Abstract
Steam injection has had a profound impact on the production of heavy crude oil. Steam, however, is inviscid compared to a viscous oil and is not the ideal displacement agent. Field studies and laboratory tests have shown that foaming the steam phase through the aid of a suitable surfactant in aqueous solution can achieve mobility control of injected gases and mitigate the effects of gravity override. Thus, production is improved. Unfortunately, simulation models and simulation tools that accurately gauge the effects of foam on gas mobility in porous media are not readily available.

Recent advances in modeling gas mobility in the presence of foam are reviewed. These include the so-called bubble population balance method, scaling arguments to obtain representative foam texture and hence gas mobility, and semi-empirical alteration of gas mobility. The bubble population balance is then illustrated by means of a few sample calculations.

Introduction
Field application of foam is becoming a proven technology, surfactant costs withstanding, to control the mobility of gaseous phases in porous media. Typical applications span from steam\textsuperscript{1,4} and CO\textsubscript{2} foam\textsuperscript{5} to alleviate gravity override and channeling, production well treatments to reduce gas-oil ratio (GOR)\textsuperscript{6,7}, to gelled-foams\textsuperscript{8} for long-lasting plugging of high permeability channels. Foam processes have also been studied and field tested for use as groundwater aquifer clean up methods\textsuperscript{9,11}.

To date, there have been about 25 major steam-foam projects implemented\textsuperscript{12}. The attributes of fields subjected to foam are varied. Fields range from thick, steeply dipping sands where the objective is to improve vertical sweep, to flat, moderately thick reservoirs where gravity override is a concern, to improving injection profiles in layered reservoirs so that steam is injected into unheated zones. Foams are also useful to improve the distribution of heat during steam soaks.

With this considerable body of field knowledge in regard to steam foam, it would seem that we should be able to chose and evaluate candidate fields effectively. However, the highly nonlinear flow properties of foam in porous media and the widely varying chemistry of surfactants with respect to temperature and sensitivity to oil make generalizations difficult. Thus, more efficient application of foam EOR processes, especially steam-foam, would result from a comprehensive model of the process. In particular, a mechanistic model would expedite scale-up of the process from the laboratory to the field and the extrapolation of results from one field to another.

Foams in Porous Media
It is widely accepted that foam bubble size controls the mobility of foam in porous media\textsuperscript{13}. Finely textured foams (small bubble size) are much less mobile than coarsely textured foams (large bubble size). It is also well known that foam flow behavior is strictly non-Newtonian\textsuperscript{13,14}. In order to understand the phenomena that a foam simulator must be capable of reproducing, the configuration of foam within rock pore space and the pore-level events that alter the size and shape of bubbles are discussed briefly.

Figure 1 depicts schematically a picture of the pore-level distribution of foam that has emerged from micromodel observations, pore-level modeling, and core floods\textsuperscript{14,17}. In this highly schematic picture, sand
grains are cross-hatched. For illustrative purposes only, the largest channels lie at the middle of the figure whereas the smallest lie at the bottom. Wetting surfactant solution is denoted as the dotted phase. Foam bubbles are either unshaded or darkly shaded, depending upon whether they are stationary or flowing.

Due to strong capillary forces, wetting liquid occupies the smallest pore spaces and clings to the surface of sand grains as wetting films. The aqueous, wetting phase maintains continuity throughout the pore structure shown in Fig. 1 so that the aqueous-phase relative permeability function is unchanged in the presence of foam18,23. Minimal volumes of liquid transport as lamellae. Unshaded flowing foam transports as trains of bubbles through the largest and least resistive flow channels. Because the smallest pore channels are occupied solely by wetting liquid and the largest pore channels carry flowing foam, significant bubble trapping occurs in the intermediate-sized pores.

Bubble volumes are roughly the same as individual pore volumes, or larger, and lamellae span across pore cross sections completely. This configuration is denoted a confined foam, as opposed to a bulk foam17. This terminology acknowledges the role of the porous medium in confining foam configuration and shaping bubbles.

Foam reduces gas mobility by decreasing gas relative permeability and increasing gas effective viscosity. Stationary or trapped foam blocks a large number of channels that otherwise carry gas. Gas tracer studies measure the fraction of gas trapped within a foam at steady state in sandstones to lie between 85 and 99%15,24. Bubble trains within the fraction that does flow encounter drag because of the presence of pore walls and constrictions25, and because the gas/liquid interfacial area of a flowing foam bubble is constantly rearranged by viscous and capillary forces13.

