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FOAMS IN POROUS MEDIA—SUPRI TR-49

Topical Report

By
S. S. Marsden

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1. INTRODUCTION

In 1978 a literature search on selective blocking of fluid flow in porous media was done by Professor S.S. Marsden and two of his graduate students, Tom Elson and Kern Guppy. This was presented as SUPRI Report No. TR-3 entitled "Literature Preview of the Selected Blockage of Fluids in Thermal Recovery Projects."

Since then a lot of research on foam in porous media has been done on the SUPRI project and a great deal of new information has appeared in the literature. Therefore we believed that a new, up-to-date search should be done on foam alone, one which would be helpful to our students and perhaps of interest to others. This has been based on references which were known to the author and supplemented by those in the MS Research Report of Bret Beckner and the drafts of the PhD dissertations of Syed Mahmood and Fred Wang. However, the interpretation and presentation of the material is the sole responsibility of the author.

For various reasons, almost every literature search misses some papers, patents, theses, dissertations, government reports, etc. If the readers of this search know of any such publications, the author would like to hear about them. If the readers find any errors or disagree with the views expressed, the author would also appreciate learning about these.

As can be seen, this is a chronological survey showing the development of foam flow, blockage and use in porous media, starting with laboratory studies and eventually getting into field tests and demonstrations. It is arbitrarily divided into five-year time periods.

2. PIONEER WORK

It is difficult to establish from information in the open literature as to which of two laboratories started this foam research. The first publication of any direct importance was a patent awarded to Bond and Holbrook (1958) but the author of this report was able to observe the essentially complete work of Fried in late 1956. Unfortunately, Fried's original report had an unusually long gestation time in the review process and was not actually published until 1961 in greatly abbreviated form.

Bond and Holbrook (1958) suggested that foam could be generated in an oil reservoir by consecutive injection of aqueous surfactant solution and gas. They considered foam as a displacing medium for oil which would be less mobile than air and therefore have a more favorable mobility ratio relative to oil. It was claimed that sweep efficiency for both miscible and immiscible gas drives would thereby be increased.

Fried's report included theoretical and laboratory work on the flow of foam in both tubes and porous media. This was all relative to what he called a *foam drive*, secondary oil-recovery process. For this, foam would be generated by bubbling a gas, such as air, N_2 or CH_4, through a surfactant solution and then used to displace oil from a porous medium. In his laboratory work on unconsolidated porous media, the oil recovery, particularly for viscous oil, was much better than that obtained on the same or similar sand packs by gas drive, water flooding or surfactant solution flooding.

Besides oil displacement tests, Fried made a number of interesting measurements on the physical properties of foam. Apparent viscosity was measured in both rotational and tube-type viscometers; and while the treatment of the experimental data leaves a great deal to be desired by current standards, the highly viscous nature of the foam was apparent. He was the first to measure the streaming potential or electrokinetic nature of foam, and he found that this could lead to complete fluid blockage unless it was suppressed with electrolyte in the foamer solution. Unfortunately, Fried left the U.S. Bureau of Mines at about the time the work was reported and it was not continued by others there.

3. THE EARLY 1960'S

To substantiate the patent of Bond and Holbrook, Bernard carried out experimental work on the generation of foam in porous media and reported this in early 1963. He used an unconsolidated sand having a range of grain sizes giving a permeability of about 6 darcies ($6 \times 10^{-12}\ m^2$). Surfactant solution was either present prior to injection or injected as a batch just before initiation of gas drive. Either water or a blend of refined oils or both were the original fluids.

Because theory did not exist to predict what foaming agents would be best, a purely empirical approach was used. Preliminary screening was done in equipment similar to that used to evaluate surfactants for removal of liquids from gas wells. As was expected, the commercial foamers worked best when only water was the liquid, and worse when oil was the only liquid, with the performance being intermediate when both were present. Unfortunately, the foamers were only identified by letters and not their chemical formulas.

Various flooding tests were carried out with different combinations of initially saturating and displacing fluids as well as different surfactants. The results of these did not always agree with those of the screening tests as far as the surfactants were concerned. Bernard concluded that the best surfactants would be those that would form foam in both the oil and the water within porous media during immiscible displacement. For miscible displacement with the LPG-gas process, foamers that worked best in water alone were to be preferred.

In an MS thesis Bennett (1963) described laboratory experimental work on the use of foam generated within porous media to displace water in an aquifer in which natural gas storage was going to be initiated. He felt that a gas buffer between the injected surfactant solution and the connate brine increased displacement efficiency, the lack of which may have led to interaction between the electrolyte of the brine and the surfactant itself. In a continuation of this work, Kolb (1964) started with his consolidated porous medium completely saturated with a surfactant solution and reported that liquid recovery increased with surfactant slug size and concentration. Foamability of the surfactant was of primary importance while foam stability and static surface tension were secondary. His results indicated that ultimate gas storage volume in an aquifer could be increased by injecting surfactant solution before gas injection started. In parallel work done by Deming (1964) at the same institution, he reiterated the latter points and also reported that an increase of the surface elasticity of the surfactant solution led to a decrease in the displacement efficiency of the solution.

In the last of this series of theses, Iden (1965) noted that similar efficiency of displacement could be brought about by a small volume of a highly effective surfactant solution or a large volume of a less effective one. He also found that foam stability became an important factor when flow rate was slow.

In 1963 a patent was awarded which dealt with foam generated within the reservoir. Beeson found that the injection of a surfactant followed by a gas-driven solvent bank led to EOR. Although he attributed this to a change from a water-wet to an oil-wet state, it is likely that foam generation made a more significant contribution than did any wettability change.

At the end of 1963 Emery patented a modification of the *in situ* combustion process wherein a surfactant is to be injected in the water bank preceding the combustion zone. He claimed this would lower the oil-water interfacial tension and thereby increase the efficiency of oil displacement by the water bank. While this is probably true, a more important effect (which he did not mention) would be the formation of foam with the N_2 remaining from the injected air after the 0_2 had been consumed. From what we have learned later on (c.f. below), this would selectively decrease the permeability of the more permeable strata relative to the less permeable and hence improve the vertical profile of the fluid front.

A very extensive laboratory study was carried out by Bernard and Holm (1964) on the effect of foam on permeability of porous media to gas. Both consolidated and unconsolidated ones ranging from 100 to 146,000 md (0.1 to 146×10^{-12} m^2) had gas permeabilities less than 1% of the specific permeability when foam was present. The decrease was found to be much greater for loose sands than tight ones, which suggested the use as a selective plugging medium for high permeability channels in various oil displacement processes.

