Energy Sources, Volume 12, 479–497
Printed in the UK.

0090-8312/90 $3.00 + .00

Aqueous Foams for Control of Gas Migration and Water Coning in Aquifer Gas Storage

P. PERSOFF
K. PRUESS
S.M. BENSON
Y.S. WU

Earth Sciences Division
Lawrence Berkeley Laboratory
Berkeley, CA 94720

C.J. RADKE
P.A. WITHERSPOON

University of California
Berkeley, CA 94720

Y.A. SHIKARI

Gas Research Institute
Chicago, IL 60631

Abstract *Two causes of poor recoverability are migration of stored gas far from the injection well and upward coning of water into withdrawal wells. The authors conducted laboratory and numerical simulation investigation of the use of aqueous foams to block the flow of gas or liquid to ameliorate these problems. Experiments in sandstone cores showed that foam reduces the permeability to gas and liquid by approximately three orders of magnitude. A numerical simulation study showed that water coning could be significantly delayed by placing a horizontal foam lens just above the gas-water interface. Also discussed are the conditions for forming foam in situ, the feasibility of emplacing a foam bank, and the durability of permeability reduction. Laboratory experiments and numerical simulation indicate potential for significantly improving the efficiency of aquifer gas storage with aqueous foams. A field trial of foam to prevent water coning is recommended.*

Keywords foam, blocking, permeability reduction, gas storage, coning.

Introduction

The transmission and distribution segments of the gas industry in the United States share a common interest in gas storage. To meet peak loads and ensure dependable delivery of gas to all end users, gas storage has become a vital link in the supply, transport, and distribution network. Of the various forms of natural gas storage technologies adopted, large-scale seasonal storage by utilities in underground formations is perhaps the most prevalent.

Two aspects of underground storage of natural gas—migration of gas beyond the designated storage area during the gas injection cycle and water coning into wells during the withdrawal cycle—are addressed in this study. During the formation of the initial storage volume in an underground aquifer, some of the injected gas fingers away from the main bubble, sometimes for long distances, because of the adverse mobility ratio between water and gas. This migrated gas is often difficult to recover, leading to a reduced percentage of working gas (the fraction of total gas in storage that can be recovered during a withdrawal season). It is, thus, important to devise an effective means of controlling such migration. Another aspect of gas storage operation pertains to a typical wellbore problem in aquifer gas storage where water coning during gas withdrawal significantly reduces the deliverability (or well productivity). Elimination or significant delay of water coning in the production zone is, thus, highly desirable during the withdrawal season.

In the past, these problems have been dealt with by injection of large volumes of base gas (typically twice as much as the working gas, with the proportion being larger in specific reservoirs), but long-term increases in both interest rates and the value of natural gas have impelled a search for methods to control gas migration and water coning. One possible solution to these problems is the use of aqueous foam as a mobility control agent. The basic idea of foam-protected gas storage is to emplace a suitable foam barrier in an aquifer that would confine the stored gas in a compact volume around the injection wells (Witherspoon et al. 1987). Two possible applications are shown in Figure 1*a* and *b*. Because the proposed foam would contain about 65% by volume of natural gas, it would provide a compatible and easily applied means of mobility control.

For successful application of foam to underground storage of natural gas, it must be technically feasible, economical, and environmentally acceptable. The economics of foam protection must be calculated for each site, based upon such factors as the value of natural gas and of storage capacity, and the geology of the reservoir. Several concepts for foam application were presented, and the economics of foam protection discussed, with some example calculations, by Witherspoon et al. (1987). In general, the cost of foam injection is heavily weighted by the cost of drilling wells for foam injection, so the economics are most favorable when the volume of foam to be emplaced is small relative to the increase in working gas, as in the use of a foam barrier to increase storage capacity by lowering a spill point, or when foam can be emplaced through an existing well, as for water-coning control. Recent improvements in horizontal-well drilling may allow a long foam barrier (as would be needed to lower a spill point) to be emplaced through a single well, also improving the economics.

Environmental acceptability also must be determined on a site-specific basis. Fortunately, the existing use of surfactants in oilfield applications suggest that if the aquifer is not classified as a potential underground source of drinking water (<10,000 mg/L total dissolved solids), injection of nontoxic, biodegradable surfactants should be possible.

The purpose of this article is to examine the technical questions that must be answered to make the proposed applications of foam feasible. We report results of laboratory experiments that answer some of these questions and assess our state of knowledge for others. The technical questions include:

- How is foam formed in porous media? What conditions (e.g., flow rates, liquid saturation) are necessary for the formation of foam?
- How can foam best be emplaced in a formation?
- By what mechanism does foam reduce the permeability of a porous medium to gas and to liquid? What is the degree of permeability reduction?

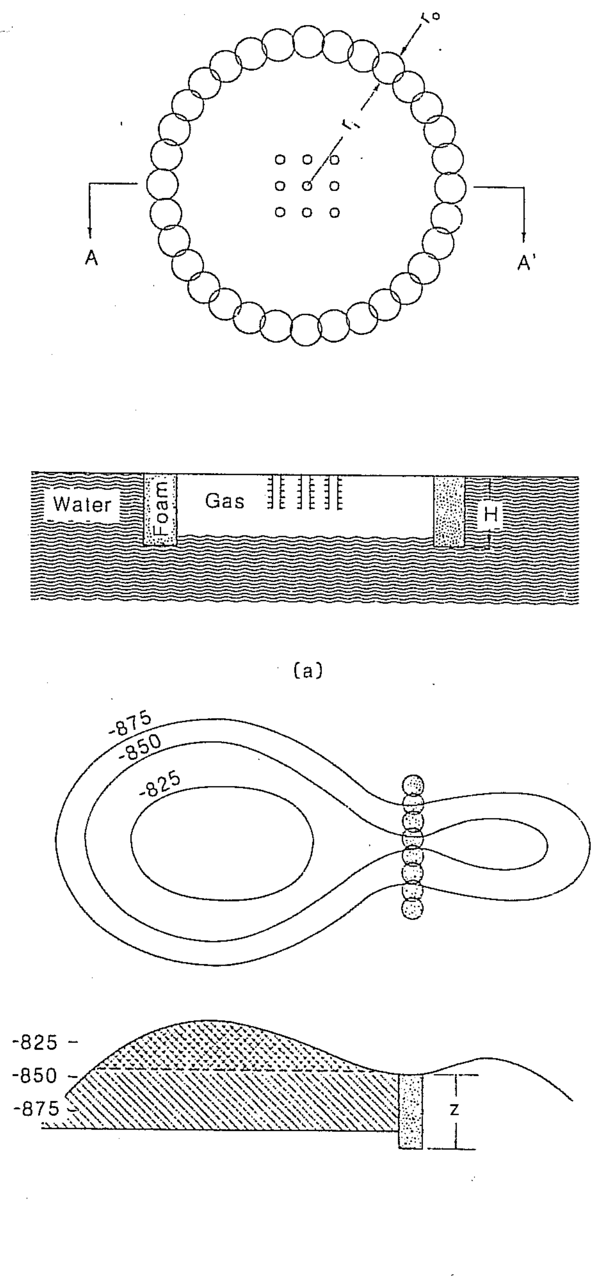

Figure 1. Application of foam to improve underground gas storage by controlling gas migration (after Witherspoon et al. 1987). (*a*) Foam plumes formed at peripheral wells intersect to form a continuous barrier, containing stored gas in a more compact bubble near the injection-withdrawal wells. The use of foam obviates the need for natural closure. (*b*) A small foam barrier to cut off a spill point produces a large increase in storage capacity.