Bubble and trains of bubbles are in a constant state of rearrangement. Bubbles and lamella transport some distance, are destroyed, and then regenerated. Further, trains halt when the local pressure gradient is insufficient to keep them mobilized, and other trains then begin to flow.

Foam texture arises from a balance between varied and complicated foam generation and destruction mechanisms. Regardless of whether foam bubbles are generated in situ or externally, they are molded and shaped by the porous medium14,16. Foam generation is largely a mechanical process, and it is sensibly independent of the type of surfactant. Bubbles are created by snap-off and division at germination sites that are a function of pore geometry of fluid occupancy. Surfactant stabilizes the gas/liquid interface of foam bubbles and prevents coalescence. Hence, foamer concentration and formulation affect the rate of foam coalescence.

The interaction of foam bubbles and oil is also important to gas mobility. Some foams are stable in the presence of oil while others are not. Sensitivity to the presence of oil increases foam coalescence. Thus, foam bubble size increases, and subsequently the foam mobility increases also. While there is no general agreement and a theory consistent with all observations of stability, foam stability in the presence of oil does appear to correlate with the oil entering coefficient26. That is, if oil can enter the gas-surfactant solution interface the oil can destabilize the foam.

More thorough reviews of foam generation, coalescence, and transport on the pore level are given by Chambers and Radke16 and Kovscek and Radke17.

**Simulator Attributes**

It is unlikely that any simulation approach/simulator can reproduce all observations of foam phenomena. It is also not necessary that a process simulation model be mechanistic in order to be successful. However, there are certain attributes that appear to be important for successful foam modeling on the reservoir scale:

- Gas mobility must be reduced in the presence of foam. In a simulation approach, this may be accomplished by reducing the gas relative permeability, increasing the gas viscosity, or a combination of both.
- Computed foam mobilities should incorporate some notion of non-Newtonian foam flow behavior because flow rates vary between the well-bore region and deep in the reservoir. Moderate to finely textured foams are decidedly shear thinning.
- Foam properties vary with surfactant concentration and must be modeled. Likewise foam stability in the presence of oil varies with surfactant type and must be modeled.
- Surfactant transport, partitioning, and adsorption must be accommodated accurately.
- The method should be predictive rather than merely history matching.

In summary, foam properties vary with space and time, and must be modeled accordingly. Likewise, surfactant/brine transport must be modeled in some fashion.

**Foam Flow Simulation Methods**

A variety of methods have been proposed to incorporate foam into reservoir simulators. They range from empirical and semi-empirical alteration of gas mobility to population balance methods. We discuss the methods and the simulators that result.
**Empirical Methods.** Perhaps the simplest means of including the effects of foam in a simulator is through the use of a constant mobility reduction factor, MRF. That is, the gas relative permeability is divided by a constant value

\[ k_{rf}(S_g) = \frac{k_{rg}(S_g)}{1 + MRF} \]  

(1)

If the foam is very strong, the MRF is very large, and vice versa. To account for surfactant transport, a concentration threshold must be exceeded before the gas mobility is modified. Such a model has been employed in UTCHEM\textsuperscript{10,11}, a chemical flood simulator developed at the University of Texas at Austin.

The weakness in employing a constant MRF is that it varies with gas velocity, surfactant concentration, and the presence of oil. Furthermore, it is difficult to predict a single MRF that will describe an experiment or a field situation from first principles.

Another application of the mobility reduction factor concept is to tabulate MRF as a function of surfactant concentration, water and oil saturations, pressure, and gas velocity. The MRF appropriate to any condition is then found via table lookup. This is a flexible way to extend reservoir simulation to foam flow and could be applied to any variable that is found to influence foam generation and transport. Of course laboratory experiments or history-matching field results is necessary to obtain the relevant tabular data. Extrapolation outside the range of tabulation is also difficult.

This approach has been applied to ECLIPSE 200 (Geoquest). Unfortunately, the implementation is at odds with the physics of surfactant transport. Because foam affects gas-phase properties, surfactant is assumed to be a tracer in the gas-phase even though it is a solute dissolved in the aqueous phase. Simulating surfactant transport correctly is a key to simulating transient foam processes. It is not clear how this aphysical assumption changes the predictive capabilities of the simulator.

**Semi-Empirical Methods.** A variety of techniques have been proposed for the semi-empirical alteration of gas mobility. Most have focused on modifying gas relative permeability, but gas-phase effective viscosity has been modified also. The essence of semi-empirical methods of foam simulation is to assign a functional form to the MRF. The form is based on experiments, field results, and conjecture.