The adverse effect of oil on many foaming agents was reported again but it was noted that some were still effective even in the presence of oil. Continuous injection of foams helped to maintain the foam when oil was present. Permeability reduction increased with foam concentration, but concentrations as low as 0.01% were still effective.

Stable foams in porous media over long periods of time could be obtained if foam solution was added periodically. The stability increased as the specific permeability of the porous media decreased.

In a complementary paper to the one discussed above to water, Bernard *et al.* (1965) described the effect of foam on the aqueous permeabilty of porous media having trapped gas saturation. Interestingly enough, they found that the aqueous permeability at a given saturation was the same whether or not foam was present. In effect, foam decreases the permeabilty to water by causing a higher trapped gas saturation to be reached than when foam is absent. Increasing the foam concentration increases the trapped gas concentration even further.

Two other interesting observations were reported here. Foam was found to persist in porous media even after 10 to 25 pore volumes of surfactant-free water was passed through the porous media. In at least two cases it was also found to persist at temperatures up to 140°F (60°C) for as much as ten days.

The use of externally generated aqueous foam to displace oil from unconsolidated and consolidated sands was also patented by Craig and Lummus (1965). In the preferred form of their invention, they recommended that 0.1 to 10% pore volume of an oil-miscible solvent such as LPG be injected first and that this be followed by gas (natural gas, N_2, H_2, CO_2 and CO) equal in volume to 50 to 100% of the solvent. Next, at least 20% pore volume of externally generated foam is injected and this may in turn be driven by water. They claimed that more oil was recovered by externally generated foam than that generated within the core.

The selective blocking of gas flow by foam led to another proposed application by Holbrook and Bernard (1965). They suggested that preferably an oleic or possibly an aqueous solution of surfactant be injected into a formation producing at a high GOR. When the production is resumed, the flowing gas generates foam in the gas-producing strata and impedes further gas flow. They also proposed that use of aqueous surfactant solutions in this manner would cut down coning when natural gas was stored in aquifers.

Although a good deal of experimental work had been done in the flow of foam in porous media by the mid-1960's, the interpretation was based on external measurements of such parameters as pressure drop and flow rate with little or no direct knowledge of what was going on within the pores. As had been done in much earlier work on oil and water flow in porous media, we undertook some microscopic studies of foam flow in thin gas cells packed with glass beads. These were published in an obscure report by Sharma (1965) and will be summarized only briefly here.

He found that the size and extent of the bubbles depended mainly upon the type and concentration of the surfactant as well as the foam quality. With one surfactant at low concentration (0.1% Aerosol MA), small bubbles moved through certain channels at low pressure differentials but at higher pressure differentials, a body of foam made up of bubbles of about the same size moved as a foam bank. Bubble size decreased with an increase in surfactant concentration and this was often manifest in membrane-like foam at low concentrations and small bubble foam at higher ones. Bubble size for another surfactant (Adfoam) also increased with quality.

Foams produced from a generator made up of unconsolidated sand was uniform in size when viewed in a thin empty cell but became heterogeneous when flowing through a packed cell. Some small bubbles became immobile by adhering to glass bead surfaces as if the latter had become oil-wet.

Foam displaced oil in a thin, packed bead cell at low rates in a piston-like manner; but at higher rates there was significant fingering, and at still higher rates foam bubbles became dispersed in the oil itself. With foam breakthrough a frothy emulsion was first produced followed by foam alone. Hence the displacement mechanism and sequence is far more complex than is usually visualized.

4. THE LATTER 1960'S

After reviewing earlier work on foam flow, stability and persistency in porous media, Bond and Bernard (1966) presented results on the effect of sand wettability on foam flow. Their data was difficult to interpret. One problem may have been that the silicones usually used to make the sand surfaces oil-wet are some of the best foam breakers known to man and so the systems which were intended to be oil-wet were simply foam-breaking systems. In other experiments they noted the general relationships between bubble size, pore size, pressure gradients and foamer concentration but no numerical results were presented.

Two studies on foam flow in short, unconsolidated porous media were published in 1966, the first by Marsden and Khan and the second by Abernathy and Eerligh. In both cases externally generated foam of a range of qualities was injected, flow rate and pressure drop measured and liquid saturation determined within the porous medium by electrical conductivity. Marsden and Khan also measured the apparent viscosity, μ_a, of the foam with a modified Fann VG meter and a high shear rate instrument (based on the vibrating reed method) known as the Bendix Ultraviscoson. For the former μ_a decreased with increasing shear rate but usually fell within the range of 50 to 500 cp (50 to 500 mPa $\cdot\, s$), and at a given shear rate it increased almost linearly with quality. For the latter instrument, kinematic μ_a was independent of quality but absolute μ_a increased with quality from about 3 to 8 cp (3 to 8 $mPa \cdot s$).

From the flow rate and pressure drop data, it is possible to calculate an effective permeability-apparent viscosity ratio, k_e/μ_a. This decreased almost linearly with quality for high permeability porous media, but the rate of decrease was less for tighter ones. An attempt was made to normalize the data for several porous media by calculating a relative permeability to apparent viscosity ratio, k_r/μ_a and plotting this against quality; while this brought the data closer together, it was not entirely successful. The k_r/μ_a ratio increased with surfactant concentration and with liquid saturation in the porous media. Estimates for μ_a of foam in these porous media ranged from 30 to 100 cp.

Abernathy and Eerligh (1966) carried out a number of measurements on externally generated foam made with five different surfactants at three different concentrations. This flowed through four short porous media in series which were packed with graded Ottawa sand having mesh sizes from 20/30 for the first to 80 for the fourth. These porous media were separated by optical cells fitted with a light source and detector for measuring attenuation by scattering at the liquid-gas interfaces. Pressure drop across each porous medium could be measured as well as electrical conductivity. Flow rate was determined by the time required to fill a horizontal burette and quality by its weight empty and filled. Bubble size was measured with an especially constructed thin cell viewed under a microscope.

With two exceptions traced to equipment malfunction, they found a decrease in foam mobility with increase in foam quality. For qualities below 80%, bubble size as indicated by transmitted light did not change appreciably; but above this, bubble size increased with quality. The magnitude depended on the surfactant, but the rate of increase was about the same for all. As measured by the same instrumentation, bubble size decreased with increasing surfactant concentration. With one exception, these foams showed an almost exponential increase in mobility with decrease in bubble size. There was a drastic increase in mobility when the bubble size became smaller than the pore opening estimated from capillary pressure data.