- How long does the permeability reduction last? How can it be made to last longer?
- What is the most effective way to use foam for underground gas storage?
- How can foam be broken, if desired?

Foam Generation in Porous Media

Foam is a mixture of gas and liquid phases such that the gas phase is not continuous but rather has been broken up into many bubbles, separated by thin liquid films called lamellae. (One or more continuous gas paths may also exist through a length of porous medium.) The question of foam formation is therefore the question of lamellae formation. Lamellae are generated when gas invades liquid-filled pores. Surfactant is not necessary for the production of lamellae, but lamellae are thermodynamically unstable because they represent extended surface area, and without surfactant they rupture immediately.

Ransohoff and Radke (1988), from observations of foam in transparent glass beadpacks, concluded that lamellae are formed by two mechanisms: leave-behind and snap-off. When two parallel gas channels invade adjacent connected pores, a lamella may be left behind between the two pores. Leave-behind lamellae are produced mainly during initial gas invasion into a surfactant-saturated medium. Lamellae formation by snap-off was first described by Roof (1970). Here, lamellae are produced continuously and therefore exert a much larger effect to reduce the gas permeability. In accordance with the accompanying reduction of gas permeability, foam containing many snap-off lamellae are termed strong foams (typically reducing the gas permeability by orders of magnitude), and foam containing only leave-behind lamellae are termed weak foams.

Snap-off can only occur in certain pore throat-pore body combinations, and a minimum gas velocity must be exceeded to invade these sites. Ransohoff and Radke (1988) experimentally demonstrated the existence of such a critical gas velocity for formation of a strong foam in initially liquid-saturated beadpacks. In our experiments with sandstone, described below, the initial liquid saturation also was 100%, and strong foam was formed in every experiment, whether only gas was injected or gas and liquid were injected simultaneously. The minimum superficial gas velocity studied was 1 m/day. This suggests that the minimum velocity for strong foam formation in saturated sandstone is below this value.

Emplacing a Foam Bank in a Porous Formation

Emplacement of a foam barrier to block gas flow as described by Witherspoon et al. (1987), or to block liquid flow as described below, requires that foam be driven some distance from an injection well. The essential problem is that foam is a non-Newtonian fluid with large apparent viscosity, and the injection pressure must be limited to avoid fracturing the formation. These factors combine to limit the distance and velocity at which foam can be driven from an injection well.

We conducted a series of experiments (Persoff et al. 1989) to study the relationship of foam pressure gradient to gas and liquid flow rates. The apparatus used in those experiments, shown in Figure 2, was also used for the experiments reported in this article. Pressure and liquid saturation (by gamma-ray densitometry) were automatically measured at several locations along the sandstone core. Liquid was delivered by a constant rate pump, and nitrogen gas was delivered at either constant mass flow rate or constant injection pressure. Back pressure was maintained by a dome-loaded back-pressure regulator.

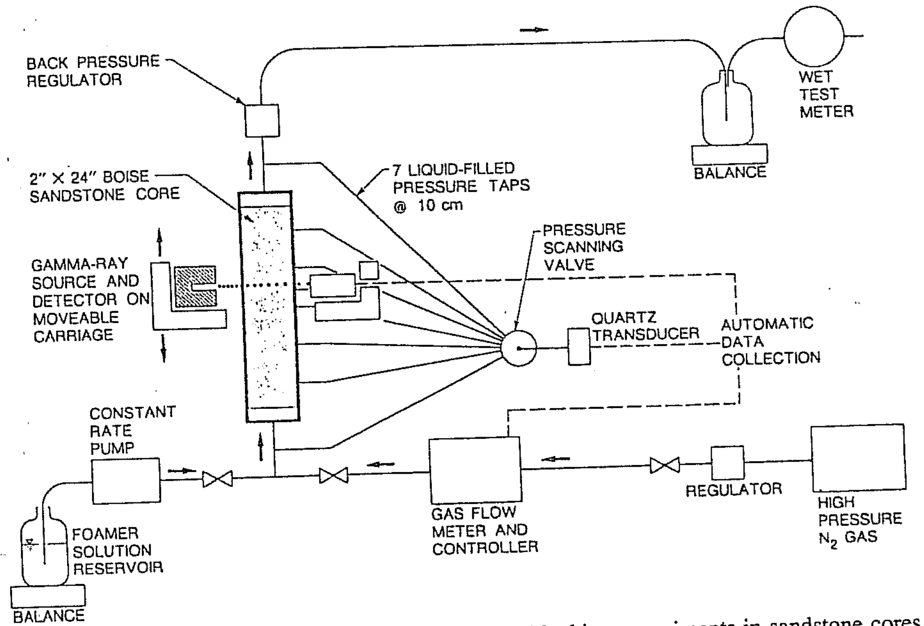

Figure 2. High-pressure apparatus for foam flow and blocking experiments in sandstone cores.

In the work of Persoff et al. (1989) the pressure gradient was found, surprisingly, to be essentially independent of the gas flow rate and (except at the very lowest liquid flow rates) approximately proportional to the liquid flow rate. Quantitatively, this is expressed as

$$\left(-\frac{dp}{dx}\right)\frac{k}{\mu_{liq}v_{liq}} = \frac{1}{k_{rl}} = \text{constant (dimensionless)} \tag{1}$$

where p is pressure, x is distance, k is the intrinsic permeability of the sandstone, v is the superficial velocity, μ is viscosity, and k_{rl} is the relative permeability to liquid. This behavior is accounted for by the separate effects of the gas and liquid flow rates on the number of lamellae flowing in the gas phase. The value of the constant depends upon the foamer solution and porous medium. Using the foamer solution described below, we found that this value was approximately 1000 in 1.3 μm^2 (1300 millidarcy) Boise sandstone, and approximately 3000 in 0.19 μm^2 (190 millidarcy) Berea sandstone. The difference apparently results from the different relative permeability curves for the two sandstones. In both experiments, the observation that $1/k_{rl}$ was constant agreed with the independent observation that the liquid saturation in the core was uniform and constant over order-of-magnitude changes in gas and liquid flow rates. The practical implication of this finding is that, to emplace a foam barrier with minimum injection pressure, liquid velocity must be very low or zero (i.e., inject gas only).

Formation of a Spaced Foam Block

Another approach to drive foam in situ to a large distance, with limited injection pressures, is to create the foam block at some distance away from the injection well, rather than immediately adjacent to the borehole. This would reduce the distance through which the steep pressure gradient characteristic of foam is exerted, and in addition the region nearest the well, where pressure gradients in radial flow are normally steepest, would be free of foam. For small storage projects, a spaced foam block could also possibly allow gas to be stored inside the annular foam barrier, using the same well for foam injection and for gas injection and withdrawal. The concept of injecting a surfactant solution, displacing it with brine, and then injecting gas, was introduced in an early patent (Bond and Bernard 1967), but no confirming data have been presented to show its feasibility.

