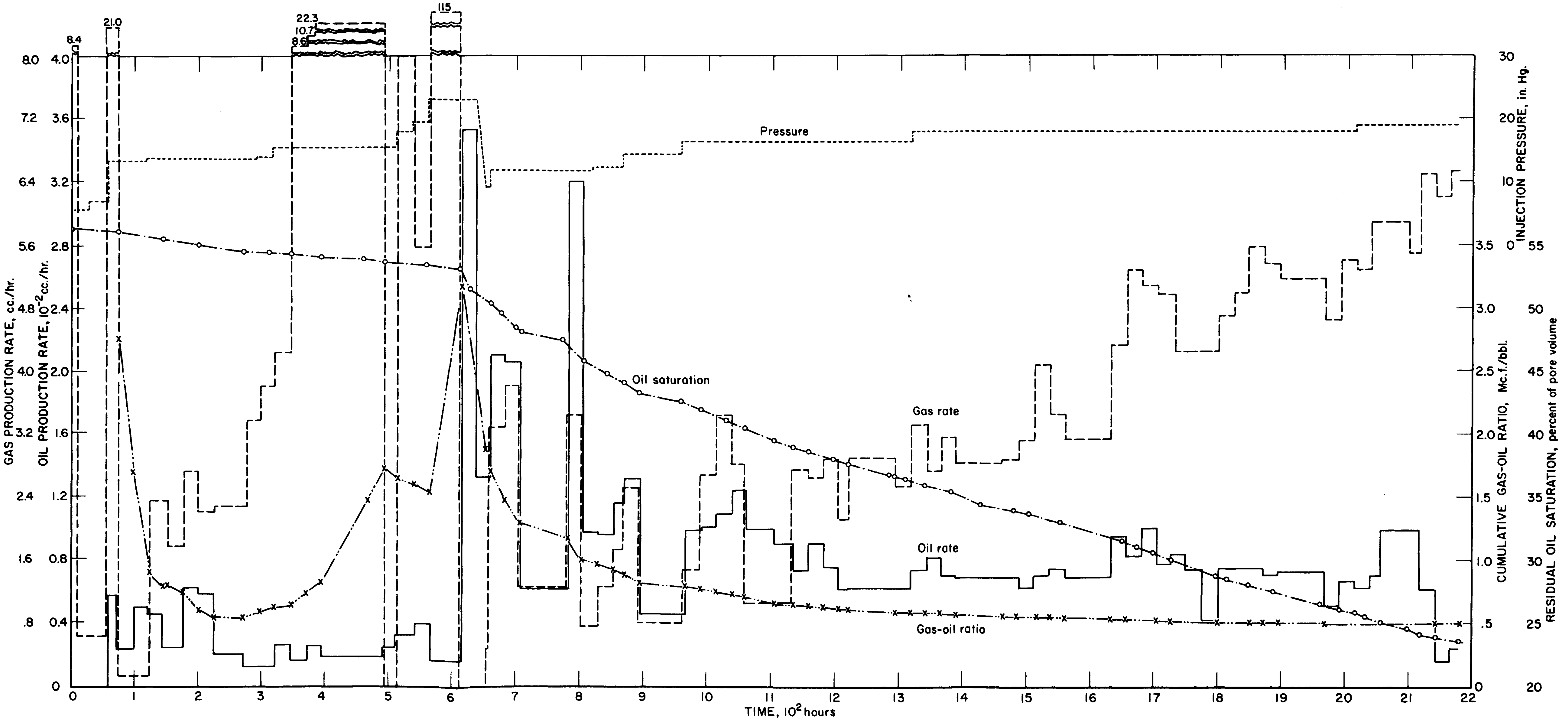

FIGURE 21. - Foam-Drive Performance, Test 12-3058 (850-Centipoise Oil).

whenever the oil production rate tended to decrease or the gas-oil ratio trend showed an abrupt upturn. The test was terminated when the produced gas-oil ratio exceeded 1,000 cu.ft./bbl. and could not be lowered by injecting small slugs of solution or foam. This occurred when the residual oil saturation had been reduced to 23.7 percent of the sand pore space.

Primary recovery by water drive (to a produced water-oil ratio of 40) and secondary recovery by gas injection (to a produced gas-oil ratio of over 10,000 cu.ft./bbl.) together yielded the equivalent of 670 barrels of oil per acre-foot of sand. Foam injection followed by gas injection produced another 680 bbl. of oil per acre-foot of sand. The latter yield was not the ultimate quantity of oil recoverable by the foam drive; it was the amount displaced during the time the produced gas-oil ratios remained below the arbitrary economic limit of 1,000 cu.ft./bbl. The overall efficiency of oil displacement by foam drive, in terms of total gas injected, was 511 cu. ft. of gas per barrel of oil. However, over 90 percent of the oil recovered was produced during the latter half of the foam drive when the ratio was 306 cu. ft. of injected gas per barrel of displaced oil.

Test 7-1759

In the second test of the series, the initial brine and oil saturations were established in the same manner as in the former run. In this test, however, the oil had a viscosity of 273 centipoises, almost one-third that of the oil used in the previous experiment. The sand was subjected to a conventional brine flood at 20 in. Hg injection pressure before foam drive. When the produced water-oil ratio just exceeded 30, detergent solution was substituted for brine and flooding was continued to a water-oil ratio of 73, at which time one-half of a pore volume of solution had been injected. By flowing three-fourths of a pore volume of brine through the sand the detergent solution was displaced. To complete the conventional oil-recovery phase of the test, a gas drive was imposed until the gas-oil ratio exceeded 14 M c.f./bbl. Summarizing, the test to this point had produced the following results: The initial brine flood reduced the oil saturation from 88.4 to 60.5 percent of the void volume, detergent flooding yielded a volume of oil slightly less than 0.7 percent of a pore volume, brine flushing produced another 2.1 percent, and the gas drive further reduced oil saturation from 57.8 to 51.1 percent.

For the foam drive, foam-1 was generated from the same fluid used in the detergent flood; a 0.5 percent solution of Ninol 1001 and 0.05 percent Renex 650 in 0.25N brine solution. The first foam bank (F-1a),[9] injected under 8 in. Hg pressure, proved incompetent and permitted gas to break through after only 1.2 percent of a pore volume of oil had been produced. A second bank of foam-1 (F-1b) followed by 2 small slugs of foam-1 solution (S-1), and later a third foam bank (F-1c) injected at the same pressure, failed effectively to improve the rate of oil depletion but they restrained the gas-oil ratio trend at an almost constant level of 5.5 to 6 M c.f./bbl. Pressure differentials

[9] In figures 22 and 23, points at which foam or foam solution were injected are indicated by the letter F and S, respectively. The numeral suffix indicates the composition of the solution, for example, F-1 means foam-1 solution injected as foam, S-1 means foam-1 solution injected as liquid.

along the sand column showed no indication that a mobile oil bank had formed. During this period a total oil yield of 2.4 percent of a pore volume was recorded. After enriching the foam-1 solution by an additional 0.05 percent Renex 650 the resultant foam-2 was injected in 2 banks at 18 in. Hg (F-2a and F-2b). Foam bank formation and advancement were definitely indicated by the pressure differential pattern along the sand column (see fig. 24). Gas-oil ratios dropped and oil production rates rose abruptly for a period during which 7.5 percent of a pore volume of oil was recovered. However, as the oil production rate continued to rise, the gas-oil ratio trend turned sharply upward until injection of a small slug of foam-2 solution (S-2) and a bank of foam-2 (F-2c) again brought it under control. Subsequent injection of a bank of foam-2 (F-2d) maintained the gas-oil ratio trend almost level but ultimately the influence of steadily decreasing oil saturation was noted in the rise in gas flow rate. In an attempt to deter a rapid rise in gas-oil ratio a solution capable of producing a slightly more stable foam was substituted for foam-2 solution. Foam-3 solution, consisting of 0.25 percent Ninol AA62 and 0.02 percent Renex 650 in 1/8 N NaCl solution, was injected in two slugs (S-3). Shortly after that injection the oil production rate increased sharply. This period was short lived, however, and injection of foam-3 (F-3) in the final stage of the test did not alter the rising gas-oil ratio trend. As indicated in figure 23, the enriched foams and surfactant solutions enabled recovery of an additional 33.6 percent of a pore volume of oil at an average produced gas-oil ratio of 3.77 M c.f./bbl. The final residual oil saturation was just under 13.9 percent of the pore volume.

Figure 22 shows graphically the performance history of the foam drive. Because the flow rates of liquid and gas were erratic, instantaneous gas-oil ratios are not particularly significant and are not shown. The cumulative gas-oil ratio exhibited a marked decline followed by a small increase during the latter part of the test. In spite of recurrent tendencies for gas-oil ratios to rise to very high values, the effectiveness of small banks of foam in generating banks of oil and preventing formation of large numbers of continuous gas-flow channels is evidenced by the low range over which cumulative gas-oil ratios varied. Comparison of the results of the previous test with those of this test shows that gas-oil ratio levels were much higher in the latter. On the other hand, average oil production rates in the two runs were approximately in inverse proportion to oil viscosities. This infers that while the effective permeability to gas was considerably greater in the second test, the oil permeability was about the same as in the first run. The overall performance of the foam drive can best be summarized as follows: In a porous system depleted by conventional water drives to high water-oil ratios (>60) and by a gas drive to high gas-oil ratios (>14 M c.f./bbl.), injection of foam permitted the reduction in residual oil content by 37.2 percent of a pore volume, or, in terms of practical units, 721 bbl./acre ft. of sand, by injecting approximately 1.2 bbl. of foaming solutions and 3,950 cu.ft. of gas, per barrel of oil recovered. To recover over one-third of a pore volume of oil, foam solution injected as foam and as liquid slugs totaled less than 50 percent of a pore volume whereas an even larger volume of detergent solution previously injected during the detergent flood produced only 1 percent of a pore volume of oil when the sand contained a much higher oil saturation.