While some authors recommended that preformed foam be injected from the well into the reservoir rock and others thought that the constituents should be injected so that the foam could be generated *in-situ*, Hardy and McArthur (1966) patented still a third method which they felt was superior because it produced the foam out in the reservoir away from the injection wells. To accomplish this, an aqueous solution of both the foaming agent and a soluble gas were to be injected into the formation at a pressure above the bubble point. When the gas came out of solution at the lower pressures out in the reservoir, foam was generated. This method had the advantage that it allowed a low viscosity solution to be pumped under high pressure gradients near the well while the higher viscosity foam was subjected to lower pressure gradients, and hence lower shear stress out away from the well. In one modification of their invention, they suggested using LPG as the solvent.

A common method of storing natural gas in geographical areas close to markets is to inject the gas in underground porous rock formations such as either aquifers or else abandoned oil or gas fields. Many times these have leaks through fractures in the cap-rock or through improperly abandoned or completed wells. Injection of aqueous foam solutions in porous formations overlying the cap-rock was recommended as a remedy for this by O'Brien (1967). Any leaking gas would, of course, generate foam *in situ* and hence impede or block the flow of additional gas. Improved performance was claimed if a viscosity increasing agent was added to the foam solution and if it was previously saturated with CO_2. A list of suitable commercial foaming agents giving both their trade names and their approximate chemical names was also included in this patent.

Various workers received patents in 1967 which dealt either directly or indirectly with foam generation in reservoirs. Santourian (1967) described the injection of hot aqueous solutions of gas followed by flood waters containing such thickening agents as CMC, CEC, Dextran or Polyox. The latter have some surface activity and so foam may well have been produced and made a significant contribution to the process. O'Brien and Sayre (1967), Zwicky (1967), and Rai and Bernard (1967) as well as others have mentioned the possibility of wettability changes brought about by the foaming agents, but could not even agree on the direction of change of wettability. The latter authors claimed that successive banks of foam made with anionic and cationic agents produced more oil than either alone, but thought this might also be due to the formation of different kinds of emulsions (O/W or W/O).

The first patent on use of foam in the CO_2 injection was awarded to Bernard and Holm (1967). It also included use of ethane and propane. A long list of suitable surfactants was also included in the patent.

The physical properties of foam and their applications in petroleum operations were reviewed for the Seventh World Petroleum Congress by Marsden *et al.* (1967). Some of the experimental results of Abernathy and Eerligh (1966) on the flow of foam through porous media were included in this paper.

Because of the extremely efficient blocking action of foam in porous media, Bond and Bernard (1967) were concerned that formation of foam in the porous rock adjacent to an injection well would prevent further injection of fluids if foam generation took place too quickly. Therefore, they patented the injection of a water buffer following the surfactant solution and preceding the gas injection to prevent this. They also included in their patent the injection of a sequence of many slugs of surfactant solution, water and gas throughout the project.

Another patent on use of foam in underground storage of natural gas was awarded to Bernard (1967). Besides reiterating the claims of O'Brien's (noted above), it is suggested that an envelope of foam formed from carbonated foamer solution increased the gas storage space in an aquifer by confining the gas within a limited space. He also recommended the use of brine instead of fresh water in preparing the foamer solution to prevent blockage from clay swelling.

While it does not apply directly to foam flow in porous media, the work of Raza and Marsden (1967) on foam flow in small glass tubes (radius 0.25 to 1.5 mm) does have some bearing on this subject. The bubble sizes were much smaller than the tube sizes and so these authors assumed the foam was a continuum and treated their data in terms of a power law fluid. At low shear rates, the flow behavior index was unity and so the foam behaved like a Newtonian fluid. The apparent viscosities* increased with foam quality and cover the range from 15 cp to 266 poise (15×10^{-3} to 26.6 $Pa \cdot s$).

At higher shear rates these foams had flow behavior indices ranging from about 0.3 to 0.5 and hence they behaved like pseudoplastic fluids. Thus the foam went from a laminar type flow to a semi- plug-like type of flow, the extent of which increased with both foam quality and tube radius.

This paper also includes results on measurement of the streaming potential of foam in both tubes and unconsolidated porous media. An equation was derived which related this to the pressure drop, the tube dimensions, the zeta potential and the dielectric constant, as well as the consistency index, flow behavior index and density of the foam.

*The term *apparent* is used here because there was an unexplained effect of tube radius on the results. This may have been due to foam slippage at or near the tube wall. Unfortunately, a correction was not made for this.

The displacement of Newtonian fluids of different viscosities by foam in Hele-Shaw models was studied by Moser (1967). He used aerosol shaving foam injected by a small syringe pump, varied injection flow rate, measured injection pressure and traced the displacement front. In checking the equipment with viscous oils displacing water, he found the pressure buildups with swept-out area similar to those for foam displacing water, although in most of his runs foam displaced glycerin. Sweep efficiency was less in the lower permeability models as was foam apparent viscosity. Sweep efficiency was higher at lower mobility of the displaced fluid compared to a Newtonian fluid of the same viscosity. Pressure difference from the beginning of displacement to foam breakthrough was essentially independent of injection rate.

During oil production from gas-cap reservoirs, the gas tends to migrate downwards and come into the wells. Ferrell *et al.* (1968) recommended the injection of a foaming agent at or near the gas-oil contact to form foam with the gas. Mixing is achieved either by pumping a liquid into the oil zone and then forcing the foamer into the gas zone or else by producing from the oil zone and allowing the gas cap to expand. It was also claimed that this approach minimized encroachment of oil or flooding media into the gas cap during secondary recovery operations.

To cut down water coning Heuer (1968) recommended the injection of a foamer solution at or near the water-oil contact and then following this with gas to generate a foam barrier when the well is again on production. Limited laboratory work showed that foam did cut down gas flow while still allowing oil flow but the same was not demonstrated for water and oil flow. One field demonstrated a dramatic but temporary four-day decrease in GOR but then gas came in again strongly.

In a very important basic patent containing little experimental justification, Needham (1968) taught that foam made with steam as the gaseous phase be injected into a reservoir to get a better injection profile than wiih steam alone. When the steam condensed and the foam collapsed, the flow of hot liquids back into the well would not be impeded by the presence of a gaseous phase.

Up to this point in time, different theories had been developed to explain the flow of foam in porous media. Some held that foam could be treated as an almost homogeneous fluid flowing through essentially all of the pore system, while others believed that the gas and the foamer solution would move independently and flow through separate and different pore channels. Holm (1968) reported the results of a series of experiments which supported the latter viewpoint for flow under reservoir conditions. He felt that even with externally generated foam, the gas and liquid separated within the porous medium and then reformed as foam. The liquid moves through the porous medium in the form of the bubble films while the gas moves by breaking and reforming bubbles. The low liquid flow rate corresponds to the low liquid saturations in a foam-bearing porous medium and effective permeability may be calculated by Darcy's law. The gas flow rate deviates from that calculated by Darcy's law modified for more than one fluid present.