We investigated experimentally the feasibility of creating a spaced foam block. The core (60-cm-long, 1.3 μm² [1300 millidarcy] Boise sandstone) was initially saturated with foamer solution, and 0.42 pore volumes (PV) of brine were injected to displace the foamer solution 25 cm away from the injection point before injecting gas. (The specific foamer solution and brine are described in the next section.) Next, gas was injected at a constant injection pressure of 5.17 MPa (750 psi) against a back pressure of 4.91 MPa (712 psi). (All pressures are absolute.) Figure 3 shows the pressure profiles developing over time as 0.8 PV of gas were injected. The steep pressure gradient in the region 40 to 60 cm shows that the gas mobility was low in this region, where a strong foam was formed, while the flat pressure gradient in the region 0 to 40 cm shows that the foam bank was spaced away from the inlet. Before gas was injected, the core was saturated with foamer solution from 25 to 60 cm, and with brine from 0 to 25 cm. As gas displaced brine in the inlet region, the foamer solution was displaced an additional 15 cm through the core, so that the region of reduced gas mobility extended not from 25 to 60 cm but from 40 to 60 cm. Because of desorption of the surfactant and hydrodynamic dispersion, the displacement of foamer solution by brine was not complete. As a result, the region 0 to 40 cm was not completely free of foam, but actually contained a weak foam, as evidenced by the small but non-zero pressure gradient.

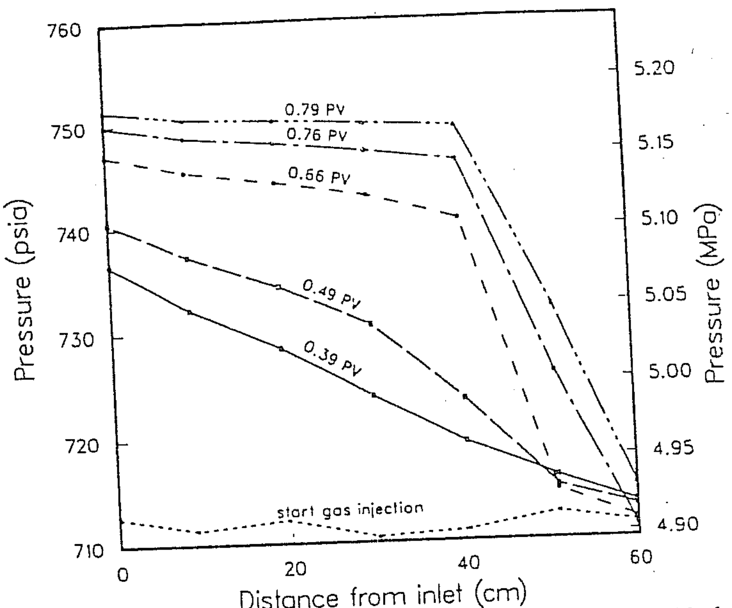

Figure 3. Pressure profiles during development of a spaced foam block.

Permeability Reduction by Foam

Foamer Solution

As mentioned previously, the gas-blocking effect of foam in porous media results from numerous individual lamellae, each of which is thermodynamically unstable, but made metastable by the presence of surfactant in the liquid phase. Therefore, the gas-blocking effect of foam eventually decays as individual lamellae rupture. We screened combinations of surfactants to develop a formula that was compatible with high-salinity, high-hardness brine typical of gas-storage reservoirs and that would produce lamellae resistant to spontaneous rupture. We used a synthetic brine, representative of the Mt. Simon aquifer in Illinois, where several gas-storage projects are located. The brine contained 5410 mg/L Ca; 1260 mg/L Mg; 66,700 mg/L total dissolved solids; and 18,750 mg/L as $CaCO_3$ hardness. Enhancement of lamella stability by combining surfactants has been reported previously (Witherspoon et al. 1987). The resulting foamer solution, used in all experiments, was 1 wt% alkylethoxysulfate surfactant (Shell Enordet AES 1215-9S, i.e., $CH_3(CH_2)_{11-14}-(O-CH_2CH_2)_9-OSO_3^-Na^+$, or Stepan Steol 7-N, a commercially available near-equivalent), plus 0.2 wt% lauryl alcohol. The insoluble long-chain alcohol was incorporated into the foamer solution by dissolving the surfactant in the brine, warming it to 45°C, and adding the liquid alcohol while stirring. After several days, the excess alcohol separated out from the solution and formed a buoyant turbid layer. The clear lower layer was separated and used for experiments. Failure to remove the turbid alcohol layer caused formation of a skin at the sandstone injection face in early experiments.

Gas Blocking by Foam

Experiments in Sandpacks at Low Pressure. In preliminary experiments, we demonstrated foam formation, complete gas blockage by foam, and durability of foam blocks in 60-cm-long, 1.3-cm-diameter, 20-μm^2 (20-darcy) permeability unconsolidated sandpacks, using the apparatus and method described by Witherspoon et al. (1987). The sandpack was initially saturated with the foamer solution. Gas was injected at constant pressure and liquid at constant flow rate; gas and liquid flow rates were measured by timing and weighing foam exit flow into a graduated cylinder. Foam was formed in the sandpack and flowed at steady state conditions for about 1 hr. Then the gas injection pressure was rapidly reduced from the injection pressure to the holding pressure, and liquid flow was stopped at the same time. In a few minutes, flow of foam from the sandpack stopped, indicating that gas flow was blocked. After blocking occurred, any further gas emerging from the sandpack was collected by displacing water in an inverted graduated cylinder. In this way both the time of first gas breakthrough and the flow rate at breakthrough were monitored.

Blocking was achieved in all cases when the absolute holding pressure was less than 75% of the absolute injection pressure. We interpret this observation to mean that as the bubbles expanded due to the pressure reduction, the lamellae rearranged themselves into a configuration that completely blocked the flow of gas. Eventually, as individual lamellae ruptured, a gas flow path through the sandpack was established, and flow (gas breakthrough) was observed.

Foam blocks lasted longest in experiments in which 0.5 wt% guar (Galactosol 253, Henkel Corp., Houston, TX) was included in the foamer solution. In these experiments, extremely high injection pressure was needed to inject foam because of the high liquid viscosity. Foam was formed in the sandpacks by injecting gas at 2.17 MPa (315 psi) and liquid at 2.01 mL/min. Steady state was reached with a gas flow rate of 5.46 standard cm^3/min. The gas injection pressure was then quickly reduced to 0.17 MPa (25 psi), and the liquid flow was stopped. Gas flow was completely blocked in these experiments. Gas first broke through after two months. Figure 4 shows the gas permeability calculated from the measured flow rates. After 100 and 250 days in duplicate tests, the permeability rapidly increased. The gas injection pressure needed to form foam in these experiments was much greater than the gas injection pressure needed in several similar experiments without guar, but the duration of permeability reduction was greater. Because of the extremely high pressure gradients (3.4 MPa/m [150 psi/ft]) needed to inject guar-stabilized foams into the sandpacks, however, we decided not to use guar in further experiments.