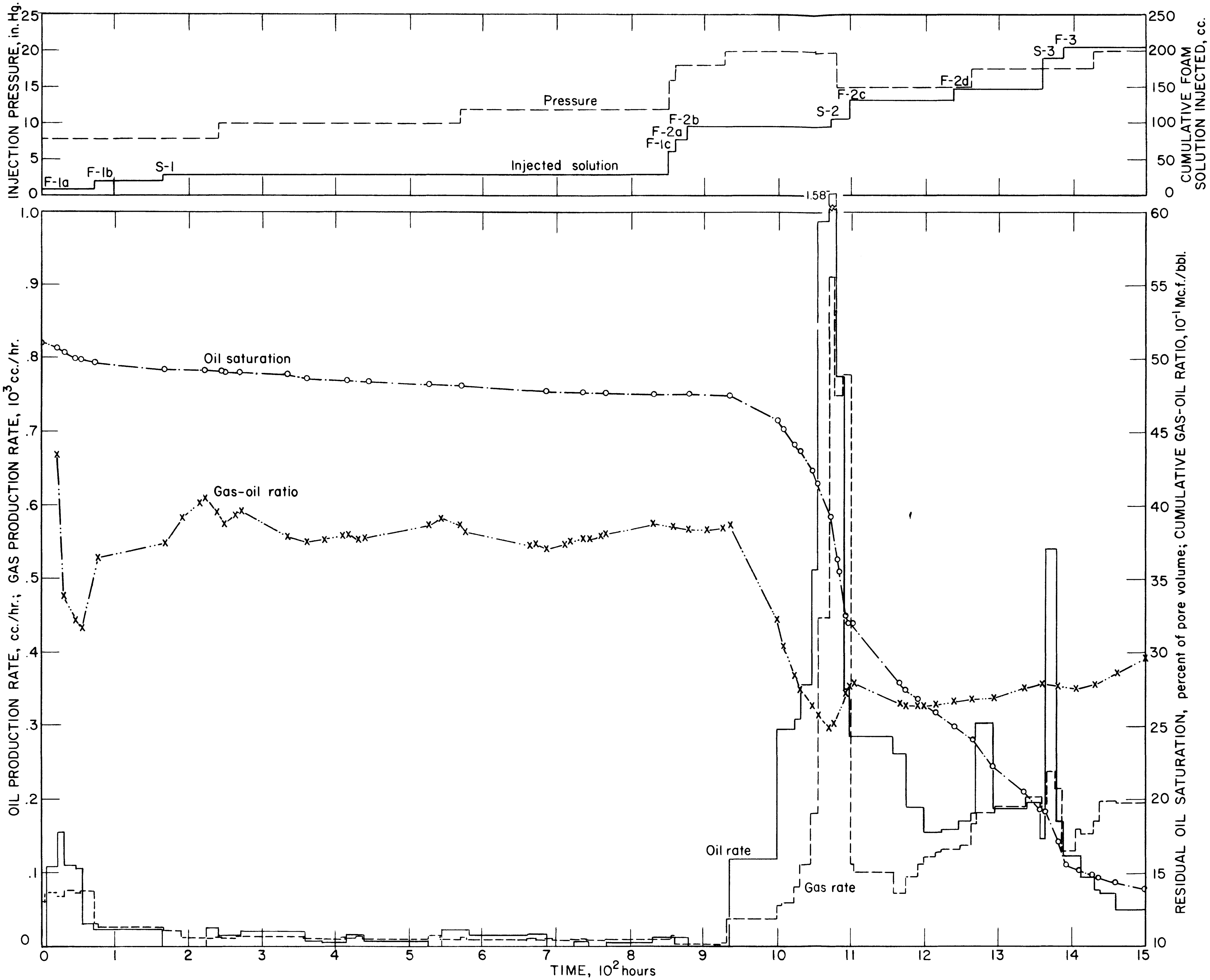

FIGURE 22. - Foam-Drive Performance, Test 7-1759 (273-Centipoise Oil).

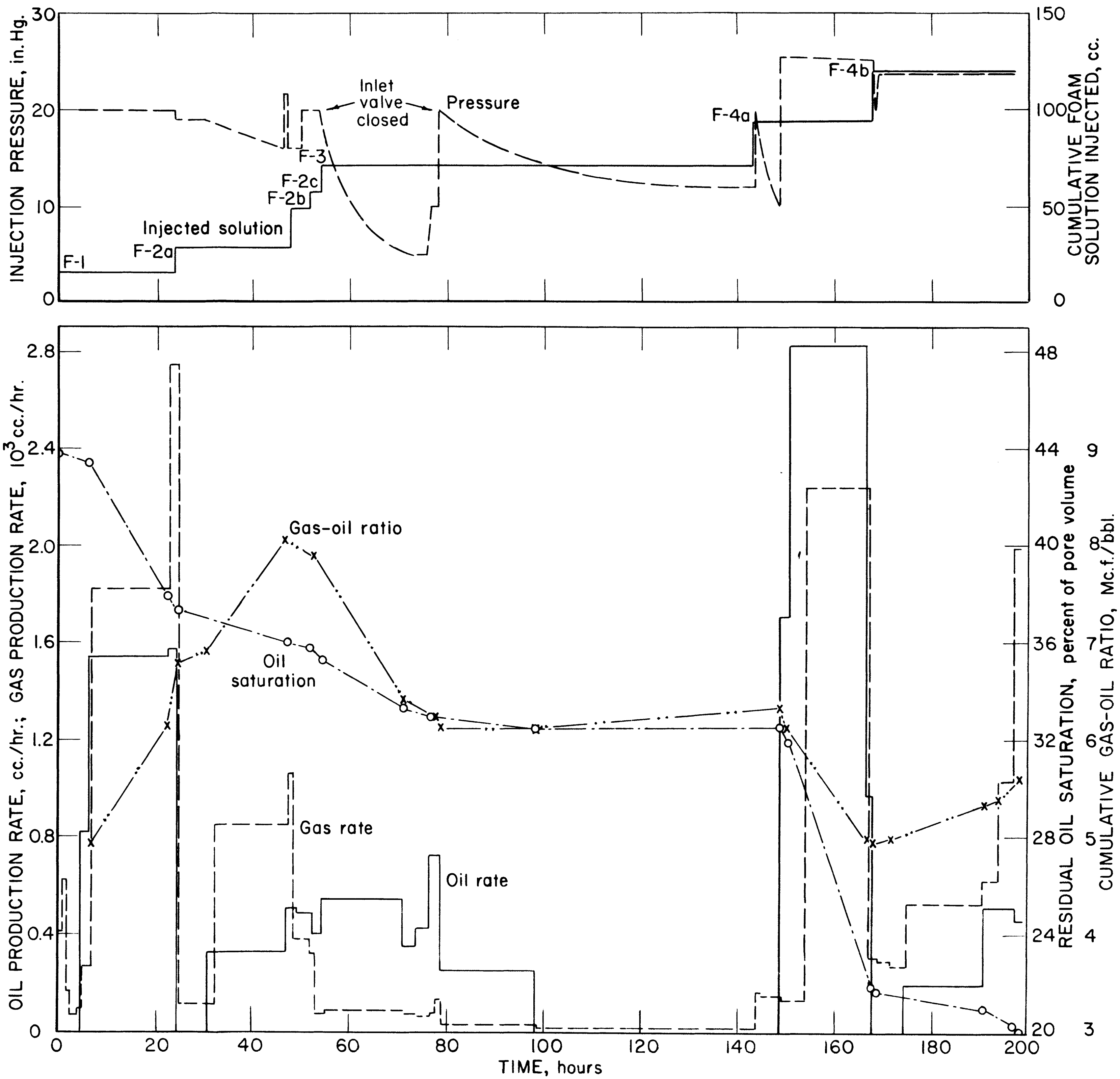

FIGURE 23. - Foam-Drive Performance, Test 11-259 (78-Centipoise Oil).

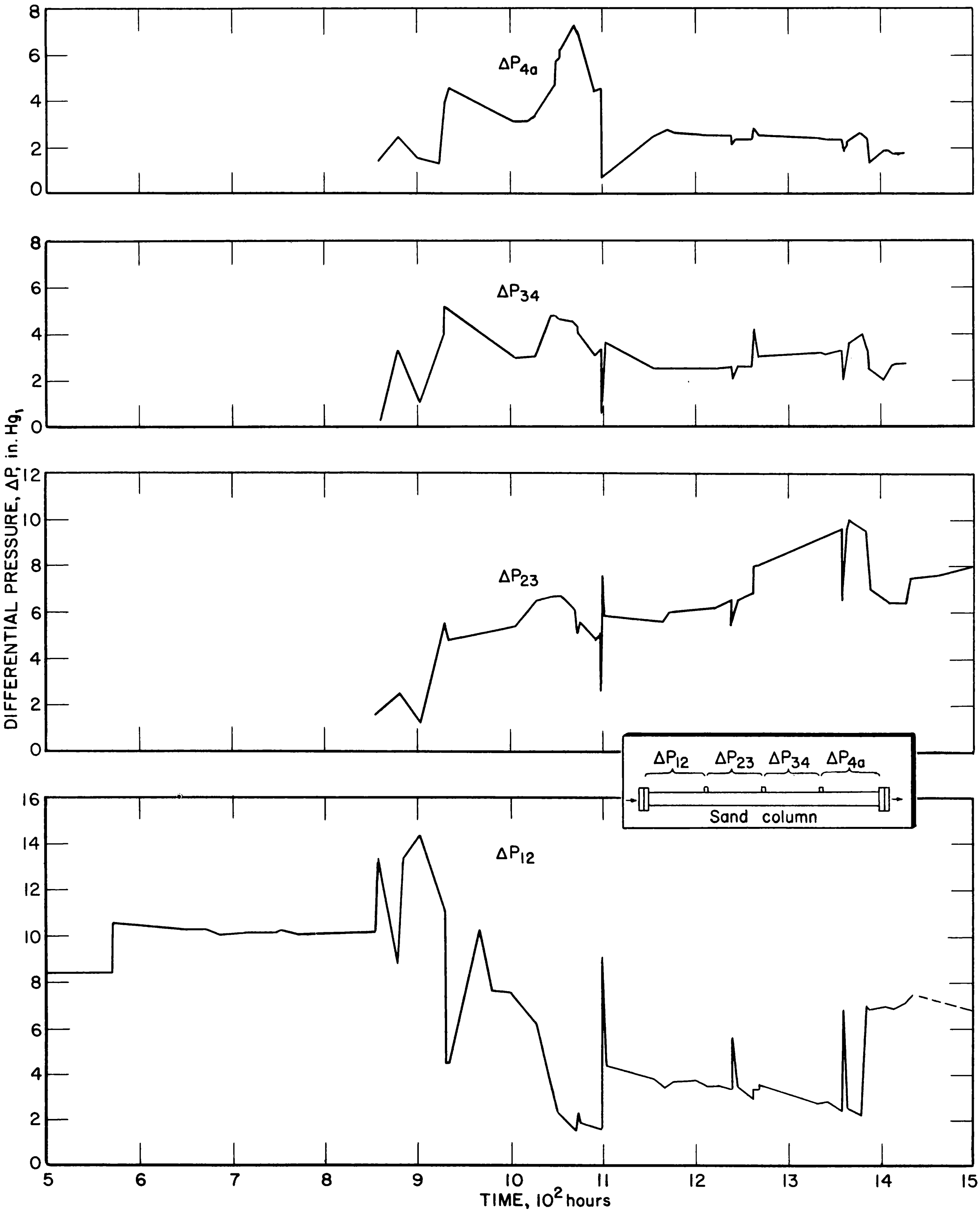

FIGURE 24. - Pressure Gradient History, Foam-Drive Portion of Test 7-1759.