As we see it, the crux of the difference in the two viewpoints is that the several investigators are talking about different things but using the term *foam* to describe them. Holm says that, "...the foam bubbles (are) large (>0.1 mm)," but most consolidated reservoir rocks have pore diameters which are smaller than this by at least an order of magnitude. Hence these *bubbles* must have extended over and through at least several pores and his explanation appears to be reasonable for such large bubbles. Other work indicates that large bubbles are present both in higher quality, drier foams or when low concentrations of surfactants are used. But for lower quality, wetter foams or those made with higher concentrations of foaming agent, smaller bubbles would be produced and these could well flow through porous medias as an essentially homogeneous fluid. This is illustrated in the works described earlier by Marsden *et al.* (1967).

The flow properties of foam in porous media also interested workers in the USSR. Evgenev and Turnier (1969) carried out experiments on both unconsolidated sands. (3.1 *d* or $3.1 \times 10^{-12} m^2$) in large glass tubes (3.7 cm diameter x 60 cm long) and in flat cells containing large glass beads (2 mm diameter). They observed a threshold pressure and so described the foam as being a Bingham plastic. But they also found this threshold pressure dependent on the length of time the foam had been at rest in the porous medium and so they also described it as being thixotropic. In addition, cessation of flow took place at some finite pressure gradient smaller than the threshold gradient and hence there was a gradient smaller than the threshold gradient and hence there was a hysteresis loop which caused them to describe the foam as being a "pseudosolid." Some problems may have arisen in the terminology because of the difficulties of translation of the paper to English.

In enriched gas drives, more of the injected gas often goes into the more permeable zones than is economically desirable. To cut down on this, Leach (1969) recommended that the gas be preceded by an aqueous solution of an oil-sensitive foaming agent. The enriched gas thus forms a foam which diverts gas into the low permeability zones. After a matter of some weeks, the foam would break because of its sensitivity to oil and this would allow a high injection of dry gas to drive the enriched gas through the formation.

The rheological work of Raza and Marsden (1967) describing the flow of foam through glass tubes was extended to ones of smaller diameter by David and Marsden (1969). In analyzing the data, corrections were made here for the very significant effects of fluid slippage at the tube wall and for the semi compressible nature of the foam. The uncorrected apparent viscosities changed with foam quality, but the corrected ones were independent of foam quality. However, the corrected apparent viscosities still increased with tube diameter, which is not to be expected.

The corrected apparent viscosities decreased, as before, with increasing shear stress, still indicating that the foam behaved like a pseudoplastic fluid, but one with a very low gel strength. The latter, as measured with a Stormer viscometer, increased slowly with quality, but were still an order of magnitude too small to affect the pseudoplastic flow behavior.

The bubble size frequency distribution was found to be asymmetrical, resembling a χ^2 distribution but it approached a normal distribution at high foam quality. The arithmetic mean bubble diameter was found to be proportional to quality. As expected, the bubble size changed with time with the larger ones growing and the smaller ones shrinking.

The need for temporary diverting agents in fracturing and acidizing jobs prompted the work described by Smith *et al.* (1969). They did laboratory work on two packed columns of different permeabilities (having a ratio of 20:1) mounted in parallel. Injection of foamer solution was followed by injection of N_2 in a series of repeated treatments. This method of selective blocking worked better than others in a fractured dolomite with high vertical permeability. They claimed the method could be used in wells with temperatures up to 250°F (121°C).

5. THE EARLY 1970'S

To increase the degree of plugging and the life of the foam, Raza (1970) felt the foaming solution should be divided into several smaller batches which would be injected alternatively with smaller batches of inert gas. To avoid plugging of the formation near the well, batches of spacer fluid such as water or brine could be injected between the gas and the foamer solution.

In early 1970 two papers appeared on the use of foam as a gas blocking agent with particular reference to underground storage of natural gas. In the first, Albrecht and Marsden (1970) described laboratory experiments on the flow of foam in unconsolidated sands and sandstones. They found that steady gas or foam flow could be established at some injection pressure p_b and then the pressure decreased until flow ceased at some blocking pressure p_b. When flow is again established at a second, higher p_i, blocking can again occur at another p_b that will usually be greater than the first p_i. The blocking pressure depends on the foamer and its concentration as well as its saturation and the kind of porous medium. Gas blockage appeared to be greater in unconsolidated porous media than in consolidated ones.

In the second of the two papers Bernard and Holm (1970) described laboratory work on a model gas storage reservoir. They found that foam was 99% successful in reducing leakage from the sandstone model. The amount of foaming agent required to seal a leak depended on the adsorption-desorption properties of the agent on the rock surface. Certain modified anionic esters of relatively low molecular weight were found to be superior to most nonionics. Methods of applying the foaming agent in the field are recommended in the paper.

Vertical leaking of fluids past cement jobs going through tar sands apparently occurs when heated fluids are pumped down the casing or tubing. Elkins (1970) suggested that a foamer solution be injected around the casing with a permanent gas (unless the leaking fluid was gas) to form a foam and thus eliminate the leakage.

In late 1970 Bernard was awarded what looks like a very general patent on the use of foam drive for oil recovery. Either foam or the ingredients of foam are to be injected to form a foam bank which is then to be driven toward the production wells by a combination of gaseous and aqueous liquid drive fluids. The latter should be in the ratio of 5 to 15 volumes of gas (reservoir temperature and pressure) per volume of liquid, i.e., the proportions that would give a relatively dry foam. A list of suitable, commercially available foaming agents is included here.

According to Dauben and Raza (1970), the stability of foam in earth formations against the adverse effects of oil and elevated temperatures was increased by dissolving water-soluble film-forming polymers in the foamer solutions. Polyvinyl alcohols and polyvinyl pyrrolidones worked well. Stability of the foams could be increased further by adding film plasticizers such as glycerin.

Up to the end of 1970 practically nothing had been published on field work with foam in porous media other than brief mention of short tests in several patents. At this time Holm (1970) described their use in injection tests in the Siggins field, a small shallow one in Illinois. Foamer solutions and compressed air were injected simultaneously and alternately in one well and production observed in five offset production wells. Concentration of foamer solution started at 0.1% and then was increased to 0.5% and eventually to 1%. The foam reduced the mobility of both water and gas to less than 50% of their original values. A more uniform injection profile was observed and severe channeling to one production well was stopped. When air and 1% slugs of foaming agent were injected alternately, the mobility of the air was reduced significantly.