Experiments in Sandstone Cores at High Pressure. For more realistic simulation of gas-storage conditions, experiments in foam formation, displacement, and blocking were conducted in 5.1-cm-diameter, 60-cm-long sandstone cores at elevated back pressure, using the apparatus shown in Figure 2. Experiments were conducted in a Boise sandstone core of permeability 1.3 μm^2 (1.3 darcy) and porosity 0.25 and in a Berea sandstone sandstone core of permeability 0.19 μm^2 (190 millidarcy) and porosity 0.19.

To measure the permeability to gas, dry gas was injected through a foamed sand-stone core under either constant injection pressure or constant mass-flow rate control. In none of these experiments did we observe complete blocking of gas flow, as has occa

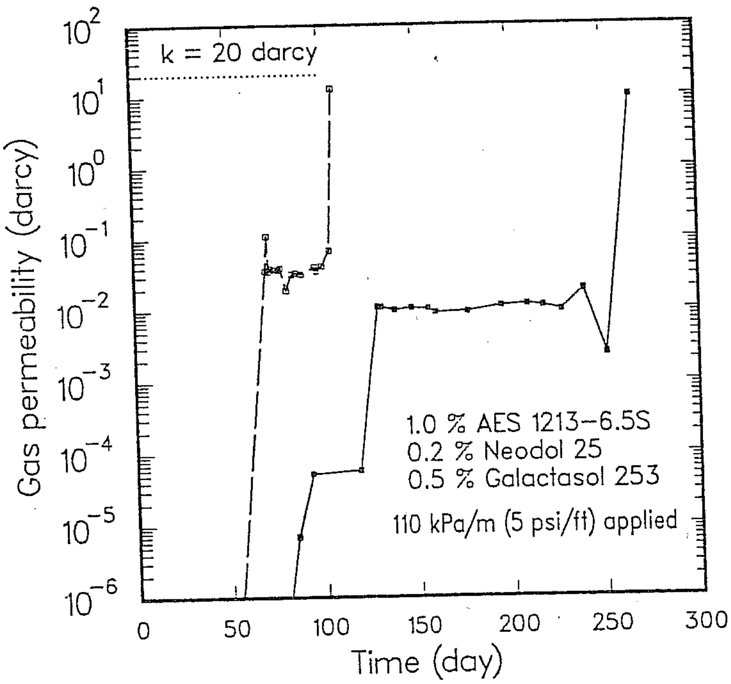

Figure 4. Duration of low permeability in duplicate sandpack experiments in which 0.5 wt% gu polymer was added to the foamer solution.

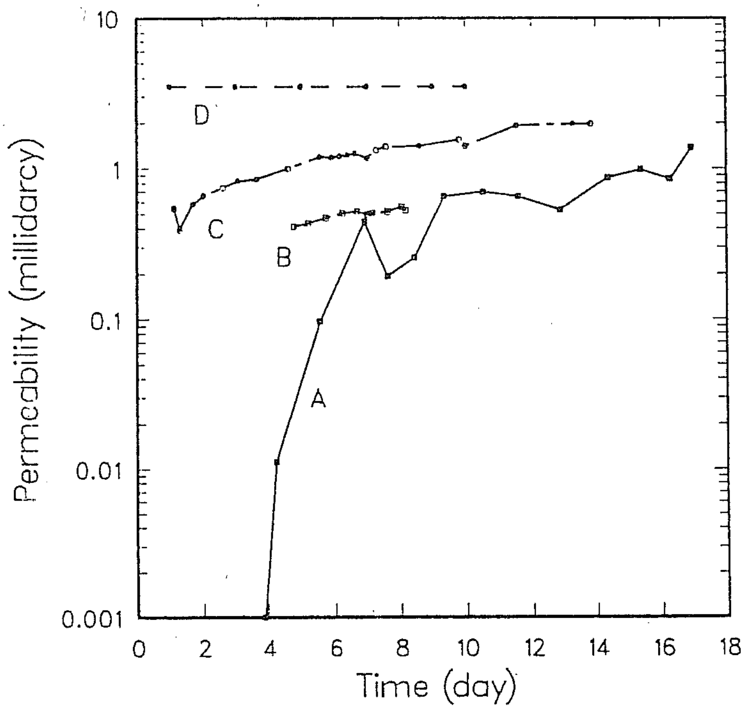

Figure 5. Gradual increase in gas permeability of foam-filled sandstone core, four experiments. In all experiments, the core was initially saturated with the foamer solution. (*a*) Foam generated by simultaneous injection of gas and liquid at controlled flow rates. Then liquid flow stopped and gas injection pressure reduced. Permeability measured at constant gas injection pressure. Permeability of sandstone without foam = 1.3 μm^2 (1300 millidarcy). (*b*) Foam generated by injection of gas at constant pressure. Additional slugs of foamer solution injected (see Fig. 7); permeability shown is after final slug. No injection pressure reduction. Permeability of sandstone without foam = 1.3 μm^2 (1300 millidarcy). (*c*) Foam generated by injection of gas at constant rate into 1.3 μm^2 (1300 millidarcy) core. No injection pressure reduction. (*d*) Foam generated by injection of gas at constant rate into 0.19 μm^2 (190 millidarcy) core. No injection pressure reduction.

sionally been reported (Minssieux 1974; Hanssen 1988). However, the permeability to gas was reduced below the intrinsic permeability of the rock by approximately three orders of magnitude, indicating that a very substantial reduction in gas leakage rate could be achieved. The permeability to gas was initially very low in all these experiments, gradually increasing to about 1 or 2 $\times$ 10^{-3} μm^2 (1 or 2 millidarcy) during 14 days.

In four experiments, the permeability to gas generally increased gradually with time, as shown in Figure 5. This behavior was observed whether the foam was formed by simultaneous injection of gas and liquid, or injection of gas only, whether the gas was injected at constant pressure drop or constant rate, and whether the permeability of the core was 1.3 or 0.19 μm^2 (1300 or 190 millidarcy). The details of each experiment are given in the caption of Figure 5.

In the first experiment, we attempted to block gas flow completely, by reducing the gas injection pressure, as we had done in the low-pressure experiments. However, the same procedure at elevated back pressure in sandstone did not produce complete blockage. At steady state, the injection pressure was 6.75 MPa (980 psi) against 5.27 MPa (765 psi) back pressure. It was thus impossible to reduce the gas injection pressure far enough to block gas flow completely by bubble expansion (i.e., 25%), as had been done in the low-pressure experiments. At steady state, the gas injection pressure was suddenly reduced from 6.75 MPa (980 psi) to 5.45 MPa (790 psi) so that a pressure drop of 0.17 MPa (25 psi) remained across the core. The pressure profile through the core then evolved to a uniform slope, and gas continued to flow through the core at a gradually increasing rate, as shown by Figure 5 (curve A). This experiment was discontinued after 17 days.

Because the pressure-drop/flow-rate experiments showed that the most feasible way to form a foam bank in situ was to inject gas only, in further experiments foam was formed by injecting only gas into a core initially saturated with foamer solution (curves B–D of Figure 5).