Test 11-259

The final test of the series used an oil of 78-centipoise viscosity. Initial oil and brine saturations, established in the manner previously described, were respectively 86.1 and 13.9 percent of the sand pore space. Brine flooding to a water-oil ratio of 40 reduced oil saturation to 46.2 percent. Brine injection was conducted under a constant pressure of 20 in. Hg. In the ensuing gas drive, air was injected at 8 in. Hg pressure. Owing to lower oil viscosity the residual saturation was reduced to 43.8 percent by the time the produced gas-oil ratio had risen to only 1,556 cu. ft./bbl. As the series was being conducted for comparative purposes, it was desirable that residual oil saturations be of approximately the same order of magnitude at the end of the conventional oil-displacement phase of each test. Accordingly, in run 11-259, the gas drive was curtailed to prevent further oil depletion by gas injection. Extrapolation of the gas-oil ratio trend indicated that at 10 M c.f./bbl. the residual oil saturation would have been approximately 40 percent of the void space.

Figure 23 shows the performance history of the foam drive portion of the test. The foam-forming solution for initial foam injection (F-1) contained 0.2 percent Renex 650 and 0.25 percent Aerosol OT in 0.3N brine solution. The first foam bank, injected under a pressure of 20 in. Hg exhibited poor stability. The first oil production was obtained at an average gas-oil ratio of almost 5 M c.f./bbl. When the residual oil saturation had declined from 43.8 to about 38 percent (pore volume), instantaneous gas-oil ratios suddenly increased to approximately 9 M c.f./bbl. A new foam solution of 0.3 percent Renex 650 and 0.2 percent Ninol 1001 in 0.25N brine with 0.06 Sorbit AC as a clarifier, was substituted in the foam generator and a second bank of foam (F-2a) was injected into the sand. Although the gas flow rate dipped to one-third of the rate prior to introduction of the foam, the gas-oil ratio continued to increase. By the time a third bank of foam (F-2b) was started into the sand column, the produced gas-oil ratio had risen to 15, and the cumulative gas-oil ratio had risen to 8 M c.f./bbl. at a residual oil saturation of 36 percent. Formation of the new foam bank was evidenced by an abrupt drop in the instantaneous gas-oil ratio to 6.3 M c.f./bbl., with an attendant decrease in the cumulative ratio. To improve the effectiveness of the foam bank, a fourth injection of foam (F-2c) was imposed. It resulted in a further reduction in instantaneous gas-oil ratio to 5.5 M c.f./bbl. By increasing the concentration of Renex 650 to 0.5 percent in the foam solution, injection of enriched foam in a fifth bank (F-3), following close behind its predecessor, cut the gas-oil ratio to 0.9 M c.f./bbl. while permitting oil production to continue at a relatively high rate. The period of oil bank depletion yielded 12.1 percent of a pore volume of oil, while the cumulative gas-oil ratio remained almost constant at 6.3 M c.f./bbl.

In an attempt to prevent premature gas breakthrough following foam injection and oil bank formation, the inlet valve was closed with 20 in. Hg gas pressure on the upstream sand face. The pressure was then allowed to bleed down by the production of fluids through the downstream end of the sand column until the upstream pressure had dropped to 5 in. Hg whereupon the valve was opened and pressure again was restored at 20 in. Hg. The procedure was repeated, this time for an extended period of time. During the latter interval the oil production rate dropped to zero as the upstream pressure fell to about 3 in. Hg. However, gas flow continued at a very low rate, presumably supplied by expansion and deterioration of in-place foam. By this means, the average pressure in the sand was reduced to a low level so that a high pressure gradient could be developed for the ensuing foam-injection operation. The fourth foam solution contained 0.2 percent Ninol AA62, 0.5 percent Renex 650 and 0.06 percent Sorbit AC in 0.25N NaCl solution. At the start of the sixth foam injection (F-4a) a pressure of 12 in. Hg was imposed but was gradually increased to 20 in. Hg before gas injection was resumed. As gas flow rate increased without indication of oil production the injection pressure was bled down to 10.4 in. Hg. Within a short interval oil appeared in the effluent. To speed up depletion of the new oil bank, the gas injection pressure was boosted to 25 in. Hg and resulted in rapid production of a volume equivalent to 10.7 percent of the sand pore volume, at an average gas-oil ratio of 3.4 M c.f./bbl. By following the trend of the pressure drop across the downstream section of the column, the passing of the oil bank was detected. As this pressure differential peaked and started to decline, the gas-oil ratio abruptly rose. A bank of foam injected (F-4b) immediately at that time reduced the gas-oil ratio from 3.6 to 1.36 M c.f./bbl., with only 21.6 percent residual oil in the sand. The foam bank effectiveness lasted only momentarily and although oil flow resumed at an appreciable rate, gas flow increased more than proportionately with gas-oil ratios rising to 6.8, 11.3, and 24.4 M c.f./bbl. as residual oil saturations declined, respectively, to 20.6, 20.2, and finally to 20.0^{+} percent, when the test was terminated.

DISCUSSION OF RESULTS

The early series of foam-drive experiments utilizing the small, highly permeable, transparent sand column showed that foams can be injected into the porous medium and, followed by a gas drive, will displace oil not recoverable by conventional displacement mechanisms. In contrast, water injection following foam injection does not effectively propel foam or displace significant amounts of oil.

Although a number of different foam-forming agents were used, no correlation was observed between foam viscosity and oil-displacement efficiency. Instead, the criterion for foam performance appeared to be foam stability. If the foam is too stable, foam bubbles may redivide into progressively smaller particles while they are passing through pore constrictions. It was shown that such redivision, which does reduce the pressure drop required to move the bubbles through a constriction of given size, can increase the viscosity of the dispersed medium to a point where the sand is blocked to flow. Conversely, if foam is very unstable it will not persist long enough to effect formation of an oil bank or to reduce permeability to gas following the foam. Accordingly, the most efficient foams were found to be those generated from solutions of "medium" foamers.

Another noteworthy feature disclosed by the tests was the influence of electrokinetic potentials developed when foams flow through capillaries.

Although only a brief study of this phenomenon was conducted, the results indicated that electroviscosity exhibited by foams was at least partly responsible for eventual blocking of the porous system. A similar action in which oil was emulsified by the dispersing effect of the foam aggravated this condition. Presumably, development of immobile emulsion zones which hampered flow of gas and oil was also a manifestation of electrokinetic effect. The fact that the use of brines as interstitial water in the sand and of electrolytes in the foam formulations alleviated both of these difficulties was interpreted as proof that electrokinetic phenomena were the offending factors.

Of primary interest in the foam-drive study was the role viscosity plays in determining oil recoverability. The initial investigation of foam properties revealed that bulk foams generated from dilute solutions of synthetic detergents exhibit viscosities generally falling within a rather narrow range. Experiments showed that while foam viscosity is not grossly affected by surfactant type, stability is. The factors having greatest influence on the viscosity of a given foam were found to be flow rate, and density or expansion factor. However, when foams move through capillary-size channels, the apparent viscosity is dependent also on the relationship between foam bubble size and capillary diameter. In the flow of Newtonian fluids, flow resistance varies inversely as the fourth power of the channel radius, whereas in foam flow, within limits, resistance to movement increases approximately in direct proportion to the channel radius. The latter statement applies only to systems in which foam movement is characterized by filamental or "plug" flow, that is, flow in which shear is taking place almost entirely in the fluid layer adjacent to the channel boundaries. Since foam viscosity as an intrinsic property cannot be varied over a wide range, the study of the influence of viscosity on oil recovery was based on variation of oil viscosity as the independent variable.

The final series of three tests covering oil viscosities in the range from 78 to 850 centipoises showed no discernible correlation between residual oil saturation and oil viscosity. Owing to alternate formation and displacement of banks of oil in response to injection of banks of foam, the erratic changes in production rates and gas-oil ratios preclude the possibility of comparing tests on the basis of steady-state performance. The primary difficulty stems from the lack of a criterion that defines the range over which variables in one test should be compared with those of other tests. In planning the viscosity-test series it had been decided arbitrarily that each run would be terminated when the produced gas-oil ratio exceeded a pseudo-economic limit of 1 M c.f./bbl. But in the second test the gas-oil ratio never went below 1 M c.f./bbl. and the average was nearly 4 M c.f./bbl. In the third test the average was almost 5.6 M c.f./bbl. and individual gas-oil ratios dipped just below 1 M c.f./bbl. only during production of the second bank of oil.

The tendency for foam drives to exhibit higher levels of gas-oil ratio when lower viscosity oils are being displaced was unexpected. One plausible explanation might be derived from the following observations and reasoning: The course of experimentation demonstrated that for effective oil bank formation to take place a foam of the proper degree of stability must be injected at or above some critical pressure. According to the proposed theory, this pressure is a function of the foam bubble sizes relative to the sand pore sizes. In the experiments the same sand was used in all three tests of the series and for that porous system the critical pressure appears to be between 12 and 16 in. Hg. To move foam, once it is introduced into the porous system, requires a certain minimum pressure drop across both the foam bank and any oil bank the foam has developed. This critical pressure differential is determined primarily by sand geometry and foam-bubble sizes and would be the same for the particular porous system and foam regardless of the viscous nature of the oil. With the very high viscosity oils used in these tests, flow resistance of the oil bank must have been the overall rate-controlling factor. However, the less viscous the oil, the faster it flows in response to the critical pressure. The faster the oil moves, the more rapidly the foam moves behind it. Since the effective viscosity of the foam varies as some inverse function of flow rate, the ratio of effective foam viscosity to oil viscosity decreases with increasing rates of flow. Thus, it is reasonable to expect that faster flowing, low-viscosity oils would not be as efficiently displaced by foams of a given stability as would high-viscosity oils.

On the other hand, it has been proposed in prior considerations that the faster a foam moves through a porous system the greater the degree of foam regeneration; the effect of which should be to increase the viscous resistance of the foam. Theoretically the foam-flow process should tend to be self-regulating, but in the long-column tests the overall results do not seem to substantiate this theory. Perhaps the degree of stability of the foams employed was too low and within too narrow a range to permit regeneration at the low flow rates experienced.

Owing to unsteady flow performance, characterized by formation and production of banks of oil, it is impossible to compare results of the three long-column foam-drive tests on bases generally used for conventional flow mechanisms, that is, gas-oil ratio history, and permeability versus saturation. In seeking a basis for comparison, the net volumes of oil produced per unit of total pressure drop (inch of mercury) across the column were computed for each portion of the foam drive during which the injection pressure was held at a given value. The average rate of oil production for the entire foam-drive portion of each test was then computed and from this value the average effective oil permeability and the average relative oil permeability were calculated. This procedure was applied also to the gas production performance of each of the three tests. The calculated values are shown in table 1.