The popularity of this method is, apparently, an outgrowth of the success with which results from the Kern River steam-foam pilots\textsuperscript{3} were simulated. Patzek and Myhill used field and laboratory results to calibrate a model of performance in the Mecca pilot and then predicted the incremental oil recovery from the Bishop pilot without adjusting parameters\textsuperscript{27}. Essentially, their simulator tracks the surfactant chemical species and accounts for surfactant partitioning from the aqueous phase. The surfactant partition coefficients adjusted so that the simulated surfactant propagation rate is equal to the pilot foam propagation rate. It is assumed that foam exists whenever steam and aqueous surfactant are present in a grid block. The mobility reduction factor is an increasing function of aqueous surfactant concentration. Patzek and Myhill state that the model was coded into a predecessor of THERM (Scientific Software Intercomp), and it was never released generally.

The semi-empirical approach to foam modeling has also been used in STARS (Computer Modeling Group)\textsuperscript{2,28}. Surfactant transport, adsorption, partitioning, and degradation are modeled rigorously. Foam is represented via Eq. (1) with explicit surfactant concentration, oil saturation, and gas velocity dependencies for MRF:

\[ MRF = M \left( \frac{w_s}{w_f} \right)^{e_w} \left( \frac{S_o - S_o}{S_o} \right)^{e_o} \left( \frac{N_c}{N^*} \right)^{e_v} \]  

(2)

In Eq. (2), \( w_s \) is the aqueous concentration of surfactant, \( S_o \) is the oil saturation, \( e \) are exponents, superscripts \( m \) refer to reference or maximum values of variables, and \( N_c \) is a capillary number

\[ N_c = \frac{Kp}{\sigma} \]  

(3)

Here, \( K \) is the permeability, \( p \) the pressure, and \( \sigma \) the vapor/surfactant solution interfacial tension.

This formulation accounts for effects on performance due to surfactant concentration, the presence of oil, and via the capillary number portion, velocity effects on the mobility of foam. Interestingly, no liquid velocity dependence on MRF is shown in Eq. (2) nor is there a term for the effect of capillary pressure. Laboratory experiments have shown that these variables play an important role in foam performance. Presumably, Eq. (3) could be modified by including factors for liquid velocity and capillary pressure.

A partially mechanistic formulation based on the concept of a limiting capillary pressure for foam flow has also been proposed and incorporated into UTCOMP\textsuperscript{29,30}. UTCOMP is a compositional simulator developed at the University of Texas at Austin. Essentially, if surfactant is present and capillary pressure is low, gas mobility is made small via a reduced gas relative permeability. There is no velocity
dependence to the mobility reduction.

An alternative to modifying the gas-phase relative permeability is to employ an effective viscosity of the gas phase and thereby reduce gas-phase mobility when foam is present. Marfroe et al\textsuperscript{31} employ such an approach with a relatively simple function of surfactant concentration, aqueous-phase saturation, and gas-phase velocity. Implicit in this formulation is that changes in foam bubble size, and thus mobility, correlate with foamed gas velocity and how far the porous medium is from irreducible water saturation.

A similar approach with a more complicated effective viscosity function including permeability and oil saturation has also been implemented\textsuperscript{32}. It is postulated that foam effective viscosity varies according to

$$
\mu_f = \mu_g \left[ 1 + D_f (n_f S_w - S_{w,0}) f_k(k) + f_p(V_p) \right] \left[ 1 + E \frac{S_f}{S_g} \right]
$$

(4)

where \( \mu \) is the viscosity, the subscripts \( f \) and \( g \) refer to foam and free gas, respectively, \( f_k \) is a function of surfactant concentration, \( S_{w,0} \) is the irreducible water saturation, \( f_p \) is a function of absolute permeability, and \( D_f \) and \( E \) are adjustable constants. In addition, it is assumed that the relative permeabilities of all phases are unique functions of the saturation of each phase. Strong foams that are effective in the presence of oil would have a large \( D_f \) and a small \( E \). The various functions are determined by history matching and experimental observations.

**Mechanistic Models.** To date mechanistic models for foam simulation have lead to population balance approaches where the average number of foam bubbles per unit volume is tracked\textsuperscript{24,33,34}. This balance is analogous to the usual mass and energy balances that comprise a simulator. Bubble texture is then used to predict foam mobility. For example, a conservation balance is written for the average concentration of bubbles

$$
\frac{\partial}{\partial t} \left[ \phi (S_f n_f + S_t n_t) + \nabla \cdot (u_f n_f) \right] = \phi S_g (r_f - r_c)
$$

(5)

where \( \phi \) is the porosity, \( S \) is saturation, \( n \) is bubble density or texture, \( u_f \) is the flowing foam velocity, and the subscripts \( f, t, \) and \( g \) refer to flowing foam, trapped foam, and gas, respectively. The total gas saturation is the sum of flowing and stationary portions. Hence, \( S_g = S_f + S_t \). The first term on the left is the net change in foam texture, whereas the second is the convection rate of foam bubbles. On the right hand side, \( r_f \) and \( r_c \) are the foam generation and coalescence rates on a per volume of gas basis, respectively. Specific formulations for \( r_f \) and \( r_c \) are available in the literature\textsuperscript{17,24,33,34}. These terms are important for they determine bubble texture, and through texture, gas mobility.