The increase in permeability shown in Figure 5 (curve A) suggested that foam might need to be regenerated periodically. Therefore, a method to regenerate foam was investigated. In experiment B, gas was injected into the core at 5.17 MPa (750 psi) against a back pressure of 4.82 MPa (700 psi). Figure 6 shows the gas flow rate at constant injection pressure. Gas initially invaded rapidly, displacing liquid from the core, and as foam advanced through the core, the flow rate decreased. Gas broke through after one hour, at a flow rate corresponding to a permeability of 1.9 × 10^{-3} μm² (1.9 millidarcy) or a reduction by a factor of 680 compared to the initial permeability of the core. At this point, an additional 0.03 PV slug of foamer solution was injected while the inlet gas pressure was maintained. As shown in Figure 6, the gas flow immediately dropped to almost zero and slowly recovered. Although gas permeability through the core was

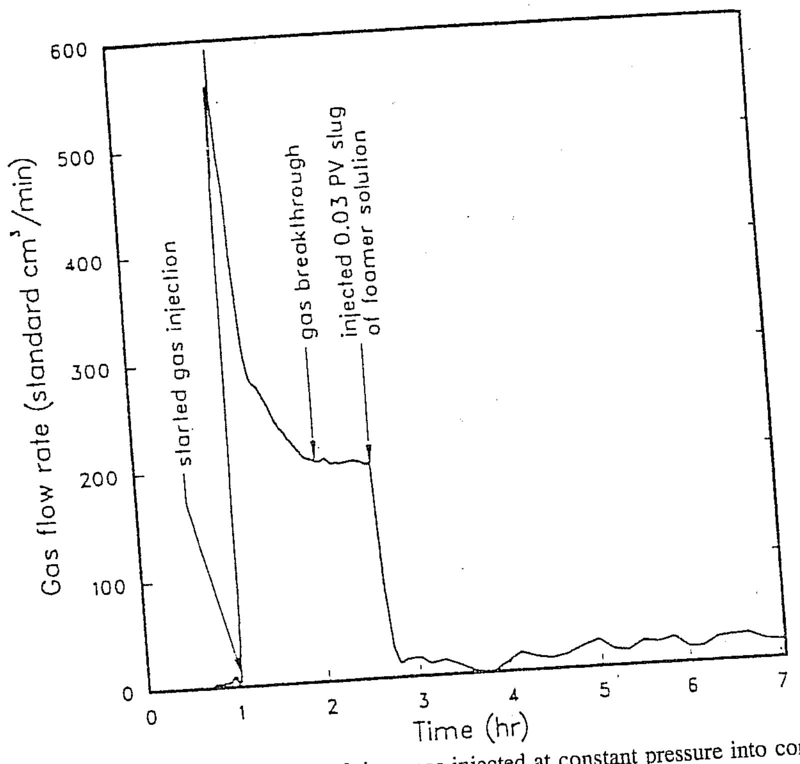

Figure 6. Gas flow rate as a function of time; gas injected at constant pressure into core initially saturated with foamer solution.

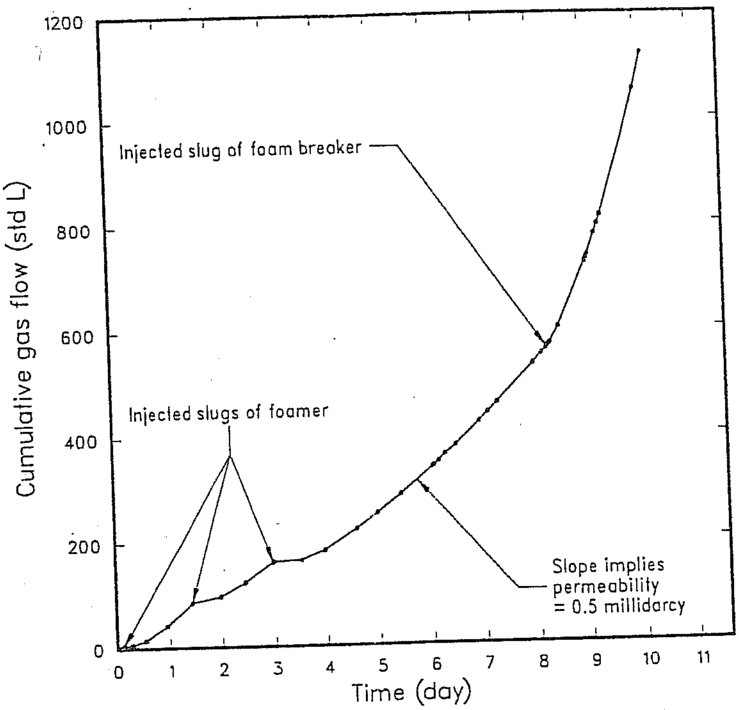

Figure 7. Cumulative gas flow as a function of time; gas injected at constant pressure into core, showing effect of additional liquid slugs (Experiment B).

1.9×10^{-3} μm^2 (1.9 millidarcy) one hour after gas invaded the initially saturated core, it took about 30 hours for the gas permeability to regain that value after the slug was injected. Figure 7 shows the cumulative gas flow through the core at constant injection pressure. As shown in this figure, two more slugs were injected. In each case, the permeability dropped to almost zero, and recovered gradually to less than 10^{-3} μm^2 (1 millidarcy). The gradual increase in permeability after injection of the third slug is shown in Figure 5 (curve B). After eight days, the foam was broken by a slug of 0.09 PV foam breaker, as described in a later section.

In two additional experiments, foam was formed by injection of gas at constant rate, one in 1.3 μm^2 (1300-millidarcy) Boise sandstone and the other in 0.19 μm^2 (190-millidarcy) Berea sandstone. Data from these experiments are plotted as curves C and D in Figure 5. The general similarity of all the curves in Figure 5 indicates that under foamed conditions the permeability to gas in a 0.19 μm^2 core was similar to that in a 1.3 μm^2 core. The degree of permeability reduction was less in the lower permeability core, a phenomenon that was also observed by Bernard and Holm (1964).

Liquid Blocking by Foam in Sandstone Cores at High Pressure

Besides blocking gas flow, foam also blocks liquid flow, as first observed by Bernard, Holm, and Jacobs (1965). This property could be used to prevent upward coning of water into a withdrawal well. In low-permeability reservoirs, the pressure at the withdrawal well must be reduced much below the reservoir pressure to induce sufficient flow to the well. This local reduced pressure causes water to rise in a cone and to increase the liquid saturation near the withdrawal well perforations. Two-phase flow in the well results, with greatly reduced gas productivity. A strategically placed foam lens would reduce the permeability to water near the withdrawal well, thereby delaying water coning and extending the seasonal life of the withdrawal well.