Comparison of the figures shown in the table reveals several highly important features. First, it is seen that the average relative permeability to oil during depletion by foam drive was almost identical in the three runs, but the average relative permeability to gas differed by a factor of almost 240 between the lowest value, for the 850-centipoise oil test, and the highest, for the 78-centipoise oil test. The low magnitude of effective and relative gas permeabilities is unusual especially because prior to inauguration of the foam drives the sand had been subjected to a conventional gas drive until high produced gas-oil ratios were obtained. Calculations showed that gas relative permeabilities were normal at the residual oil saturations attained during the final stages of the conventional gas drives. At the end of the conventional gas drive in run 7-1759 the effective permeability to gas was 56 md. with 51 percent oil saturation of the sand, compared to an average effective gas permeability during foam drive of 6.6 md. over the range of residual oil saturations from 47.5 to 13.85 percent of the pore volume. At the end of conventional gas drive the effective permeability to oil was 585 md. compared with an average of 196 md. during foam drive. Thus, while the gas effective permeability decreased over eightfold, the average oil permeability was reduced less than threefold as a result of foam injection. If, instead of inaugurating the foam drive, the conventional gas drive had been continued, the oil permeability would have declined virtually to zero by the time the oil saturation had reached an estimated 37 percent of the pore space. Of course, during this process gas-oil ratios would have averaged far above any economically practicable level.

TABLE 1. - Comparison of effective and relative permeabilities exhibited during foam drives in 3 long-column tests

	Test		
	12-3058	7-1759	11-259
Oil viscosity..................centipoises	850.	273.	78.
Average oil flow rate........cc./hr./in.Hg	.0055	.0152	.0433
Average gas flow rate........cc./hr./in.Hg	.2325	9.16	39.6
Effective oil permeability..........darcys	.221	.196	.159
Effective gas permeability..........darcys	.0002	.0066	.0337
Homogeneous permeability...........darcys	1.9	1.55	1.42
Oil relative permeability................	.116	.126	.112
Gas relative permeability................	.0001	.0042	.0237
Average oil saturation, pct. pore vol.....	37.2	30.7	31.9

In run 12-3058, the influence of the dispersed-bubble phase on flow performance was pronounced. As previously described, just prior to the foam drive a gas drive had been conducted until the produced gas oil ratio had exceeded 10 M c.f./bbl. at 56.3-percent residual oil saturation. Calculations showed that with 56.3-percent residual oil saturation the effective permeability of the sand to oil was about 500 md. and to gas, approximately 17 md. After foam injection had reduced the saturation to 35 percent, these permeabilities were, respectively, 190 and 0.1 md; and at 24.2-percent saturation they were 143 and 0.24 md. This means that as oil saturation declined from 56.3 to 35 percent, the k_g/k_o ratio decreased fifty-fold from 0.03 to 0.0006. It then rose only threefold to 0.0017 as oil saturation dropped to 24 percent just before the test was ended.

Attainment of a competent foam bank is accompanied by a sharp pressure drop across the foam-occupied zone of the sand and by a marked reduction in gas production rate. Mobility of the foam bank, of course, is evidenced by the advancement of the pressure front. A study of the pressure-gradient histories shown in figures 24 and 25 when related to the respective production histories shown in figures 22 and 23 indicate that when a foam was injected the pressure drop between the inlet and the first pressure tap rose to a peak

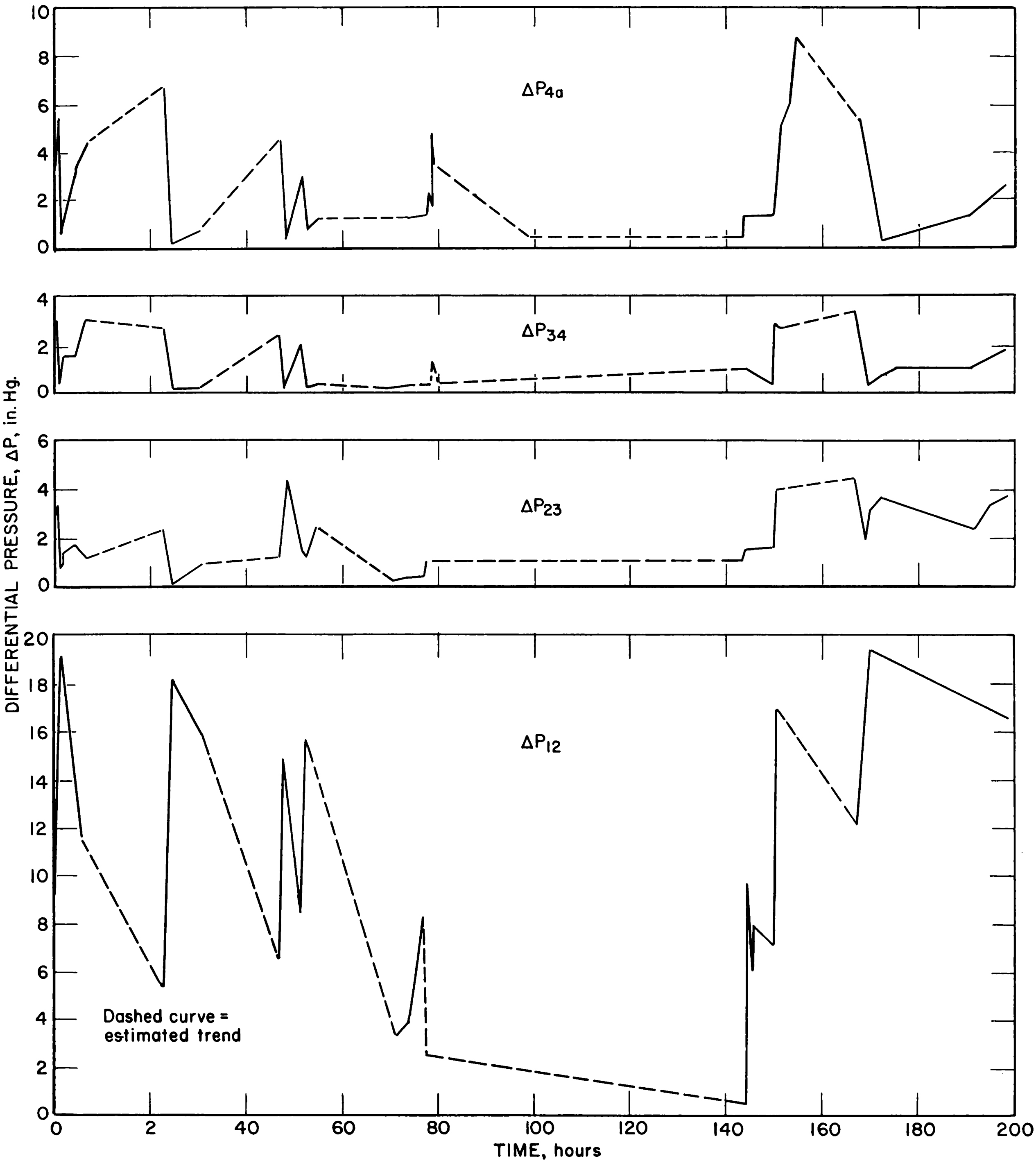

FIGURE 25. - Pressure Gradient History, Foam-Drive Portion of Test 11-259.

while at the same time the pressure gradients across the three downstream sections tended to drop. In many instances the time sequence of the appearance of these pressure peaks at the downstream sections may be followed in the trends of the pressure-gradient history. The correlation between the rise in pressure gradient in the outlet section and the production of a bank of oil is significant evidence supporting the theory of the foam-drive mechanism. The scavenging action of the foam in developing a zone of high oil saturation must result in a decrease in gas flow because the gas permeability in the oil bank is low or even nil. With very high viscosity oils used in this study it would not be expected that gas alone could move an oil bank only a very short distance before breaking through it and exhibiting high rates of gas flow. The conclusion, based on the performance of the tests, is that foam banks push oil banks ahead and act as buffer zones between the injected gas and the oil.

CONCLUDING STATEMENT

The results of this first study of the foam-drive method of oil recovery support to a large degree the major premises set forth in the discussion of the theory. These premises have not been rigorously proved, primarily because fundamental relationships between basic parameters have not yet been quantitatively established. Until the fundamental elements involved in the foam-drive mechanism have been isolated and experimental techniques developed so that the various elements may be controlled and studied, the process must be evaluated on empirical and qualitative bases.

Admittedly, this investigation raises more questions than it answers. The questions, however, concern the interpretation of the results and not the results themselves. Much remains to be done before the foam-drive principle can be brought into the field for application to real reservoirs. In the laboratory the complete evaluation of the mechanism will depend to a great extent on refinement of experimental techniques. A need exists for a better method for following the progress of the foam and the fluid-saturation changes in the sand, for maintaining a complete material balance, for controlling and measuring flow rates, and for continuously recording pressure histories at various points along the test specimen. Ideally, it would be desirable to be able to distinguish between the gas contributed to the effluent stream by attrition of the foam and by the gas injected behind the foam. Similarly, it would be of value to be able to measure the relative amounts of interstitial water and foam solution comprising aqueous-phase production during foam drive.

Another area not studied in the present work concerns the adsorption, by the sand surfaces, of surface-active substances in the foam as compared to similar phenomena observed in detergent-flooding methods. Future studies should attempt to determine optimum size or thickness of banks of foam, particularly in radial flow systems. The investigation of the foam-drive method should be extended to natural oil-field cores of lower permeability and porosity than the porous materials used in this study. There is a whole range of problems concerning chemical compatibilities of surfactant foams and reservoir crude oils, gases and brines. There is the question of possible clay swelling induced by foam-forming chemicals.

Beyond the laboratory, the application of foam injection to actual reservoirs will pose practical problems requiring development of methods and equipment for generating and injecting foams. The techniques for generating foams in situ should be studied further, because this method is simpler and costs less. The results attained in several experiments using that method were highly encouraging.

None of the problems cited appear to be formidable. The large number of surface-active agents now available provide a range of physical and chemical properties that should permit fulfillment of most requirements for application of the foam-drive method to a specific reservoir. Moreover, new synthetic detergents are continually being made available. During the early consideration of the foam-injection process, high reservoir temperatures were considered a serious practical problem. Recently Eakin and coworkers (13) tested a unique method for dewatering gas wells by using foams to carry the water to the surface, They found at least one agent (Triton QS-15) that produced excellent foams capable of withstanding temperatures of nearly 200° F.

In conclusion, the results of the foam-drive study have revealed an entirely new oil-displacement mechanism which can greatly reduce the amount of oil unrecovered by conventional secondary-recovery methods. The author believes that the results obtained in this relatively brief study are sufficiently significant to warrant the additional research and development needed to bring the foam-drive method to the field-test stage.

APPENDIX I. - THEORETICAL ASPECTS OF THE FOAM-DRIVE MECHANISM

Factors Influencing Oil Recovery

The concept of the foam-drive mechanism was developed from an analysis of factors that limit the recovery of oil by immiscible displacement. Each factor has been investigated and is treated in the literature. For this discussion it is necessary only to show what the factors are and how they adversely influence oil recovery. Considerations of means whereby they could be circumvented led to the development of the foam-drive concept.