In addition to kinetic expressions for bubble generation and destruction, the conservation equations require flow rate relationships for each phase. For the flowing foam, the structure of Darcy’s law is retained

$$
u_f = \frac{-K k_f}{\mu_f} \nabla p_g
$$

(6)

\( k_f \) is the relative permeability to foam and \( \mu_f \) is the foam effective viscosity. Although Eq. (6) is in the form of Darcy’s law, it does not imply Darcy flow because foam effective viscosity is non-Newtonian.

In most population-balance formulations, foam effective viscosity is expressed as

$$
\mu_f = \mu_g + \frac{a n_f}{\nu_f}
$$

(7)

where \( a \) is a proportionality constant, \( \nu_f = u_f / \phi S_g \) is the foam interstitial velocity, and the theoretically based value of the exponent is 1/3. The validity of Eq. (7) is supported by the analysis of bubble flow in tubes.

Gas mobility in porous media in the presence of foam is also reduced by trapped foam blocking an appreciable amount of the pore space. This effect is usually incorporated through the relative permeability function. The clearest method of incorporating trapped gas saturation via relative permeability is to recognize that flowing foam selectively partitions to the largest pores and to adopt a "Stone-type" relative permeability model\textsuperscript{17}. Hence, the flowing foam relative permeability is a function only of \( S_f \). Finally, a constitutive equation is needed to predict the fraction of gas that actually flows\textsuperscript{24,34}.

The strength of this approach is that a framework is provided to express numerically all of the relevant physics regarding foam flow. To date, a fully mechanistic, population-balance based simulator has not been available. However, Chevron did, apparently, use a proprietary population-balance based simulator to predict and evaluate the performance of a steam-foam pilot\textsuperscript{12,36}. Additionally, it has been reported recently that the population balance equation was incorporated into a compositional, thermal reservoir simulator and the method was illustrated with sample calculations \textsuperscript{37}. The simulator was called FOAM3D to illustrate its multidimensional capabilities.

A criticism of mechanistic, continuum approaches to foam simulation is that they require many variables and
parameters. For example, the population balance approach of Kovscek et al.\textsuperscript{17,34} employs 10 parameters in addition to the usual parameters describing multiphase flow. For comparison, the semi-empirical approach illustrated in Eq. (2) has seven adjustable parameters, whereas the semiempirical adjustment of foam effective viscosity given in Eq. (4) has two unknown parameters and three functions that remain to be specified. The advantage of the mechanistic approach is that most of these foam parameters have clear physical meaning and their values are set \textit{a priori}.

**Example Calculations**

The implementation in STARS of semi-empirical reduction of gas mobility in the presence of foam has been illustrated in several papers\textsuperscript{2,28,38}. Hence, no calculations are reported here. We do note that these authors report generally good performance of the simulator in regard to capturing features of foam performance in the field.

A simple example is used here to illustrate the application of the population balance method to field-scale, multidimensional reservoir simulation. Foam is injected into one-quarter of a confined five-spot pattern with 2.5 acre spacing. Hence, injector-to-producer spacing is 72 m (235 ft) and we simulate converging-diverging flow. The formation is assumed to be 20 m thick, have a homogeneous permeability of 1.3 d, a constant porosity of 0.25, and impermeable upper and lower boundaries. The system is specified to be isothermal, and air and foamer solution are injected simultaneously into the layer which is originally filled with brine. The injection well is partially completed across the lower 1/8 of the interval, whereas the production well is completed across the entire interval and maintained at a pressure of 4.8 MPa (700 psi). Injection rates for N\textsubscript{2} and aqueous solution are 15.5 and 0.85 m\textsuperscript{3}/d, respectively. The injection rates are such that the foam quality is roughly 95%. See ref\textsuperscript{37} for more details.