In an experiment to measure the ability of foam to block liquid flow, foam was formed by injecting gas and liquid simultaneously into the 1.3 μm^2 (1300 millidarcy) Boise sandstone core. Then the injection of gas was stopped, and liquid saturation and pressure profiles were measured while the injection of liquid (foamer solution, later changed to surfactant-free brine) was continued. Figure 8 shows the liquid saturation at 20 and 50 cm in the core during this experiment, and Figure 9 shows the liquid permeability calculated between pairs of adjacent pressure taps. First, 9.5 pore volumes (based on the total pore volume of the core) liquid were pumped through the core. Because the liquid saturation in the core was approximately 35%, this was sufficient to replace the liquid in the core 28 times. During this part of the experiment, the liquid permeability throughout the core remained at 10^{-3} μm^2 (1 millidarcy), and the liquid saturation remained at 35% throughout the core. These values agree with the relative permeability data measured for the same core using brine and nitrogen gas (for relative permeability data see Persoff et al. 1989). Then the liquid was changed from foamer solution to brine without surfactant, and another 17 pore volumes (sufficient to replace the liquid in the core 51 times) were pumped through the core. Bubbles emerging from the exit of the back pressure regulator showed that lamellae broke and some of the trapped gas was

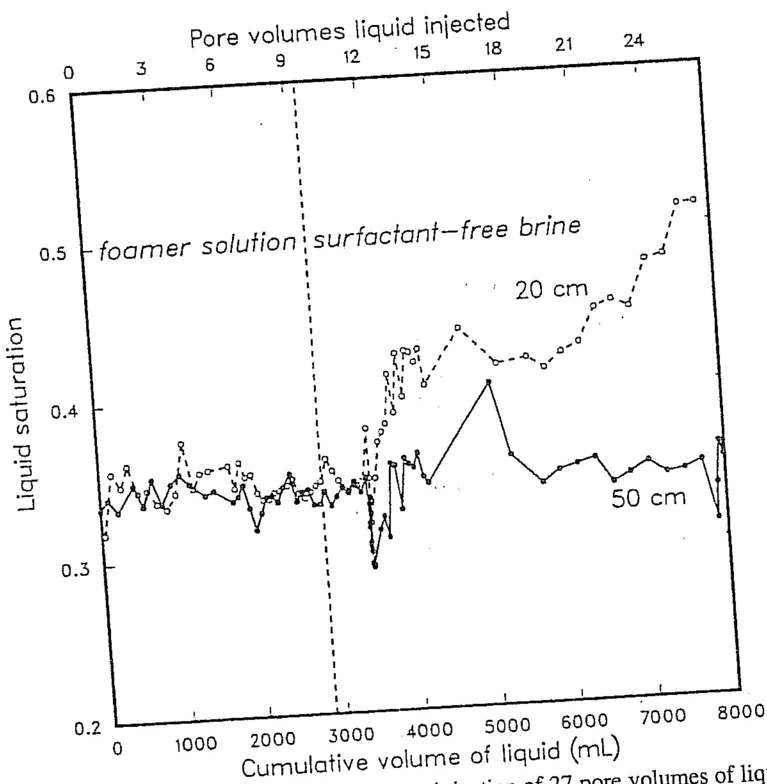

Figure 8. Liquid saturation at 20 and 50 cm during injection of 27 pore volumes of liquid through a foam-filled Boise sandstone core.

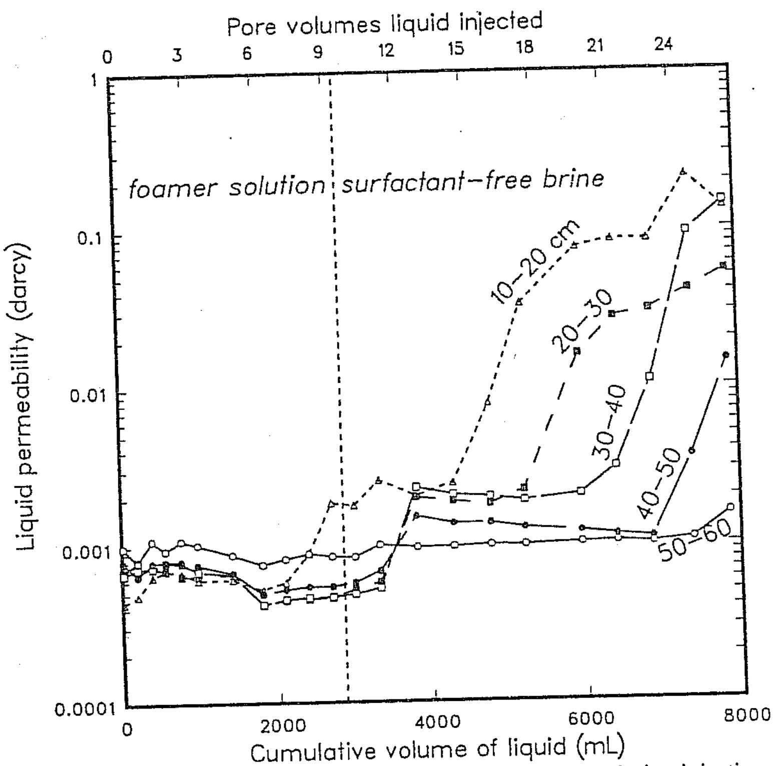

Figure 9. Liquid permeability between pairs of adjacent pressure taps during injection of 27 pore volumes of liquid through a foam-filled Boise sandstone core.

released, and Figures 8 and 9 show that both the liquid saturation and the liquid permeability increased as the surfactant was diluted in the foam, starting at the core inlet and progressing to the outlet. This agrees with the accepted view that low liquid permeability in a foamed core results from low liquid saturation (Bernard et al. 1965; Persoff et al. 1989).

The results of the liquid-blocking experiment indicate that the key to controlling water coning into gas withdrawal wells is keeping the liquid saturation, and the vertical liquid permeability, at a low value in the region around the wellbore. Many foam-flow experiments reported here and elsewhere (Persoff et al. 1989) show that the liquid saturation in a foam-filled core is just a few units above connate, and the relative permeability to liquid is typically about 10^{-3}. This experiment demonstrated that water saturation in a foam-filled porous medium remains low even though a large gradient of water pressure is imposed across it. This suggests that water coning could be controlled by strategically placing a foam lens near the gas-water contact so as to block the upward flow of water. Figure 10 shows schematically the use of such a lens to block coning of water.

A three-phase gas storage reservoir simulator, MULKOM-GWF, developed for this project (Pruess and Wu 1988) was used to study the effectiveness of a foam lens in preventing coning and to optimize its placement. The parameters used in the simulation study are presented in Table 1. This study concluded that the effect of a low-permeability zone created by foam near a wellbore is not to prevent coning, but to diminish and delay it significantly. Because gas withdrawal is limited to a few months of the year, permanent

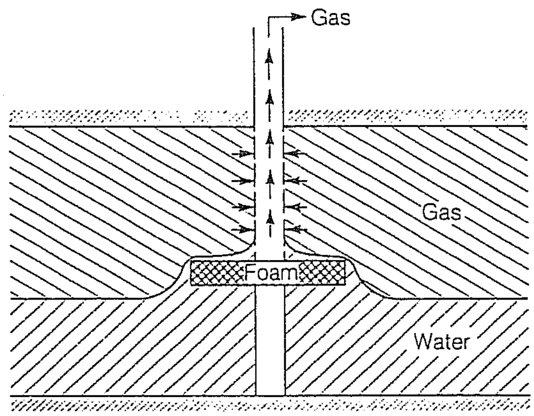

Figure 10. Use of a horizontal foam lens to reduce water coning, schematic.

prevention of coning is not necessary. Figure 11 shows the calculated water production rates for a gas-withdrawal well. A foam lens placed 5 m above the gas-water contact appears sufficient to delay water coning for three months, which is a substantial improvement in the seasonal life of a withdrawal well. This application of foam appears quite promising in its economics, because the advantage may be obtained by placement of a relatively small volume of foam without additional drilling.