Ugolev *et al.* (1970) found that foamed acid penetrated low pressure carbonate reservoirs more uniformly and more deeply than did regular acid and thus gave better jobs. The air-to-acid ratio was in the range of 1:1 to 5:1 and hence relatively wet foams were being used. He reported that in one region of the USSR, 434 acid foam jobs had been performed starting in 1956 and that these had led to the production of an additional 135,000 tons of oil. This would have to be a very low cost method of stimulation to make it worthwhile.

A number of tests were carried out by Fujii (1970) on comparing foam drive with water drive in a series of cores having permeabilities ranging from about 30 to about 10,000 md (3×10^{-5} to $10 \times 10^{-12} m^2$). On the average, oil recoveries were about 12% higher with foam drive. The ratio of foam drive to water drive recovery generally decreased as permeability increased.

The results of an extensive series of laboratory tests on foam in porous media were reported by Raza in 1969 and published at the end of 1970. He found that the quality of the foam depended on the type of the foaming agent, its concentration in the solution, the physical properties of the porous medium, the pressure level, and the composition and saturation of fluids present. The nature of the foam depended on the type of foaming agent and its concentration in the foaming solution. He felt that the flow behavior of foam in porous media could neither be described in terms of its high apparent viscosity nor in terms of relative permeability concepts, but he came up with no alternative explanation.

He found that the flow of gas could be restricted for indefinitely long periods of time, that of water for shorter periods of time until the foam decays, and that of hydrocarbons only temporarily. He felt that foam could be used to combat coning, to improve sweep efficiency in heterogeneous reservoirs and to improve displacement efficiency in gas injection processes.

The flow of gas through porous media containing aqueous solutions of surfactant was studied by Nahid (1971). Using tracer studies (CH_4 and He), he found that a portion of the gas phase was immobile while the remainder flowed with the forming and breaking of surfactant solution films. The presense of surfactants decreased gas permeability significantly and increased liquid recovery at gas breakthrough. An increase in pressure level and surfactant concentration led to a decrease in gas permeability, which is inconsistent with the results of Abernathy and Eerligh (1966), who used Ottawa sand packs while he used a Berea core. Limited studies on gas-oil systems containing certain surface active silicones and fluorocarbons indicated behavior similar to that for gas-water systems.

His experimental results were in agreement with a combination of two proposed flow mechanisms. One was that channel flow did develop during steady-state conditions and the second was that gas flows intermittently with the making and breaking of film interfaces. Experiments with gas tracers indicated that about one-third of the gas was trapped at least for a while but not permanently. This work, together with that of others summarized earlier, suggests that foam flow in porous media is probably more complex than we realize.

The flow of foam through etched-glass micromodels saturated with detergent solution has been described by Mast (1972). These models had thin "pore spaces" somewhat like those of intergranular porous media. Mast found that the proportion of gas and liquid that was moved through these models as foam depended on the stability of the foam and on the porous medium. With unstable foam the transport of gas and liquid occurs primarily by breaking and regeneration of the foam structures in small pores between larger ones. No liquid channels were observed but some liquid was transported via the Plateau borders.

When the foam is stable, the liquid and gas are transported mainly as foam. Flow through portions of the porous medium can be temporarily blocked by the foam. Foam drainage has a strong effect on foam stability.

In the use of a micellar slug for enhanced oil recovery, a mobility buffer such as a polymer solution must be interspaced between the slug itself and the water which is finally injected. This mobility buffer is necessary in order to avoid viscous fingering into and then destruction of the micellar slug. The cost of polymer is a major component in the economics of the entire process.

The viscous nature of aqueous foam together with its relatively low cost and its miscibility with water suggested this as a possible mobility buffer. If it could also be generated from some of the surfactant in the micellar slug, this would simplify its preparation because an inert, insoluble gas could simply be injected following the micellar slug.

Although work along these lines was carried out by Kamal and first reported in 1970, it was not published in the generally accessible literature until late 1973. In the meantime, a patent had been awarded to Earlougher (1972) for essentially this same process.

Kamal and Marsden (1973) reported that micellar slugs could indeed be displaced by foam in unconsolidated porous media. While secondary recovery of oil by either waterflooding or by a miscible slug followed by foam was about the same in his equipment, a tertiary process after waterflooding by the miscible slug-foam combination lead to additional oil recovery. Because less foaming agent than polymer is required, the process appears to have economic advantages.

An extensive study of foam flow in porous media by Minssieux (1974) was preceded by measurements of the rheology and stability of bulk foam. He found that it was impossible to maintain foam flow in unconsolidated sand packs (50 darcies) ($5 \times 10^{-11} m^2$) one meter long, i.e., he got essentially permanent blocking, but that he could do so in shorter sand packs at even somewhat lower pressure gradients.

X-ray absorption studies on 80 cm long sand packs showed that beyond the first 10 cm or so the liquid saturation in the core is essentially constant at 35% to 45% for foams having qualities ranging from 51% to 96% at injection conditions. He believed that this eliminated the concept that foam advanced as a single fluid in a porous medium. But another interpretation is that a high immobile liquid saturation exists in the porous medium while foam continues to flow as such.

He calculated the viscosity of foam flowing in porous media for qualities ranging from about 50% to about 96% and found that they decreased from about 4 cp ($4 mPa \cdot s$) to less than 1 cp ($1\ mPa \cdot s$) at the highest qualities. Not only was the direction of the change of viscosity with quality the opposite of that which he and others found for bulk foam, but it was lower by two orders of magnitude. Clearly there is a major discrepancy here.

Foam drive of oil in a porous medium led first to gas breakthrough (from partial degradation of the foam), then to production of connate water bank, next to production of an oil-in-water emulsion and finally to foam breakthrough. The latter may still contain emulsified oil, particularly if anionic foamers are used. He found that the overall improvement in recovery by foam drive was not appreciable compared to waterflooding, but it was significant compared to gas drive.

Various abstracts and data bases indicate that considerable work has been done in the USSR on the use of foam in petroleum engineering operations. Abstracts indicated that a good deal is repetitive of that done elsewhere, and also because the field applications have been in unfamiliar areas, there has been little interest in translating it. Two short papers in English translation are those by Evgenev and Turnier (1969) and Evgenev (1974), the first of which has already been noted. In the second paper Evgenev gave data indicating a thixotropic, yield-pseudoplastic behavior although his terminology was different. This study was apparently in connection with subsurface natural gas storage.

6. THE LATTER 1970'S

The use of a foaming agent with injected steam in field application was described by Fitch and Minter (1976). Additional oil beyond that expected from steam alone was apparently recovered at an economical cost. In an addendum to the paper, they mentioned encapsulating the foaming agent in a viscous gel to delay foam formation until the material was well out in the reservoir.