To provide contrast with the highly efficient foam displacement to follow, simulations of unfoamed gas injection were completed first. Gas saturation contours in the vertical cross section are presented in Fig. 2 at 50, 100, 200 and 300 d. The gray-scale shading indicates the gas saturation. Unshaded portions of the graph refer to an S\textsubscript{g} of zero, and progressively darker shading corresponds to larger S\textsubscript{g}. Areas contacted by gas are poorly swept. Buoyancy quickly drives injected gas to the top of the formation, a gas tongue forms, and gas breakthrough at the producer occurs quite quickly.

After breakthrough, little desaturation occurs because pressure gradients are low and buoyancy prevents gas from contacting areas along the lower horizontal boundary. This is classical gravity override.

With simultaneous injection of N\textsubscript{2} and foamer solution, foam generates where surfactant and gas are present, and the results are dramatically different. Figures 3, 4, and 5 present S\textsubscript{g}, n\textsubscript{f}, and C\textsubscript{s}, profiles respectively, in the vertical cross section at times of 50, 100, 200, and 300 days. In Fig. 3, the gas saturation contours indicate that both a strong displacement by foam is occurring and a weak displacement by the unfoamed gas ahead of the foam front. Near the injector, the high gas saturation region associated with the foamed gas assumes a semi-spherical shape. The contours at later times in Fig. 4 illustrate that spherical growth and efficient displacement continue. The darkly shaded region immediately below the upper impermeable boundary indicates a tongue of unfoamed gas that forms due to gravity override.

Figure 5 illustrates foam texture as a function of time. The foamed regions correspond exactly with zones of high gas saturation. The bubble textures associated with black shading are 100 mm\textsuperscript{3}, and the light-gray shading at the foam front is roughly 20 mm\textsuperscript{3}. The most finely textured foams are found adjacent to the well bore where gas and liquid flow velocities are largest.

Interestingly, both Figs. 3 and 4 indicate a spherical zone of foam growth. A similar trend has been observed in the field. Specifically, compare to Fig. 14 of Ref.\textsuperscript{27}.

The most provocative result of this simulation is found in Fig. 5: surfactant is actually lifted in the formation above its injection point. Black shading indicates a concentration of 0.83 wt%. Foamed gas effectively desaturates the zone around the injector. Although the aqueous-phase relative permeability function is unchanged in the presence of foam, the low S\textsubscript{w} results in low relative permeability and highly resistive flow for the aqueous phase. The flow of surfactant-laden water is rerouted and surfactant is pushed upward in the formation. In this example, gravity override has been effectively negated.

When foam reaches the upper boundary of the layer, displacement continues from left to right in the horizontal direction in a piston-like fashion that expels the resident liquid phase. Propagation is slow until the flow begins to converge.

**Summary**

A brief review of the physics of foam generation and flow in porous media was given in order to rationalize the attributes of a simulator that are necessary for successful calculation of foam flow on the reservoir-scale. Methods for predicting foam flow that have been incorporated into reservoir simulators were then discussed along with some limitations of each method.
Nomenclature

\[ c = \text{exponent in foam effective viscosity} \]
\[ e = \text{exponent in expression for MRF} \]
\[ k_r = \text{relative permeability} \]
\[ K = \text{permeability} \]
\[ M = \text{constant in expression for MRF} \]
\[ MRF = \text{mobility reduction factor} \]
\[ N_e = \text{capillary number} \]
\[ n = \text{number density of foam} \]
\[ p = \text{pressure} \]
\[ r = \text{rate of foam generation/coalescence} \]
\[ S = \text{saturation} \]
\[ v = \text{interstitial velocity} \]
\[ w_s = \text{surfactant concentration} \]

Greek Letters

\[ \alpha = \text{proportionality constant for foam effective viscosity} \]
\[ \phi = \text{porosity} \]
\[ \mu = \text{viscosity} \]
\[ \sigma = \text{surface tension} \]

Subscripts and Superscripts

\[ c = \text{coalescence rate} \]
\[ f = \text{flowing foam} \]
\[ g = \text{gas} \]
\[ g = \text{generation rate} \]
\[ m = \text{maximum} \]
\[ o = \text{oil} \]
\[ s = \text{surfactant} \]
\[ t = \text{trapped foam} \]
\[ v = \text{velocity} \]

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References

Fig. 1: Pore-level schematic of a flowing foam.

Fig. 2: Gas saturation profiles for unfoamed gas injection into a confined 5 spot.

Fig. 3: Gas saturation profiles for the simultaneous injection of gas and foamer solution into a confined 5 spot.
Fig. 4: Foam texture profiles for the simultaneous injection of gas and foamer solution into a confined 5 spot.

Fig. 5: Surfactant concentration profiles for the simultaneous injection of gas and foamer solution into a confined 5 spot.