The fundamental relationships governing the flow of two immiscible phases in a porous system have been well established in the field of petroleum reservoir mechanics (5, 31, 34). For a given rock-fluid system, the relative permeability to each fluid phase is a function of the relative amounts of the fluids present. Figure 26 from Leverett and Lewis' (27) study of steady flow of gas-oil-water mixtures through unconsolidated sands, shows the gas and oil relative permeability-saturation relationships for a water-wet sand. For comparison, curves also are presented to show the same relationships exhibited by the sand when no water is present, that is, when the oil is the wetting phase. Of particular interest are the saturations at which the permeability to one or the other fluid phase disappears. These equilibrium saturations show the theoretical limits to which one fluid can displace another with which it is immiscible.

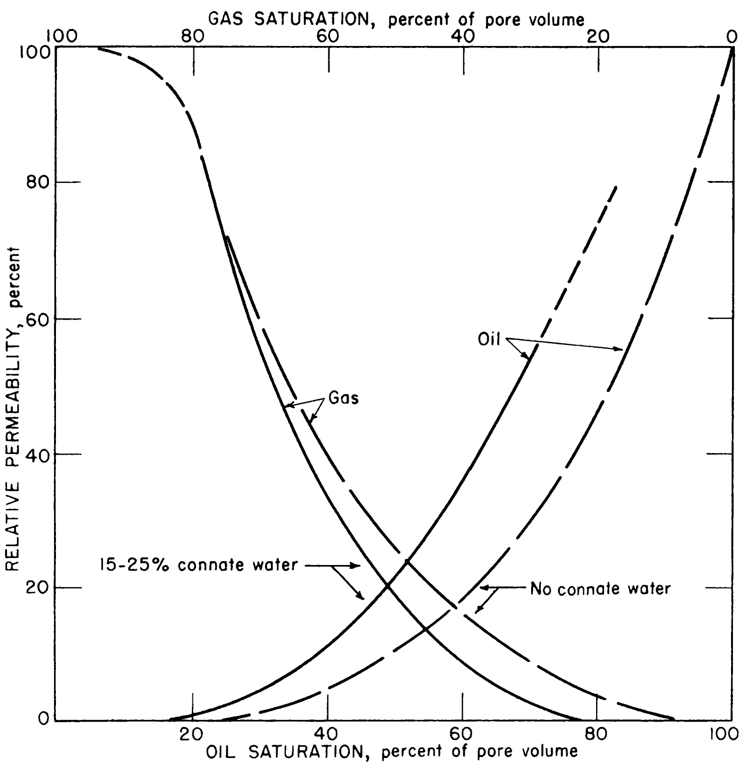

FIGURE 26. - Typical Gas and Oil Relative Permeability Curves for Unconsolidated Sand (After Leverett and Lewis).

In practice, such saturations are almost never reached by ordinary recovery methods. Once breakthrough of the driving medium occurs, the fraction of the displacing phase in the produced stream at the well becomes progressively large and eventually reaches a level beyond which operation of the well becomes uneconomical. In general, the higher the viscosity of the reservoir oil the higher the residual-oil content of the sand at the limiting economic gas-oil or water-oil ratio (12, 14, 15). One of the primary objectives in the newly developed secondary recovery processes using in situ combustion is to gain the advantages of an increased ratio of displacing-phase viscosity to oil viscosity by reducing the latter. Excluding consideration of flow rates, the same effects should result in the displacement process wherein a similar increase in viscosity ratio is attained by increasing the viscosity of the displacing phase. The latter approach (9) is based on the use of certain substances in the flood water to increase its effective viscosity. Unfortunately, at the concentrations required, the cost of the additives makes the method uneconomical under present conditions.

Another feature that prevents the attainment of maximum oil recovery is the heterogeneity of rock properties throughout the oil-bearing strata. Owing to the presence of highly permeable regions and areas of low permeability, fluid movement is not uniform between wells or between outlying regions of the reservoir and the producing wells. Thus, at the time production from the wells has reached the economic limit some parts of the reservoir have been depleted of oil to a degree approaching the theoretical maximum while other parts have been left with close to the initial oil content.

Even without the deleterious effects of nonuniform fluid conductivity of oil reservoirs, a loss of displacement efficiency occurs by virtue of the difference in mobility, k_d/μ_d, of the displacing phase behind the two-phase interface and mobility, k_o/μ_o, of the displaced phase ahead of the front (2, 3, 38). Dyes, Caudle and Erickson (11) showed that for a given well pattern the fraction of the reservoir swept out by the displacing phase is a function of mobility ratio, $\left(\frac{k_d}{\mu_d} : \frac{k_o}{\mu_o}\right)$. The areal sweep efficiency, at various stages of the displacement beyond breakthrough, declines markedly as mobility ratio increases, particularly in systems in which mobility ratios are high, for example, when a low-viscosity displacing phase drives a high-viscosity oil. Accordingly, changes in the viscosity ratio, $\frac{\mu_o}{\mu_d}$, have a two-fold effect on oil recovery; first, in the efficiency with which oil is displaced from regions invaded by the displacing medium; and second, in the areal sweep efficiency of the two-phase system. Systems in which the viscosity ratio, $\frac{\mu_o}{\mu_d}$, is high will not only yield less oil from invaded portions of the reservoir but will also have a smaller fraction of the unit pattern around producing wells swept by the displacing medium.

Additional oil can be recovered from watered-out sands by intermittent injection ("slugging") of gas or air during waterflooding (33, 36). The presence of free gas in the core has the effect of shifting the equilibrium oil saturation to a value somewhat lower than that indicated for the two-phase system of oil and water. Similar results have been reported by Holmgren and Morse (22). In a study of the effect of free gas saturation on oil displacement by water drives, Kyte, and others, (26) found a correlation between the residual oil saturation after flooding and the amount of gas trapped behind the oil bank. The trapped-gas saturation was in turn found to be a function of the mobile gas that was in the porous system before waterflooding was started. Although the advancing water front formed an oil bank which then displaced part of this gas as the oil bank traversed the sand, lower residual oil saturations after waterflooding could be correlated with increased initial gas saturations. It was shown also that in an oil displacement process, up to the time of water breakthrough, the effectiveness of trapped gas was greater for higher viscosity oils than for less viscous oils, but the trapped gas effectiveness[10] diminished with continued flooding after breakthrough. Improved oil displacement brought about by alternate injection of two immiscible phases, such as water and gas, may stem from the piston-like action of the larger number of interfaces moving through the porous system (33). Steward, and others (40) showed that increasing the number of gas bubbles formed in a solution gas drive resulted in abnormally high oil-recovery efficiencies.

The nature of fluid distribution and flow in porous systems depends to a significant extent upon the physicochemical characteristics of fluid-fluid and rock-fluid interfaces. Early investigations brought about a better understanding of the role wettability plays in determining distribution and flow of oil, gas, and water (25). The addition of surface-active chemicals to flooding water for the purpose of altering the natural surface forces between oil, water, and reservoir rock in order to improve the effectiveness of water in removing oil from the porous rock, has been tested in the laboratory and in the field (7, 10, 24, 29, 32, 35, 39, 41). Generally, the use of the surface-active agents to improve ultimate oil recovery by waterflooding has been only moderately successful. Definite improvements in water injectivity, and in chemical treatment of water for flooding have been demonstrated. Experience seems to indicate that insofar as reduction of residual oil saturations is concerned, surfactant flooding shows promise only in reservoirs having oil-wet or "dirty" sands.

As a result of the analysis of the fundamental and some of the practical factors, which act to limit the amount of oil recoverable by known water- and gas-injection techniques, it is possible to set forth a number of requirements for a displacement process which will permit these factors to be circumvented.

1. The process should employ an injection medium mainly using locally available, low-cost materials--air or gases such as flue gas or surplus dry gas from nearby fields. It should not require large volumes of water.

2. The displacing medium should:

   a. Exhibit a high effective viscosity. The increased viscosity ratio between the displacing and displaced phases favors formation of an oil bank and greater displacement and sweep efficiency.

   b. Tend to increase displacing-phase wettability of the rock and thereby promote removal of oil from oil-wet surfaces. The surface-active constituents of the injected medium should resist adsorption by rock surfaces. This feature would permit injected fluid to carry surface-active agents to the advancing front.

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[10] Effectiveness of trapped gas was defined as "the ratio of the reduction in oil saturation at a given flooding stage (below that obtained in the reference flood at the same stage) to the trapped-gas saturation causing this reduction."

c. Act as a temporary selective plugging or retarding agent restricting flow through highly-permeable streaks and previously flushed regions through which channelling or bypassing occurs. The plugging effect would thus tend to redistribute flow into unflushed regions of the pay.

d. Introduce a large number of highly tenacious and elastic interfaces which would exert a piston-type action on interfaces of immobile, discontinuous ganglia or globules of oil.

e. Be compatible with the reservoir-rock minerals and reservoir fluids.

A study of these requirements led to the concept of injecting a gas-liquid dispersed phase, foam, driven by natural gas. Of the possibilities suggested by the prior analysis, foam best fulfilled the basic requirements. This contention was based partly on known principles and partly on hypothesis:

1. Foams exhibit markedly greater viscosities than the separate viscosities of the gaseous and liquid phases of which they are composed.

2. Foams can be generated by dispersing a gas in dilute aqueous solutions of surface-active agents. Air, reservoir gas or other gases readily available in large quantities at low cost are suitable. The low ratio of liquid-phase volume to gas-phase volume in foams reduces the requirement for large volumes of water.

3. Injection of foam into the rock pore system introduces a large number of rigid, yet resilient, interfaces which exert a piston-like force on discontinuous oil masses lodged in the interstices. The large number of mobile interfaces of various sizes and curvatures, greatly increases the probability that the required force or combination of forces will be brought to bear on static oil masses and move them to the producing well.

4. The injection of a dispersed-fluid phase alters the flow patterns and fluid distribution, thereby changing the permeability distribution so that the driving medium invades previously bypassed portions of the sands.

5. In oil-wet or partially oil-wet formations the detergent and wetting effects of surface-active agents used to generate foams promote oil removal from rock surfaces.

6. Since surface-active agents occur as adsorbed molecules in the gas-liquid interfaces forming foam-bubble walls, the tendency to be adsorbed by rock-mineral surfaces will be more strongly opposed than in surfactant-solution floods.

7. The presence of a discontinuous gas phase formed by the foam increases the free gas saturation of the sands without creating high gas-oil relative permeability ratios. Thus, to some extent, foam tends to produce the effect of a trapped gas.

Movement of Bubbles in Capillary Systems

In a solution-gas drive, minute bubbles of gas evolved by the oil are carried downstream with the oil in response to a pressure gradient, through many tortuous paths in the porous rock. With migration of the streams to regions of lower pressure, expansion of previously evolved gas, evolution of new gas particles, and coalescence of some of the particles form a dispersion of discrete gas bubbles of various sizes. Bubbles smaller than pore openings and constrictions along the flow paths pass with relative ease. However, when the diameters of bubbles exceed those of the pore constrictions the bubble interfaces may not, or may only partially, enter small openings under local pressure-gradient conditions. In water-wet sands this development of a discontinuous gas phase may simultaneously break the continuity of the oil phase.