Controlled Breakage of Foam

As part of this investigation we also demonstrated that a foam block could be broken by injection of isopropanol. Intentional breaking of a foam block might be desired if foam has been formed in a location where it interferes with gas injection or withdrawal. Iso-

Table 1
Parameters for Numerical Simulation of Water Coning

Permeability (isotropic)	$3.7 \times 10^{-2} \mu m^2$ (37 millidarcy)
Permeability of foamed region	$3.7 \times 10^{-4} \mu m^2$ (0.37 millidarcy)
Dimensions of foam lens:	
height	5 m (16.4 ft)
diameter	30.5 m (100 ft)
Porosity	10%
Irreducible water saturation	20%
Irreducible gas saturation	45%
Temperature	31°C
Gas production rate	1.42×10^8 standard L/day (5×10^6 standard ft^3/day)
Perforated interval	20 m (65.6 ft)
Initial gas/water contact below reservoir top	30 m (98.4 ft)
Pressure at GWC	9.38 MPa (1360 psi)
Gas saturation at GWC	51%

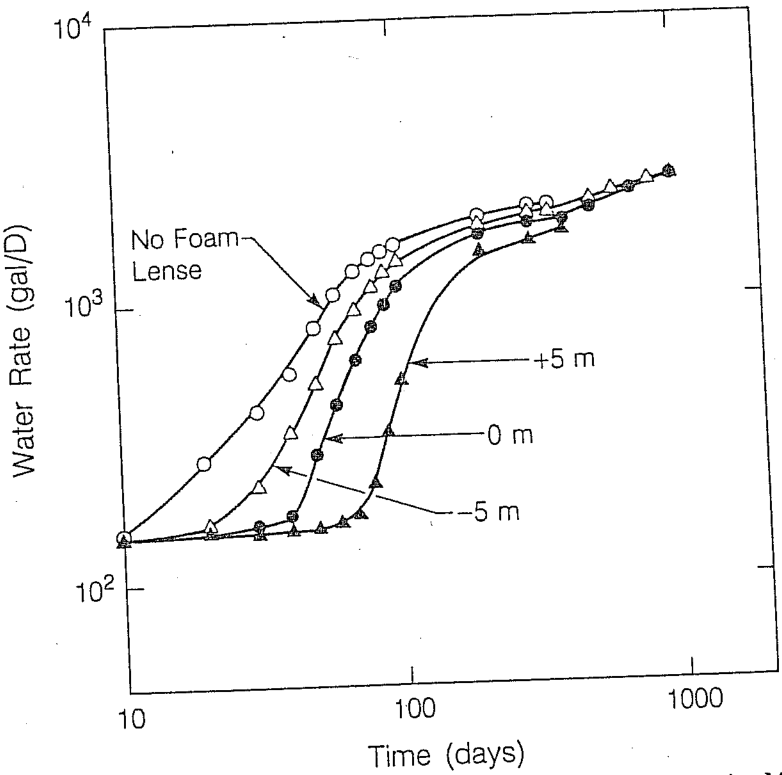

Figure 11. Numerical simulation of water production in a gas withdrawal well, using MULKOM-GWF. The parameters are listed in Table 1. Four cases are simulated; no foam lens; foam lens located at the gas-water contact; and 5 m above and below the gas-water contact. Emplacing the foam lens just above the gas-water contact provides the greatest protection against water coning.

propanol is known to break foam, and we routinely flushed cores with technical-grade isopropanol to break foam between experiments. We prepared a solution of 50 wt% isopropanol in brine for a foam-breaking demonstration following the foam-regeneration experiment. After foam had been formed and observed for eight days, a slug of 0.09 PV (sufficient to replace one-third of the liquid in the core) of foam breaker was injected into the core at a rate slow enough not to stop the gas flow into the core. The pressure and liquid saturation were monitored while gas continued to flow into the core. Figure 12 shows the pressure profiles measured during injection of the next pore volume of gas. The flat pressure gradient in the inlet region shows that the foam was broken and gas mobility restored where foam breaker displaced the foamer solution. It is clear that isopropanol is an effective foam breaker, should one be needed.

Discussion

The technical issues to be resolved for foam application in aquifer gas storage are whether foam can be formed and emplaced in a formation, whether it will sufficiently reduce gas or liquid permeability, and whether the reduced permeability can be maintained for months. Our experiments, although not answering all the questions, have given

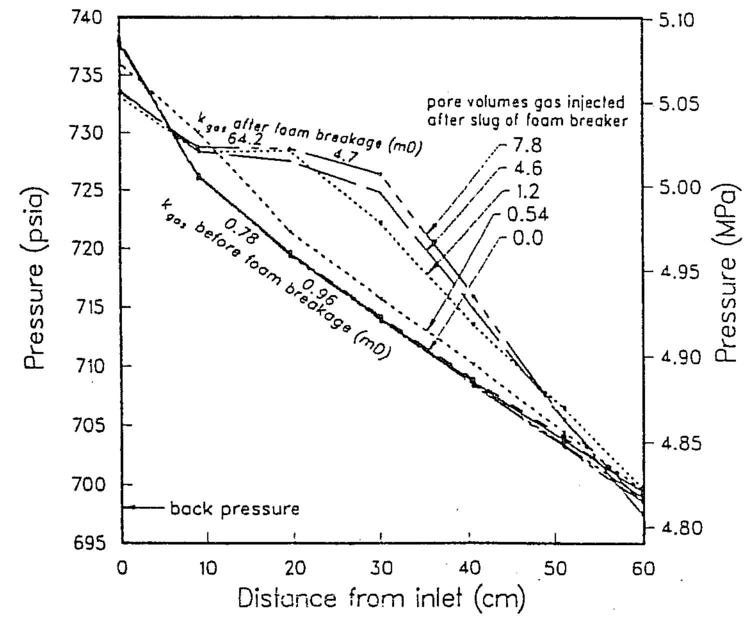

Figure 12. Increase in gas permeability, showing breakage of foam following injection of a 50 wt% isopropanol solution.

favorable results to suggest that foam can be applied to increase the efficiency of underground gas storage.

The theoretical arguments and experiments of Ransohoff and Radke (1988) indicate that there is a critical gas velocity that must be exceeded for generation of a strong foam. Lamellae are formed when gas invades individual liquid-filled pores, so the critical velocity presumably refers to the gas pore velocity, which is always greater than the superficial velocity. The difference between the two velocities may be large because the porosity and gas saturation are both less than unity, and some or most of the gas in the core may be trapped and immobile. We have not determined the critical pore velocity in our experiments, except to observe that it was exceeded in one-dimensional experiments when the superficial gas velocity was 1 m/day.

If foam is to be formed by injecting gas from a well in radial flow, the superficial gas velocity, and likely also the gas pore velocity, will decrease at large distances from the well. This may limit the distance at which foam can be generated in situ. Therefore, better definition and measurement of the critical velocity is needed. In any case, generation of foam near a wellbore is certainly feasible.