A number of aqueous foams made with anionic and nonionic surfactants were prepared by Kanda and Schechter (1976) and such properties as foaming ability, foam stability and bulk viscosity studied along with several solution properties (surface tension, surface viscosity and wettability). Porous media containing the surfactant solutions were then injected with N_2 gas to generate foam *insitu*. Breakthrough time increased with surface tension and surface viscosity but while displacement efficiency increased with surface viscosity, it decreased with surface tension. Permeability to gas was sensitive to wettability of the system. The presence of salt did not significantly change the results but oil adversely affected the performance.

In another academic study, Aizad and Okandan (1977) described experimental results from the injection of foam into unconsolidated porous media. They believed that their foam flowed as a body and not as the separate components. It behaved like a pseudoplastic fluid with a flow behavior index of about 0.1 for foams made with one surfactant and 0.3 for those made with another. Apparent viscosity, however, did increase with quality. They found that both foams displaced oil from a porous medium better than did water, but also that less of a high quality foam would displace the same amount of oil than would a lower quality foam. Displacement by the latter is, however, faster that by the former.

While Elson and Marsden (1978) were mainly concerned with screening surfactants for extended use at elevated temperatures, they also reported some observations on flow blockage at temperatures only slightly over the boiling point of water. Relative to water saturated porous media, gas flow rate was much less with surfactant solution saturated ones. While the gas flow rate would increase with time, it could be decreased even further than before by injection of more surfactant solution.

In a very extensive patent based on both laboratory work and field tests, Dilgren *et al.* (1978) described the importance of including both noncondensible gas and also an electrolyte (e.g., Nacl) in their steam-foam recipe. Their idea seemed to be to impede steam and oil flow in high permeability-producing channels so they would expand in thickness and thereby produce more oil.

In still another patent Dilgren and Owens (1978) eliminated the steam as such and suggested instead the injection of a hot foam made of aqueous solution, noncondensible gas and surfactant. This process would be used for a less viscous oil than those in reservoirs being produced with steam injection.

The earlier observations of the experimental conditions under which foam would not flow in porous media by Albrecht and Marsden (1970), Kanda and Schechter (1976), and Minssieux (1974) prompted purely theoretical work of Slattery (1979). He found that there was a critical value of the surface tension above which foam cannot be displaced by a given pressure gradient. He concluded that the maximum displacement efficiency occurs when the surface tension was just below this critical value. Also, the displacement efficiency was increased by increasing the surface viscosity as well at the viscosity of the solution itself. These predictions agreed with the published observations of others cited above.

7. THE 1980'S

For the effective application of foam in field tests, the surfactants used must be thermally stable over an extended period of time. This has been tested by Owete *et al.* (1980), who used as the criterion for success not only the chemical stability but also the decrease of gas mobility in porous media containing surfactant, water and displacing gas, relative to those containing only water and displacing gas. At temperatures of 350° to 400° (177° to 205°C) two commercial surfactants -- Suntech IV and Thermofoam BWD -- performed well, while two more were satisfactory, and five additional ones unsatisfactory.

Production by gravity override by foam generated in a two-dimensional, vertical sandpack was observed by Chiang *et al.* (1980). They simulated steam injection by using N_2 gas at ambient temperatures and observed both the displacement front, which could be seen through the clear wall of the model, and breakthrough time. Both liquid recovery and breakthrough time increased when the pack was saturated with surfactant solution instead of just water. Also gravity override was decreased significantly. *In situ* foaming increased with surfactant concentration up to CMC (critical micelle concentration). In one case isobutanol had a favorable affect on a lower molecular weight surfactant (Suntech IV) and an adverse effect on a higher molecular weight one (Suntech IX). In a sandpack initially saturated with a white mineral oil and irreducible water, with a surfactant slug injected prior to N_2 oil recovery was doubled.

Yet another method of generating foam out in the reservoir was patented by Richardson *et al.* in 1980. They listed a number of reactants which would by a change of pH of the system generate N_2 and hence foam in an aqueous solution of surfactant.

For the first twenty years of its use in petroleum engineering, foam was mainly studied as a selective blocking agent for steam used in thermal recovery projects and for underground natural gas storage reservoirs. It was proposed as a blocking agent for liquids in porous media (particularly in patents), but most workers recognized that the liquid would still flow through the foam lamellae. Originally, it was thought that it would be an effective displacing medium for oil because adsorption both on the mineral and oil droplet surfaces as well as dissolution in the oleic phase ruled this out.

With the growing interest in the late 1970's, after much earlier work on the use of carbonated water in floods, attention was focused on using foam as a way of overcoming the major obstacle to CO_2 use on a oil being displaced. The first paper of any significance was that of Bernard *et al.* , which was submitted in mid-1979 and published a year later. Because the critical temperature of CO_2 is below that of most petroleum reservoirs (31°C), there was a temptation to call it a very dense fluid and its dispersions in water an emulsion, but we shall use the terms "vapor" and "foam" here. A good deal of what is said here can therefore be applied to emulsion flow in porous media and vice versa.

Because CO_2 is chemically more reactive in many situations than is steam or hot water as well as being acidic in nature, surfactants had to be selected carefully for their compatibility as well as their effectiveness and long-term stability. While members of all three major surfactant classes were effective, a commercial sulfate ester known as Alipal CD-128 was found to be superior. Its solutions, however, were highly susceptible to acid-promoted hydrolysis, but the products of this decomposition were probably effective in themselves. Its solutions together with CO_2 led to greater mobility reduction in the higher permeability zones just as was the case with foam. A low molecular weight ethyoxylated sulfate of unspecified composition was found to have the best combination of chemical stability, low adsorption and high mobility reduction at reservoir conditions, as well as being a good "emulsifier" for CO_2 and water. Permeability reductions would be removed by the passage of several pore volumes of water through the system and hence were not permanent. As was the case with the early work on the use of foam in steam projects, the descriptions were general in nature and no real rheological data was given here.

While some of the chemical conditions for CO_2 injection are more restrictive than for steam injection, the temperatures are generally much lower. Thus different surfactants are needed to produce stable foams and so Bernard and Holm (1980) patented the use of alkyl polyethylene oxide sulfates which are effective under the conditions of low pH, high salinity and relatively high Ca^{++} concentrations. The ratio of ethylene oxide groups to carbon atoms in the alkyl group suggested these surfactants might be better emulsifiers than foamers.