The role of the fluid-fluid interface in the coincident movement of liquids and gases through porous media was probably first revealed by Jamin (21, 23). The "Jamin effect" has been in the terminology of petroleum reservoir engineering since researchers recognized the real function of gas in the oil-expulsion mechanism. Whereas advancement of oil production technology caused the realization that gas dissolved in the oil was an important source of expulsive energy, Herold (21), Tickell (42), Gardescu (16) and others attempted to show that capillary effects, manifested in the Jamin action of a dispersed-gas phase, could be highly restrictive to oil flow.

It can be shown (1) that the pressure differential across a curved meniscus is

$$\Delta P = p_1 - p_2 = \gamma \left(\frac{1}{r_1} + \frac{1}{r_2} \right) \tag{1}$$

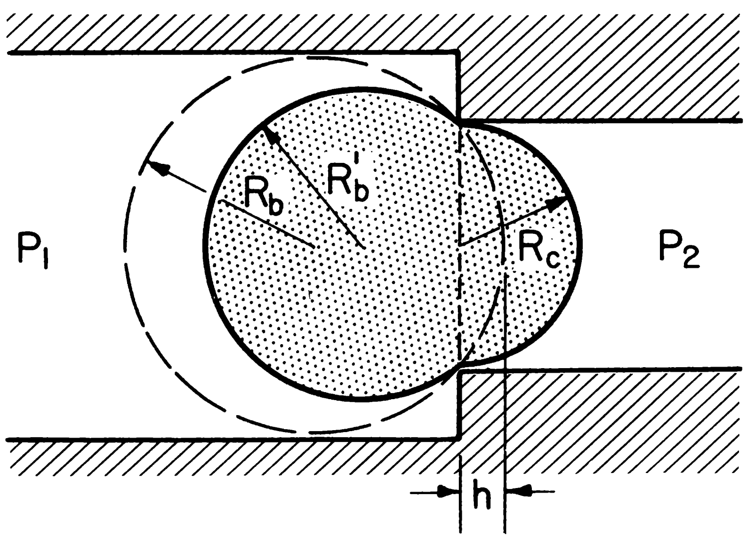

FIGURE 27. - Schematic Diagram of a Bubble Penetrating an Abrupt Constriction.

where p_1 and p_2 are, respectively, the pressures on the concave and convex side of a meniscus of principal radii r_1 and r_2, and γ is the interfacial tension between the two immiscible fluids forming the meniscus. Gardescu (16) showed that the differential pressure, ΔP, required to move a bubble of gas through a pore constriction is dependent on the radius of curvature, R_1, of the trailing surface of the bubble when the forward interface has attained the radius of curvature equal to the radius of constriction (R_2):

$$\Delta P = 2\gamma\left(\frac{1}{R_1} - \frac{1}{R_2}\right). \tag{2}$$

Equation (2) is a general statement based on the assumption that both upstream and downstream contact angles are zero and hysteresis is absent. Moreover, it applies to a bubble having the same fluid-fluid contact at its upstream and downstream surfaces.

Figure 27 is a diagram of a capillary in which a spherical bubble of radius R_b has reached an abrupt constriction of radius R_c. By equation (2), the differential pressure required to move the bubble through the constriction will be just slightly greater than

$$\Delta P = P_1 - P_2 = 2\gamma\left(\frac{1}{R_b'} - \frac{1}{R_c}\right). \tag{3}$$

Note, in equation (3), R_b' is the radius of the trailing surface of the bubble when the downstream surface has been distorted to the radius of the constriction, R_c. Disregarding compressibility effects and considering only the change in the geometry of the bubble as it undergoes distortion it can be shown that

$$R_b' = \left[\frac{1}{2}\left(3R_b^3 - R_b^2\sqrt{R_b^2 - R_c^2} - \frac{R_c^2}{2}\sqrt{R_b^2 - R_c^2} - R_c^3\right)\right]^{\frac{1}{3}}. \tag{4}$$

If the ratio R_b/R_c is defined as c, equation (6) may be normalized to

$$R_b'/R_c = \frac{1}{\sqrt[3]{2}}\left(3c^3 - c^2\sqrt{c^2 - 1} - \sqrt{c^2 - 1} - 1\right). \tag{5}$$

The effect of the ratio of bubble radius to constriction radius on the radius of curvature R_b' may be shown by means of equation (5). A study of the equation reveals that as $\frac{R_b}{R_c}$ increases from unity, $\frac{R_b'}{R_c}$ will be smaller than $\frac{R_b}{R_c}$ by a maximum of about 11 percent at $\frac{R_b}{R_c} = 1.1$. However, this difference declines rapidly to values less than 1 percent when $\frac{R_b}{R_c} > 4$. Thus, in determining the pressure differential required to force a bubble of given radius through a pore constriction of given radius, the correction for the difference between R_b and R_b' is insignificant and equation (2) may be written

$$\Delta P = 2\gamma\left(\frac{1}{R_b} - \frac{1}{R_c}\right) \tag{6}$$

If the upstream interfacial contact is different from that at the downstream bubble interface, for example, water-gas at one, gas-oil at the other, two interfacial tensions and two contact angles must be accounted for in the equation. Let γ_{12} and θ_{12} designate, respectively, the upstream interfacial tension and contact angle; γ_{23} and θ_{23} the same characteristics at the downstream surface. The pressure drop across the former meniscus will be $2\gamma_{12} \dfrac{\cos \theta_{12}}{R_b}$; across the latter, $2\gamma_{23} \dfrac{\cos \theta_{23}}{R_c}$. Hence, equation (6) becomes

$$\Delta P = 2\gamma_{12} \frac{\cos \theta_{12}}{R_b} - 2\gamma_{23} \frac{\cos \theta_{23}}{R_c} . \tag{7}$$

The foregoing treatment applies to essentially spherical bubbles penetrating a constriction formed by an abrupt change in channel radius as shown in figure 28. In porous media comprised of nominally round or angular sand grains often consolidated by cementatious materials the occurrence of such sharp constrictions probably is rare. The majority of flow-path constrictions are rounded or tapered narrowings. Spherical bubbles traversing such constrictions undergo a more gradual deformation during which they are elongated and the ratios of the radii of the trailing to that of the leading menisci are less than those for the same bubbles passing through a sharp constriction. It would be expected that ΔP computed from equations (6) or (7) would be considerably higher than the actual pressure differential required in reservoir rock.

Foam Properties and Foam Movement in Capillary Systems

Foams are colloidal systems which, like emulsions, exhibit non-Newtonian or anomalous flow properties. In emulsions of oil-in-water, there is a tendency for the oil globules to concentrate by gravity at the surface of the body of emulsion. Foams exhibit an analogous tendency; that is, the liquid between the bubbles tends to drain out of the foam. As drainage takes place, a foam undergoes changes which affect its properties. At first, bubble surfaces become closer together as the free liquid separating them is removed. Then, as liquid from the bubble films drains away, the films become progressively thinner until rupture becomes imminent. In the early stages of drainage the rate of fluid movement is relatively rapid, governed to a great extent by the bulk liquid viscosity. Thus, if concentration of foam-forming chemicals in the foam solution influences liquid viscosity it must also influence drainage characteristics. During the film-drainage stage the fluid-loss rate is much slower owing to the high surface viscosity of the liquid remaining in the bubble walls (4, pp. 98-112). Bulk flow properties of foam must thus be dependent to some extent upon the state of drainage and hence upon the age of the foam. In comparing foams, Miles, Shedlovsky, and Ross (28) showed that drainage rate increases as foam bubble size decreases. In a water-wetted porous medium the capillary retention of the wetting liquid would tend to counteract the drainage process.

Another factor to be considered is expansion factor, that is, the ratio of foam density to liquid density or the ratio of the volume of foam to the volume of liquid in the foam. Consideration of this parameter will reveal

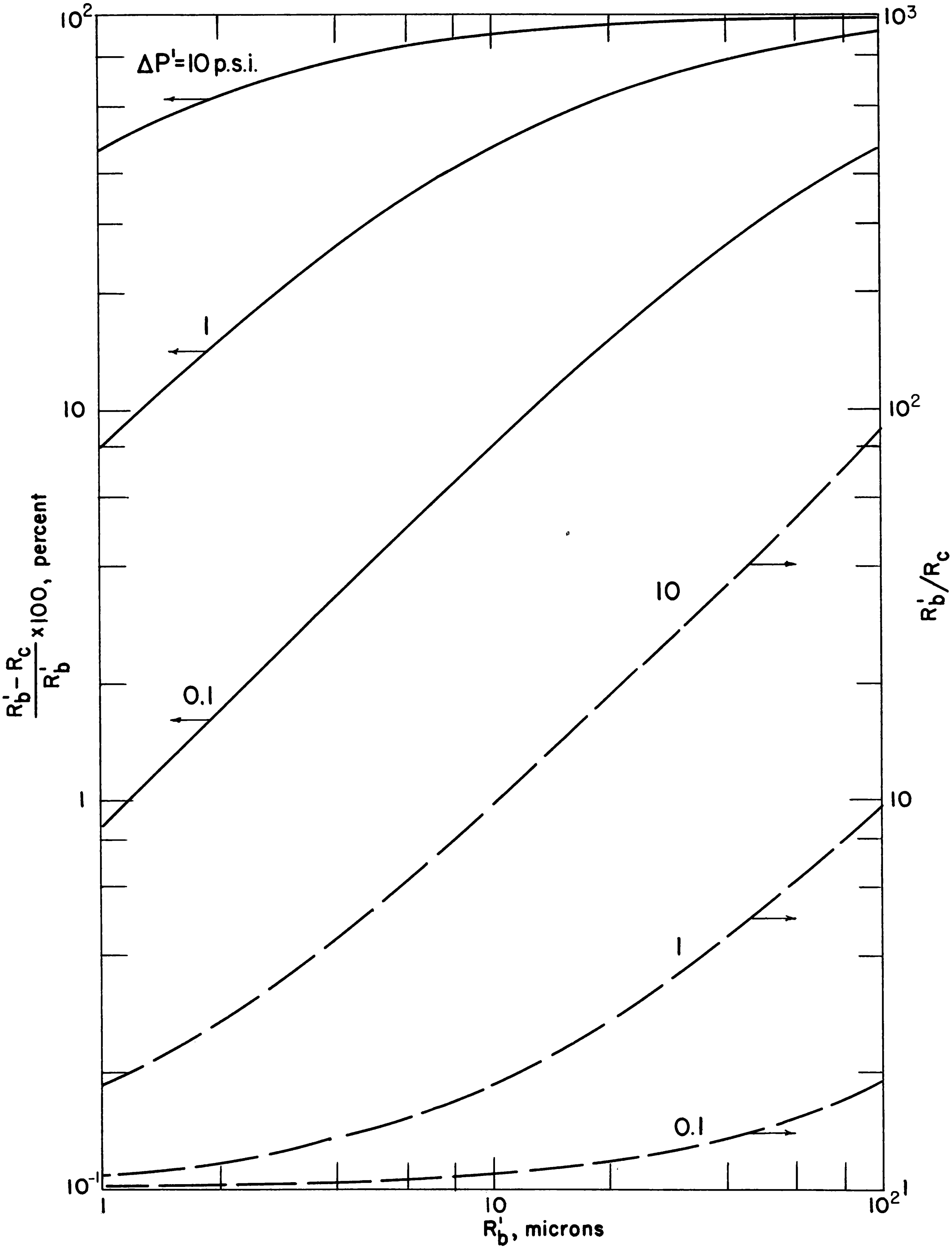

FIGURE 28. - Curves Showing How Pressure Gradient and Bubble Size Determine the Size of Pores the Bubbles Will Enter.

that, within limits, a given volume of foam liquid can be expanded into a foam of any desired volume by dispersing in it the required volume of gas. It is also readily apparent that characteristics of a foam of given expansion factor will vary according to the degree to which the gas is broken up into foam bubbles. The greater the degree of dispersion, the greater the surface area of the foam films, hence, the thinner the films will become.