The question of emplacement is essentially a question of how far gas can be injected above the critical velocity without exceeding the allowable injection pressure. The gas permeability of a foam-filled formation, the allowable injection pressure, the critical velocity for snap-off, and the viscosity of the liquid phase all combine to set a limit on the distance to which foam can be driven in situ. Spacing the foam bank away from the wellbore reduces the injection pressure, but also makes it more difficult to regenerate. Note also that as gas displaces liquid, the liquid is driven ahead of the foam, and its pressure drop must be added to the pressure drop through the foam. If a polymer is used in the liquid, this could also become significant.

Although one-dimensional laboratory experiments in homogeneous media have shown large reductions in gas and liquid permeability, it is necessary to determine whether this degree of permeability reduction can be achieved in the field. Radial flow may cause gas velocities to be too slow to form a strong foam at distances from the wellbore, and natural heterogeneity may interfere with emplacement of a foam bank.

The results shown in Figure 5 suggest that for a gas-blocking application, some provision must be made to regenerate the foam. The cost of the project will depend upon the needed frequency of regeneration. Additional slugs of liquid would be injected whenever the permeability of the foam block exceeds a certain limit, and the higher this limit is set, the less frequently regeneration would be needed. But even if the foam were allowed to decay, the gas saturation in the designated storage volume would be greater and more uniform than if foam had not been used, so improved recoverability of injected gas should result.

The rate of foam decay shown in Figure 5 is likely pessimistic due to the test method. The gas injected in all these experiments was dry, and liquid saturations below connate measured during the later stages of each experiment near the inlet region indicate that liquid was removed from the core by evaporation. Low liquid saturation is known to be detrimental to foam stability (Khatib, Hirasaki, and Falls 1988). The method used to conduct the experiment is therefore a severe test of foam block durability. The observation that inclusion of guar in the foamer solution increased the durability of the blocked condition might be explained by more stable lamellae being formed or by higher liquid saturation in those experiments due to greater viscosity of the displaced liquid.

Pilot-scale field testing is now needed to confirm these results in practice. The most promising application for a field trial appears to be control of water coning. Such a field trial could be done at a well where coning has been experienced in the past (the control experiment has already been done), and the former solution could be injected through the existing well and followed with gas. Another attractive prospect for a field trial would be the use of foam to seal a known leakage path of limited area, such as a fault zone or casing leak.

Application of foam to underground gas storage need not be limited to conventional underground storage in aquifers. Where demand is present but suitable geologic formations are absent, mined caverns in hard rock could be used as storage reservoirs. Here leakage through fractures intersecting the cavern might be controlled by foam. Another area where foam technology could be applied is compressed-air energy storage in aquifers. By controlling gas migration and water coning, foam could prevent leak-off of pressure and loss of stored energy and could ensure deliverability. Because the cycle in pressure in this application would be daily, rather than annual, requirements for foam stability might be reduced.

Conclusions

The results of our experiments with a linear anionic ethoxysulfate foamer solution, stabilized by a linear alcohol, support the following conclusions:

(1) Foam reduces the gas permeability of sandpacks and sandstones by two or three orders of magnitude. The permeability gradually increases as lamellae decay, but foam can be regenerated by injection of additional slugs of foamer solution.

(2) Inclusion of 0.5 wt% guar in the foamer solution appears to enhance the stability of a foam block in a sandpack.

(3) The pressure drop in foam flow through sandstone varies directly with the liquid flow

rate. Therefore, when injection pressure must be limited, the most effective way to form a foam bank is to saturate the formation with surfactant solution and then inject gas. Alternating slugs of surfactant solution may be used to make a stronger foam.

(4) Foam effectively blocks liquid flow because the liquid saturation is low. When liquid is pumped through a foam-filled core, the liquid saturation remains low as long as the surfactant concentration is not diluted. When the surfactant concentration is diluted, trapped gas is released, and liquid saturation and liquid permeability increase. In our experiment, approximately 17 pore volumes of water were pumped through the core before the permeability increased significantly.

(5) The most effective location for placement of a foam bank to prevent water coning is just above the gas-water contact.

(6) Formation of a foam bank spaced away from an injection well may be feasible by injecting foamer solution, displacing it with brine, and then injecting gas. The location of the foam bank reflects displacement by both the brine and injected gas.

(7) Foam was broken, and gas permeability restored, by injection of a 50 wt% isopropanol solution.

Based on the results of our experimental and theoretical studies, we conclude that application of foam to improve the efficiency of aquifer gas storage appears to be technically feasible. The logical next step is a field trial. The most promising field trial would be an attempt to control water coning by means of a relatively small foam lens emplaced beneath the feed zone of a gas withdrawal well.

Acknowledgment

This work was supported by the Gas Research Institute, Chicago, IL, under Contract No. 5086-271-1160, through U.S. Department of Energy Contract No. DE-AC03-76SF00098. This paper was originally presented at the 1989 International Gas Research Conference, Tokyo.

References

Bernard G.G., and L.W. Holm. 1964. Effect of foam on permeability of porous media to gas. *Soc. Petrol. Eng. J.* (September):267–274.

Bernard, G.G., L.W. Holm, and W.L. Jacobs. 1965. Effect of foam on trapped gas saturation and on permeability of porous media to water. *Soc. Petrol. Eng. J.* (December):295–300.

Bond, D.C., and G.G. Bernard. 1967. Forming foam under reservoir conditions in petroleum recovery process. United States Patent No. 3,318,379, May 9.

Hanssen, J.E. 1988. A new method for testing of gas-blocking foams. Paper SPE/DOE 17362, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, OK, April 17–20.

Khatib, Z.I., G.J. Hirasaki, and A.H. Falls. 1988. Effects of capillary pressure on coalescence and phase mobilities in foams flowing through porous media. *SPE Reservoir Eng.* 3 (September):267–274.

Minssieux, L. 1974. Oil displacement by foams in relation to their physical properties in porous media. *J. Petrol. Technol.* (January):100–108.

Persoff, P., C.J. Radke, K. Pruess, S.M. Benson, and P.A. Witherspoon. (in press). A laboratory investigation of foam flow in sandstone at elevated pressure. Paper presented at 1989 California Regional SPE Meeting, Bakersfield, CA, April 5–7, (SPE-18781). To appear in *SPE Reservoir Eng.*

Pruess K., and Y.S. Wu. 1988. On PVT—data, well treatment and preparation of input data for an isothermal gas-water-foam version of MULKOM. Report LBL-25783, prepared for Gas Research Institute under Contract No. 5086-271-1160, Lawrence Berkeley Laboratory.

Ransohoff,T.C. and C.J. Radke. 1988. Mechanism of foam generation on glass-bead packs. *SPE Reservoir Eng*. 3(2):573–585.

Roof, J.G. 1970. Snap-off of oil droplets in water-wet pores. *Soc. Petrol. Eng. J.* (March 1970):85–90; *Trans. AIME*, 249:85–90.

Witherspoon, P.A., C.J. Radke, Y. Shikari, K. Pruess, P. Persoff, S.M. Benson, and Y.S. Wu. 1987. Feasibility analysis and development of foam-protected underground natural gas storage facility. (LBL-23500). American Gas Association, Proceedings Operating Section, Paper #87-DT-110, 539–549.