The first results of a field test using a surfactant "encapsulated" in a polymer gel for injection in a steam drive was presented by Eson and Fitch (1981). These preliminary results in the heavy oil, North Kern Front Field of California, were economically promising. At about the same time, the first annual report on this DOE-supported project was also published by Eson *et al.* (1981). In the following year, another progress report was made by Eson *et al.* (1982) with details given in a paper by Eson and O'Nesky (1982).

In connection with the field test just mentioned, laboratory work was carried out elsewhere to learn more about the flow of foam and gas-surfactant solutions in porous media. Some by Owete *et al.* (1982) were on micromodels made of highly regular, uniform channels etched glass plates between uniformly spaced islands. Air-displacing surfactant solution produced bubbles which often extended over several pore spaces. Even in spite of the uniformity of the system, some liquid and some gas was immobilized in the system. Air mobility in this highly artificial system was decreased by a factor of two over that where no surfactant was present.

Laboratory work on some of the expected problems for a field test were reported by Al Khafaji *et al.* (1980). They found that $CaCl_2$ at concentrations of 0.5% and greater and Nacl at concentrations of 2% and greater produced significant degradation of a particular foamer (Suntech IV). They also found there was phase-partitioning into the oil phase but only small adsorption on a quartz sand. The steam mobility was reduced significantly in the presence of surfactant solutions and also the average steam saturation in the saturated steam zone increased as the steam zone grew.

In a paper screening surfactants for use in generating foam in steam injection projects, Dilgren *et al.* (1982) found two necessary ingredients beyond those already recognized. One was the presence of a small amount of a permanent gas such as N_2 in the steam so that there would not be a complete collapse of the foam when the steam condensed. The other was the presence of at least a small amount of NaCl (several percent) which was necessary for the dodecylbenzene sodium sulfonates and the $C_{16} - C_{18}$ alpha olefin sodium sulfonates they studied. They found that the latter yield what they called stronger foams than the former. After laboratory tests in Ottawa sand packs, they used the foamers in a pilot test described later and found both the predicted increased pressure at the injection wells and increased oil production rate.

More laboratory results plus those from field tests were published by Doscher and Hammerschaimb (1982) and then presented in a more detailed report the following year. Details of the laboratory procedures and the results of the tests are given in the paper. Besides the minor effects of KC1 and Ca^{++} on foam volume, there was a major effect of crude oil improved the performances of some surfactants, particularly at somewhat elevated temperatures. Tests in sandpacks eliminated most remaining foamers. Corrosion inhibitors had an adverse effect on surfactants. As had Dilgren *et al.* (1982), they found that the presence of a noncondensible gas in the steam was essential. Final laboratory testing in a 16-ft (4.9 m) sandpack indicated that Thermophoam BW-D (Farbest) should be field tested. This was done in five heavy oil fields of California over a period of two years and enhanced recovery found. They believed that besides the increased volumetric conformance expected, there was additional oil recovery from emulsification, lowered interfacial tensions and entrainment of oil droplets in the steam and hot water phase.

Commercial foaming agents are often mixtures of different chemical species of various sorts. Some have simply different hydrocarbon chain lengths resulting from a petrochemical synthesis process or from the occurrence of mixtures in nature and more often than not this enhances their performance. Others have different functional groups [such as those mentioned above in the work of Dellinger *et al.* (1984)] and the combination is better than the sum of the parts. To evaluate the effect of chain length alone, Sharma *et al.* (1982) studied the foaming behavior and other surface chemical properties of mixtures of $C_{12}H_{25}SO_4Na$ and the even C-atom alcohols from C_8 to C_{16}. They found that both breakthrough time and fluid displacement efficiency in sand packs and Berea sandstone were at a maximum when both the alcohol chain length and that of the Na alkyl sulfate were the same. Also at this condition there was a minimum in the surface tension and bubble size, but a maximum in surface viscosity and bubble stability as well as fluid displacement efficiency and breakthrough time.

In later study along these lines, Sharma and Shah (1983) showed that there was a maximum in oil recovery at air-foam breakthrough, at steam-foam breakthrough and at surfactant breakthrough when the alkyl sulfate and alcohol had the same chain lengths. They also reported that for a system made up of 0.005 $M\ NaC_{12}\ SO_4$ and 0.00005 $M\ C_{12}\ OH$, the bubble size increased much more rapidly at $80°C$ than at $20°C$.

In a paper that was more like a research proposal than a finished piece of work, Heller *et al.* (1982) discussed the expected performance of a high-pressure CO_2-in-water "foam" which, because of the low compressibility and high density of CO_2 under these reservoir conditions, behaved more like an emulsion than a foam. For best performance they suggested the aqueous phase content be as low as possible, which would correspond to a high-quality foam, and that the mobility of this "foam" be adjustable to be about that of an oil bank which was expected to be formed.

In work indirectly related to that described here, Blair *et al.* (1982) described how the injection of thin film spreading agents (TFSA) with cyclic steam injection lead to increased oil production. While these are certainly surface active, no mention was made of foam here and in related papers and patents by these authors.

In a progress report on a US DOE-sponsored project for finding suitable surfactants for CO_2 mobility control, Patton *et al.* (1983a) found ethyoxylated adducts of C_8 to C_{14} linear alcohols and low molecular weight co-polymers of ethylene oxide and propylene oxide were the most promising. These withstood degradation for two weeks at 125°F (52°C) but sulfated esters of ethoxylated C_9–C_{16} linear alcohols did not.

The flow behavior of CO_2-water foams in capillary tubes of different lengths and diameters was described by Patton *et al.* (1983b). As expected, they could be described by the power law relationship and behaved like pseudoplastic fluids. Apparent viscosities of 10 to 100 cp (10 to 100 $mPa \cdot s$) were reported but unfortunately no K and n values were given. Unlike the much earlier work of Raza and Marsden (1967) and David and Marsden (1969), they did not feel that they had fluid slippage in the capillary tubes. A graph of apparent viscosity vs. quality increased rapidly and went through a maximum at about 95% quality, as would be expected.

While several authors had described over the years the rheological properties of foam, as measured in capillary tubes and concentric cylinder instruments, none gave the elegant theoretical treatment of the subject as did Hirasaki and Lawson (1985). They emphasized the importance of foam texture in determining the nature of the foam flow. Most of their work dealt with the flow of bubbles having radii close to those of the tubes and so foam could not be considered here as a continuum and treated as a fluid. When the bubbles were large compared to the tube radius, the apparent viscosity varied to the 2.5 power and to the 2.0 power when the bubbles were small compared to the tube radius. For uniform-sized foams, the apparent viscosity varied with the -2.0 power of bubble radius small relative to tube radius and the -3.0 power when well explain the differences in results between different laboratories and resolve the different viewpoints on foam vs gas-surfactant solution flow in porous media.