The foregoing discussion establishes the fact that any method for measuring the viscous nature of foams should provide a means for controlling or following changes in expansion factor and texture. It must be noted that as drainage takes place, expansion factor may remain constant or may increase or decrease. When a bubble collapses, the liquid from that bubble is contributed to the liquid in the remaining bubbles. Thus, if the rate at which liquid is released by bubble attrition is greater than, equal to, or less than the drainage rate, foam density will increase, remain constant or decrease, respectively. The former trend is typical of an unstable foam; the latter, of a stable one.

Because foam is non-Newtonian its viscosity is a fictitious property that can be characterized in terms of its apparent viscous behavior relative to that of a Newtonian fluid subjected to the same flow conditions. The apparent viscosity of foam decreases as the rate of shear increases (18, 43). On the other hand, foams subjected to shear stresses below some critical value act as plastic solids. Under these conditions "plug flow" of foam may be observed in capillary tubes and small pipes wherein all the shearing action takes place at the flow boundaries (4, pp. 123-130). Depending on the expansion factor and the bubble sizes, the foam will move as a solid plug, exhibiting no measurable shearing within the foam body. In the porous system, shearing between bubbles, that is, within the filaments of foam, cannot take place except in pores and channels of at least twice the diameter of the average bubbble diameter. Moreover, the rates of movement in reservoir rocks, and particularly in pools containing high-viscosity crude oils, may not approach the critical shearing stress except perhaps in large channels in the vicinity of well bores. Thus, it may be surmised that the foam movement in oil reservoirs will be characterized by "plug flow" wherein all shear takes place at the flow-channel boundaries. If this is the case, the resistance to flow along any given length of flow channel will be proportional to the surface area of contact between channel walls and the foam bubbles and therefore proportional to the effective diameter of the channel. Insofar as viscous forces are concerned, the larger the channel (within limits), the greater the resistance to flow--a phenomenon diametrically opposite to that for Newtonian fluids in laminar flow.

In the following discussion it is assumed that the oil and water saturations at the entry face of water-wet oil sand which has previously been flushed by water and gas are such that gas injected at the face will flow through the porous medium with practically no movement of either of the liquid phases. Thus, if a mass of foam of uniform-size bubbles of radius R_b' is brought into contact with the sand entry face the differential pressure required to move the bubbles into any gas-filled pore opening of radius R_c is nearly

$$\Delta P = 4\gamma \left(\frac{1}{R_b'} - \frac{1}{R_c}\right). \tag{8}$$

R_b' is the radius of the trailing surface of the bubble at the time the constriction is penetrated and is related to the original bubble radius R_b by equation (4).[11]

Conversely, if some pressure $\Delta P'$ is placed on the foam the bubbles will move into all pore openings larger than

$$R_c = \frac{R_b'}{1 - \frac{\Delta P'}{4\gamma} R_b'}. \tag{9}$$

Although the pressure $\Delta P'$ is qualitatively positive in the direction of flow, the direction of surface forces and curvatures in the derivation require that $\Delta P'$ is negative as used in the equation. The physical interpretation is that $\Delta P'$ is actually the force tending to push the meniscus back from a constriction it is trying to enter. Hence, it is the force which must be overcome by application of pressure in the positive direction. In equation (9), as $\Delta P'$ increases, the denominator of the member to the right of the equality sign becomes larger and R_c becomes smaller. It may thus be seen that at a given injection pressure the largest flow channels, those which contribute to the greatest proportion of the total gas flow, will be most easily invaded by the foam bubbles.

If the foam introduced at the sand face is polydisperse, that is, comprised of bubbles of various sizes, then at any given pressure on the foam in excess of that in the sand, bubbles will enter those channels which have pore-entry radii approximately equal to or larger than R_c given by equation (9). Table 2 shows the ratio of bubble radius, R_b', to minimum radius, R_c, of capillary openings that will be entered when the foam contains bubbles ranging in radius from 1 to 100 microns. The differences, in percent, between the radius of foam bubbles and the radius of the smallest pore they will enter under pressure $\Delta P'$, are also tabulated. For these examples the bubble surface tension, γ, was taken as 20 d./cm. and the excess pressure, $\Delta P'$, 0.001 to 10 p.s.i., as indicated. The plotted data in figure 28 reveal that under low injection pressures the minimum-size channels foam bubbles can enter are those only slightly smaller in radii than the individual bubble radii. However, note the increasing rate of change in the ratio $\frac{R_b'}{R_c}$ with rising pressure. A bubble of 4 micron radius can enter a pore only very slightly smaller when the pressure differential is 0.001 or 0.01 p.s.i. At 1 p.s.i. the same size bubble can enter capillary openings 25 percent smaller than its own dimension; at 10 p.s.i. a pore 77.5 percent smaller than the bubble can be penetrated by it. The significance of the effect of the two parameters, pressure and bubble size, may be more fully realized by comparing the range of values for R_c when $\Delta P'$ is 0.1 p.s.i., and those for R_c when $\Delta P'$ is 10 p.s.i. A polydisperse foam under low pressure will enter only the largest pore channels but as the pressure is raised the fraction of total pore openings permeated by a foam of the same bubble size distribution will rapidly approach unity.

[11] Note that the factor 2 in equation (6) now is 4 because each foam-bubble film has two gas-liquid surfaces on which surface tension acts.

TABLE 2. - Effect of pressure and bubble size in determining the size of pores enterable by foam bubbles

$\Delta P'$	-0.001 p.s.i.		-0.01 p.s.i.		-0.1 p.s.i.		-1.0 p.s.i.		-10 p.s.i.	
R_b' Microns	R_b'/R_c [1]	Difference, percent[2]	R_b'/R_c	Difference, percent	R_b'/R_c	Difference, percent	R_b'/R_c	Difference, percent	R_b'/R_c	Difference, percent
1	1.000086	0.009-	1.000863	0.086	1.008625	0.855	1.08625	7.940	1.8625	46.31
2	1.000173	.017	1.001725	.172	1.017250	1.696	1.1725	14.710	2.7250	63.30
4	1.000345	.034	1.003450	.344	1.034500	3.332	1.3450	25.651	4.450	77.53
8	1.000690	.069	1.006900	.685	1.06900	6.455	1.6900	40.828	7.900	87.34
10	1.000863	.086	1.008625	.855	1.08625	7.940	1.8625	46.309	9.625	89.61
20	1.001725	.172	1.017250	1.696	1.17250	14.712	2.7250	63.303	18.25	94.52
40	1.003450	.344	1.034500	3.332	1.34500	25.651	4.450	77.524	35.50	97.18
80	1.006900	.685	1.069000	6.455	1.6900	40.828	7.900	87.342	70.00	98.57
100	1.008625	.855	1.086250	7.940	1.8625	46.309	9.625	89.610	87.25	98.85

[1] $$\frac{R_b'}{R_c} = 1 - \frac{\Delta P'}{4\gamma} R_b'$$

where R_b' = radius of upstream surface of bubble under given $\Delta P'$; R_c = pore entry radius; γ = interfacial tension--20 dynes per centimeter in this example. (Units must be consistent, that is, R_b', R_c, centimeters; $\Delta P'$, dynes per square centimeter; γ, dynes per centimeter.)

[2] Difference, percent $= \frac{R_b' - R_c}{R_b'} \times 100$

The compressibility of foam influences the behavior of foam at the entry face of the sand. To inject a foam into a porous system, the bulk foam must be brought to the sand face under a pressure adequate to cause its influx. As the pressure on the foam is increased, its ability to move into smaller and smaller pore openings is enhanced by the compression of the bubbles to smaller sizes. Hence, when a foam containing bubbles of radii in the range 10 to 200 microns at atmospheric pressure is compressed by an imposed pressure of 2 atmospheres, the bubble radii are reduced to the approximate range from 8 to 160 microns. At 10 atmospheres the range would be reduced to from 4.6 to 34 microns. With a 10 p.s.i. pressure gradient between the foam and the porous system, a foam of this bubble-size range would enter all pore openings larger than 1 micron in radius, as shown by table 2. Studies have shown that equivalent pore entry radii in oil reservoir sands range from approximately 20 microns to less than 1 micron (6, 20). However, in many coarse highly permeable and poorly cemented sands such as those found in a number of California reservoirs, the frequency of occurrence of pore radii in the less-than-2-micron range is relatively low. Assuming the smaller channels are impenetrable, they not only represent a small proportion of the void volume open to fluid flow, but also a small fraction of the total void space available to residual fluids. In strongly water-wet sands, most of the small channels probably contain aqueous fluid.

Clark and Blackman (8) showed that owing to the differences in the internal pressure of various size bubbles, gas will diffuse from the smaller to the larger. Thus, with time the small bubbles tend to decrease while the larger ones grow in volume. In addition, compressing a foam shifts the equilibrium saturation of the gas in the foam liquid. To restore equilibrium some of the dispersed gas must pass into solution in the liquid and in so doing further decreases the average size of the foam bubbles. It may be observed that during injection of a foam the several simultaneously occurring changes tend to permit some of the gas globules to move more readily as they decrease in size relative to the pores through which they are passing. However, as other gas globules increase in volume they do not necessarily increase in radius. When, for example, a spherical bubble initially 20 microns in diameter enters a straight capillary 10 microns in diameter, the bubble becomes a cylinder of 10 microns diameter and about 53 microns long. An increase in volume merely elongates the bubble. In a real porous system, bubbles may occur wholly in a single channel enlargement or may extend into several adjacent pore enlargements.

A large bubble moving through a small constriction may be divided into smaller bubbles. When the pressure differential between the portion of the bubble upstream of the constriction and that downstream exceeds the cohesive forces of the bubble walls within the constriction, the two parts will separate. Turbulence and gravity effects aid this division. Thus, foam moving through the sand can be regenerated into finer bubbles. Such occurrences may at least partially counteract the coarsening effect of coalescence of bubbles as well as enlargement by the diffusion of gas from smaller to larger bubbles.

In the foregoing analysis it was shown that a polydisperse foam could be introduced into a porous medium under certain conditions of pressure according to the size distribution of bubbles relative to that of the void spaces. The required conditions are attainable in the region immediately adjacent to the sand entry face. The question remaining concerns the movement of a bank of foam through distances of hundreds of feet between wells. The preceding paragraphs indicated that for initial entry into the pore openings pressure differentials as high as 10 p.s.i. may be required across single bubbles measuring only a few microns in length. In terms of conventional flow this would be equivalent to gradients of the order of 10^4 or 10^5 p.s.i. per foot--far greater than any gradients practicably attainable under conventional-flow conditions in oil reservoirs.

However, there is considerable difference between injecting bulk foam from the free space in a well bore into the confinement of a porous system, and moving the foam through the vast network of communicating channels of various shapes and sizes. Once they have gained entry the bubbles can reside in the porous structure in an extremely large variety of configurations: A single small bubble in a relatively large pore, a cluster of bubbles occupying a pore channel, or a single large bubble extending into several pore spaces. The possible orientations and configurations are almost innumerable. It was shown previously (see table 2) that even at low pressure gradients the small bubbles, those having diameters in the range of the smallest pore openings, could move with relative ease through a large percentage of the pore constrictions in the sand. The larger foam particles may protrude into a number of adjacent pore spaces of various sizes. The radius of the upstream surface of the bubble may be larger than, smaller than, or of the same size as the downstream surface. In any case, there usually are a number of alternate routes through which the bubble may move. It is only necessary that the required pressure differential between two openings be in proper relation to their relative sizes, as prescribed by equation (9). Statistically, there should be as many points at which expulsive forces tend to move the upstream surfaces of bubbles forward out of constrictions as there are points at which deterring forces tend to restrict the forward movement of bubbles into constrictions at their downstream surfaces. Since these two opposing forces tend to balance each other, only a nominal imposed pressure gradient should be required to move a bank of foam bubbles forward.

Consider a capillary channel across which a film of wetting liquid has been established. If the film is not moving or if it is moving under steady-state conditions and interfacial forces are acting uniformly on both sides of the film, the film has zero curvature. Similarly, two bubbles of equal diameter in contact with each other will have a planar septum dividing them, that is, the curvature, $\frac{1}{R_c}$, of the septum equals zero. If the radius of one bubble is R_1, and that of the other is R_2, the radius of curvature, R_s, of the lamella between the two bubbles is that produced by the resultant of the pressures across the interface of contact, that is,

$$\Delta P_c = \frac{4\gamma}{R_1} - \frac{4\gamma}{R_2} = \frac{4\gamma}{R_s}\ . \tag{10}$$

Solving for R_s

$$R_s = \frac{R_1 R_2}{R_2 - R_1} \ . \tag{11}$$

This relationship reveals (4, pp. 22-23) that the curvature $\frac{1}{R_s}$ can vary only between zero, when $R_1 = R_2$, and $\frac{1}{R_2}$, when $R_2 = 2R_1$ (no deformation of the larger bubble by the smaller).

The fact that foam bubbles which have approximately the same radius of curvature when separate, have a greatly increased radius of curvature at the interface of contact when they are joined, leads to a significant observation. As previously indicated, to move a single bubble through a pore constriction requires a certain minimum differential between the pressure immediately upstream of the trailing bubble surface and that immediately downstream of the bubble surface at the pore constriction. If two such bubbles are in tandem they do not act as two separate bubbles because the contact between them is not a point contact of two spherical surfaces but a flattened interface common to both bubbles. In the joining of the two, a gas-liquid surface is eliminated thereby reducing the total surface energy and requiring an equal amount of work to separate the two spheres again. The forward and rearward surfaces remain the same, as though two separate bubbles were in the space occupied by the tandem unit. Thus, to move the dual-bubble through the pore constriction requires the same differential pressure as before. But now the differential is imposed across a length perhaps twice that for the single bubble and the pressure gradient is thereby halved. Similarly, a string of bubbles joined in the same manner as described for the two-bubble unit and extending over perhaps the entire length of the foam bank should require a greatly, but certainly not proportionately, reduced pressure gradient to move it through the porous system, while the required total pressure drop will be of the same order of magnitude as for the single bubble. This highly over-simplified picture does not take into consideration the pressure gradient required to overcome viscous resistance of the foam filament and to move it at a particular rate along the flow path.

Displacement of Oil by Foam

The injection of foam into the sand immediately adjoining a well bore establishes a "foam bank." Initially, foam particles, or aggregates, disperse through the large pore channels, presumably those which have been previously flushed of most of their oil content. The resistance to flow increases rapidly owing to the high effective viscosity of the foam and to the blocking tendencies of constrictions along the flow paths. As flow resistance builds up, and injection pressure is increased, the smaller bubbles are forced into the smaller channels thereby causing a foam bank to be developed. Owing to greater resistance to flow at the injection well relative to the resistance to flow in the downstream region of the reservoir, the pressure in the latter region is reduced and a higher pressure gradient is developed across the foam front. With establishment of a mobile foam bank, flow paths that had previously carried the greatest part of the total flow of the prior displacing medium become blocked or restricted resulting in the following conditions favoring displacement of oil and water: (1) Diversion of flow to the small unflushed flow channels, (2) migration of a medium exhibiting high effective viscosity, and (3) presence of a sharp pressure gradient at the invading front. Scavenging of the residual oil by the foam causes an oil bank or zone of high oil saturation to form ahead of the foam front.

It is assumed a mobile foam bank of approximately optimum thickness has been established.[12] Further injection of foam is terminated and gas is injected into the sand. The injected gas flows through small communicating capillaries which foam has not entered and the channels through which the propulsion of foam in the foam bank takes place. Because the finer capillaries will most likely contain water and perhaps some oil, it is apparent that gas can enter small capillaries only if the required displacement pressure is reached.

As gas is injected, it forces liquid and foam ahead of it. The oil-displacement mechanism previously described continues to develop the oil bank at the upstream front. Considering the complexity of the porous system and the physical obstacles presented to the foam as it moves through the sand, it is reasonable to assume that many of the bubbles will be left behind as the foam bank progresses. Other factors tend to dissipate or destroy the foam bank: (1) The radial outward movement reduces its thickness; (2) the coalescence of bubbles and the diffusion of gas between bubbles reduce the number of bubbles and hence the number of gas-liquid interfaces; and (3) adsorption of the surface-active substances from the foam liquid to the solid surfaces, or diffusion into the interstitial brines, depletes the bubble walls of foam-forming material.

Conversely, movement of the foam may result in its redivision into smaller bubbles as it passes through the tortuous paths and constrictions. Moreover, as the foam and its associated liquid move to regions of lower reservoir pressure, expansion of small bubbles and formation of new bubbles, as gas comes out of solution in the liquid, tend to counteract the attrition of the foam bank. In addition, liquids containing some of the surface-active foam chemicals will tend to be pulled by capillarity into constrictions so that as gas passes through them new bubbles will be formed. In short, there will be two simultaneous processes occurring, one tending to destroy the foam, the other acting to renew or regenerate the foam in the formation. The latter action not only aids persistence of the foam bank as it moves toward the producing well but also acts to renew foam in channels in which gas might tend to break through.

As the foam bank moves radially outward from the point of injection it must eventually become so thinly dispersed as to lose those properties beneficial to oil displacement. It may be possible to augment the foam bank by

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[12] Presumably, for each porous system there is an optimum thickness of foam bank. At present, neither a fundamental nor empirical method is known for predicting the optimum foam bank dimension.

injecting slugs of foam liquid from time to time during the gas injection phase of the drive. The liquid, owing to the relatively high water permeability of the sand, would tend to overtake, and through in-place generation of foam, supplement the foam bank.

Lacking fundamental relationships that describe the time rate of flow of a heterogeneous dispersed phase (foam) in a porous system, it is not possible to determine quantitatively the effect of foam on areal sweep efficiency. It was stated earlier that high sweep efficiency has been correlated with low mobility ratio. Presence of foam certainly has the same effect as a decrease in the mobility of the fluids in the invaded regions of the sand and yet does not alter the mobility of the fluids in the unswept portions ahead of the foam bank. The effect is an apparent decrease in mobility ratio. On this basis it may be surmised that fluids in unswept portions of the unit patterns formed by injection and producing wells, may move downstream under the influence of existing pressure gradients, while the flow of injected gas through previously flushed areas is restrained by the foam bank.

APPENDIX II. - Chemical identification of surface-active agents used in foam experiments

Trade name	Manufacturer	Chemical name	Type
Aerosol C-61.......	American Cyanamid Co.	Ethanolated alkyl guanidine-amine complex	Cationic
Aerosol OS.........	do.	Isopropyl naphthalene sodium sulfonate	Anionic
Aerosol OT.........	do.	Dioctyl sodium sulfosuccinate	Do.
Arquad 2C..........	Armour and Co.	Dicoco dimethyl ammonium chloride	Cationic
Arquad T...........	do.	Tallow trimethyl ammonium chloride	Do.
Drench EP-3........	National Foam Systems, Inc.	Unknown	Unknown
Duponol EP.........	E. I. du Pont de Nemours and Co., Inc.	Fatty alcohol alkylolamine sulfate	Anionic
Duponol RA.........	do.	Modified ether alcohol sulfate sodium salt	Do.
Duponol WAQ........	do.	Sodium lauryl alcohol sulfate	Do.
Ethomid HT-60......	Armour and Co.	Condensation of hydrogenated tallow amide and ethylene oxide	Nonionic
Hyonic FA-75.......	Nopco Chemical Co.	Modified fatty alkylolamide	Do.
Miranol HM Concentrate.......	Miranol Chem. Co., Inc.	Ethylene cyclomido 1-lauryl, 2-hydroxy ethylene Na alcoholate, methylene Na carboxylate	Amphoteric
Miranol MM Concentrate.......	do.	Same as Miranol HM except myristyl group is substituted for lauryl group	Amphoteric
Nacconal NR........	National Aniline Div., Allied Chem. and Dye Corp.	Alkyl aryl sulfonate	Anionic
Ninol AA62.........	Ninol Laboratories, Inc.	Lauric diethanolamide	Nonionic
Ninol 1001.........	do.	Fatty acid alkanolamide	Do.
Petrowet R.........	E. I. du Pont de Nemours and Co., Inc.	Sodium alkyl sulfonate	Anionic
Pluronic L44.......	Wyandotte Chem. Corp.	Condensation product of ethylene oxide with propylene glycol	Nonionic
Product BCO........	E. I. du Pont de Nemours and Co., Inc.	C-cetyl betaine	Amphoteric
Renex 650..........	Atlas Powder Co.	Polyoxyethylene alkyl aryl ether	Nonionic
Sorbit AC..........	Geigy Chemical Corp.	Sodium alkyl naphthalene sulfonate	Anionic
Sulfanole FAF......	Warwick Chem. Co., Div. Sun Chem. Corp.	Sodium salt of fatty alcohols, sulfated	Do.
Triton AS-30.......	Rohm and Haas Co.	Sodium lauryl sulfate	Do.
Triton X-100.......	do.	Alkyl aryl polyether alcohol	Nonionic

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