In the final report on a US DOE-sponsored project on mobility control of CO_2 by Heller and Taber (1983), they described results not only for CO_2-foams but also on polymers dissolved in CO_2. For the former, they screened more than 60 commercially available surfactants for their suitablility but also for their adsorption on reservoir rock samples. For the polymer studies they did not have much success. This report contains a great deal of information which should be studied carefully by new workers in the field. Some were presented in a more accessible source the following year by Heller (1984). Here, he specifically mentioned that the most promising surfactants for CO_2 foams were anionic sulfonate surfactants. He also dwelt on the use of WAG (Water-Alternated-with-Gas) as a means of introducing the components into the reservoir.

The results of extensive field tests carried out on a DOE-sponsored project were presented in a detailed report by Bowman (1983). These were preceded by laboratory work first on surfactant screening and then on steam displacements with surfactants in large porous media. The former included both a mixing test developed by Chevron and also a modification of the refluxing method described by Elson and Marsden (1978). Again the importance of noncondensible gas as well as corrosion inhibiters were recognized along with the desirability of partial rather than complete blocking of steam in highly permeable zones. The five field tests in the Midway-Sunset, Cat Canyon and San Ardo Fields of California either led to production of incremental oil or else lead to other positive benefits.

Another report on a field test described by Eson and O'Nesky (1982) was presented by Brigham *et al.* (1984). They reported no operational problems when injecting surfactant solution and nitrogen gas with steam in the Kern River Field. Tracer studies, injecting profiles, temperatures at he producing wells, logging and well tests all indicated at least qualitatively that steam was effectively diverted toward previously unswept areas. A production response was observed after injection of each slug of surfactant solution.

The necessity of having inert gas such as N_2 along with the steam was reiterated by Duerksen (1984). He also emphasized that the foaming agent must be one that would regenerate foam at flow rates far from the injection well. He found that foamability varied indirectly with temperature and directly with N_2 concentration. He screened 50 commercial and experimental surfactants and found four commercial ones which were particularly good. These were alpha olefin sulfonates which were relatively insensitive to foam liquid volume fraction, had good thermal stability (as did most of the sulfonates) but were somewhat affected by brine. One of his company's proprietary sulfonates was then selected for the field tests described later on.

Unlike most workers studying use of foam for mobility control, Hu *et al.* (1984) felt that it was more profitable to study foam flow in capillary tubes than in sand packs. They recognized that the relative size of bubbles and tubes are important as had others, but a good deal of their work was on flowing lamellae. As the title of their paper indicated, they used alpha-olefin sulfonates for most of their work.

It is well known that mixtures or combinations of more than one surfactant will often be more effective than a single, chemically pure species because while some are more effective in foam generation others are more effective in stabilization. Dellinger *et al.* (1984) carried out screening tests on a large number of surfactants and their combinations and found that both amine oxides and amides improved stability for many anionic surfactants. They recognized, however, that because of chromatographic separation of surfactant mixtures during flow and displacements in porous media, such synergistic effects observed outside porous media are an illusion.

Foams made of CO_2 were studied by Wang (1984) who reported that their stability increased with increasing pressure and decreased with increasing temperature. Their foams deteriorated rapidly when they came in contact with SACROC and Rock Creek crude oils, two candidates for field in use. He found that while his foams improved oil recovery only slightly and that too high a surfactant concentration could generate a rigid foam and lead to lower recovery.

The results of many field tests using thin-film spread agents with steam injection were reported recently by Blair *et al.* (1984). While it is not believed that these act as foaming agents, they are certainly surfactants that are effective in EOR, probably by affecting rock wettability and possibly the properties of the oil-hot water interface. In any event, they reported that 4700 times the volume of oil was recovered as chemical used.

Two very successful field tests based on the laboratory work of Duerksen (1984) described earlier were presented by Ploeg and Duerksen the next year. They found that their proprietary sulfonate both increased oil recovery by steam injection significantly and did so economically. To get proper mixing of the sulfonate and N_2, they used a "static in-line mixer," which has almost no pressure drop across it. They felt that sulfonate slug injection was an acceptable alternative to continuous injection but were unable to optimize both the amount and frequency of the sulfonate injection. Nor were they able to determine the amount of the non-condensible gas (N_2) to be injected by the results of these tests. Sulfonate concentrations of

0.1% of active components were sufficient and these caused no oil handling or treating problems such as emulsions. For one test only 0.25 lb sulfonate/bbl (0.71 kg/m^3) incremental oil production was used and 1.0 lb/bbl (2.9 kg/m^3) for the other test. They felt that the incremental oil produced was bypassed oil which would not have been otherwise produced and thus was beyond what would be considered as reserves. Finally, there was a long-term incremental oil production which followed in the sulfonate injection period, possibly due to remaining N_2-foam or possibly due to a permanent change in the reservoir relative permeability.

The effect of temperature on various foam properties was described by Sharma *et al.* (1985). Average bubble size decreased with increasing temperatures, but increased with elapsed time. While the ability of their surfactants to generate foam increased with temperature, the foam stability decreased. Effective air mobility decreased with temperature and pressure gradient.

While some of the first work on foam in petroleum engineering research by Fried (1961) was on using aqueous foams as a displacement medium, some of the most recent by Al-Attar (1976, 1985) has been on use of oil-based foams for the same purpose. An oil-based foam would, of course have the advantage relative to a water-based one that it would displace the oil miscibly but it would also be significantly more expensive. This was first reported in his dissertation and then summarized in a three-part paper submitted for publication. Unlike aqueous foams, data for his samples in capillary tubes gave lines of slope unity on log τ vs. log γ plots indicating Newtonian behavior. Linear plots indicated small yield stresses which increased with quality (55 to 90%) as did viscosity. Externally generated oil foam injected in porous media lead to greater recovery than did either gas or water injection. For internally generated foam, he felt that the oil recovery was significantly higher than for gas injection alone.

As of the spring of 1985, papers are still being presented and published on foam flow in porous media. Both laboratory research and field testing continue as do several applications mainly in thermal recovery projects. While we understand the main aspects of foam flow or the simultaneous flow of surfactant solutions plus gas or vapor, many problems remain to be solved. Some of these have to do with the chemical aspects of the surfactants such as their chemical and microbiological degradation, thermal stability and adsorption on mineral surfaces or at oil-water interfaces. We also need to know better when we can consider foam to flow as a distinct fluid and when we must consider instead the simultaneous flow of surfactant solution plus gas. The latter is needed for simulation of reservoir engineering processes involving these interesting materials.

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