

Estimation of Parameters for the Simulation of Foam Flow through Porous Media. Part 1: The Dry-Out Effect

Kun Ma, Jose L. Lopez-Salinas, Maura C. Puerto, Clarence A. Miller, Sibani Lisa Biswal, and George J. Hirasaki*

Department of Chemical and Biomolecular Engineering, Rice University, Houston, Texas 77005, United States

ABSTRACT: We develop a method of estimating foam simulation parameters from laboratory experiments. Gas and surfactant solution are coinjected into sand packs at different experimental conditions in two systems. At steady state, saturation of the aqueous phase is shown to be relatively constant over a wide range of foam qualities. In order to obtain an accurate model fit at the transition foam quality, the difference between the foam model parameter $fmdry$ and the transition water saturation S_w^t is identified and a method to precisely calculate S_w^t is developed. By superimposing contour plots of the transition foam quality and the foam apparent viscosity, one can estimate the reference mobility reduction factor ($fmmob$) and the critical water saturation ($fmdry$) using the STARS foam model. The parameter $epdry$, which regulates the abruptness of the foam dry-out effect, can be estimated by a transient (continuous gas injection) foam experiment.

1. INTRODUCTION

Foam in porous media is defined as a dispersion of gas in liquid such that the liquid phase is continuous and at least some part of the gas phase is made discontinuous by thin liquid films called lamellae.¹ Although these lamellae are thermodynamically unstable, they can be in situ generated in porous media via various mechanisms.² This fact leads to a dynamic balance of liquid lamellae and effective foam propagation through underground formations. Using surfactants as foaming agents to stabilize foams is an effective way to generate strong foams in porous media.³ These surfactant-stabilized foams were employed as displacing fluids to enhance oil recovery (EOR) in oil reservoirs^{4–6} and to improve sweep efficiency in environmental remediation processes.^{7,8} For example, as mobility control agents, CO₂ foams have been successfully tested in the laboratory^{9–12} and through several pilots in the United States.¹³ Currently miscible CO₂-EOR processes are tested in heterogeneous carbonate oil reservoirs in Abu Dhabi, UAE,^{14,15} and CO₂ foams may also be applicable to enhance sweep efficiency in these reservoirs. Without the use of foams, poor sweep efficiency is caused by low viscosity of CO₂ and heterogeneous conditions between reservoir layers as well as in matrix/fracture systems.¹⁶

Foam reduces the gas mobility by reducing the gas relative permeability (k_{rg}) and increases the effective viscosity of the gas phase (μ_g).¹⁷ The mechanism behind this gas relative permeability reduction is the effect of trapped-gas saturation created by foam.^{18,19} For continuous-gas foams, the reduction of gas relative permeability is the only effect of foam. However, for discontinuous-gas foams, the flow resistance of lamellae contributes to an increase in the apparent viscosity of foam (defined in section 2.1.1).²⁰ Depending on the foaming agent, the apparent viscosity of surfactant-stabilized foams can be as high as several hundred centipoise,²¹ which is orders of magnitude higher than the viscosity of either gas or water.

In addition to mobility reduction of the gas phase, several important properties of foam transport in porous media have

been discovered by a number of researchers. One finding is that there exists a minimum pressure gradient (∇p_{min}) or a critical injection velocity in a certain porous medium to generate strong foam.^{3,22} Trapped bubbles are mobilized above this pressure gradient, and one flowing lamella divides into two lamellae upon a branch point in the flowing channels. The division of liquid lamellae refines foam texture and generates strong foam, and lamellae division does not happen without a sufficient pressure gradient.²³ The minimum pressure gradient is dependent on the permeability of the system, and low permeable porous media generally requires high ∇p_{min} to generate strong foam.³

Another important finding is the understanding of the limiting capillary pressure (P_c^*) for foam stability.²⁴ When conditions are favorable for generation of finer textured foam, the resulting gas mobility reduction decreases the water saturation, which increases the capillary pressure until the rate of foam coalescence equals foam generation. Meanwhile, typical pressure gradient contours of foam flooding indicate that two regimes exist in which foam flows through porous media: the low-quality regime and the high-quality regime.²⁵ In the low-quality regime, where the water fractional flow is high, bubble trapping and mobilization dominate the foam flow;²⁶ in the high-quality regime, gas bubbles are separated by thin liquid lamellae resulting in a relatively dry foam and its behavior is determined by the limiting capillary pressure and bubble coalescence.^{24,27} These two foam regimes can be visualized in micromodel experiments, and the lamellae-separated foam shows a significantly improved sweep in the heterogeneous porous media compared with 100% gas injection.²⁸

Various foam models have been proposed to simulate foam flow through porous media, among which the most promising ones are the mechanistic methods based on bubble population

Received: May 10, 2012

Revised: April 16, 2013

Published: May 3, 2013

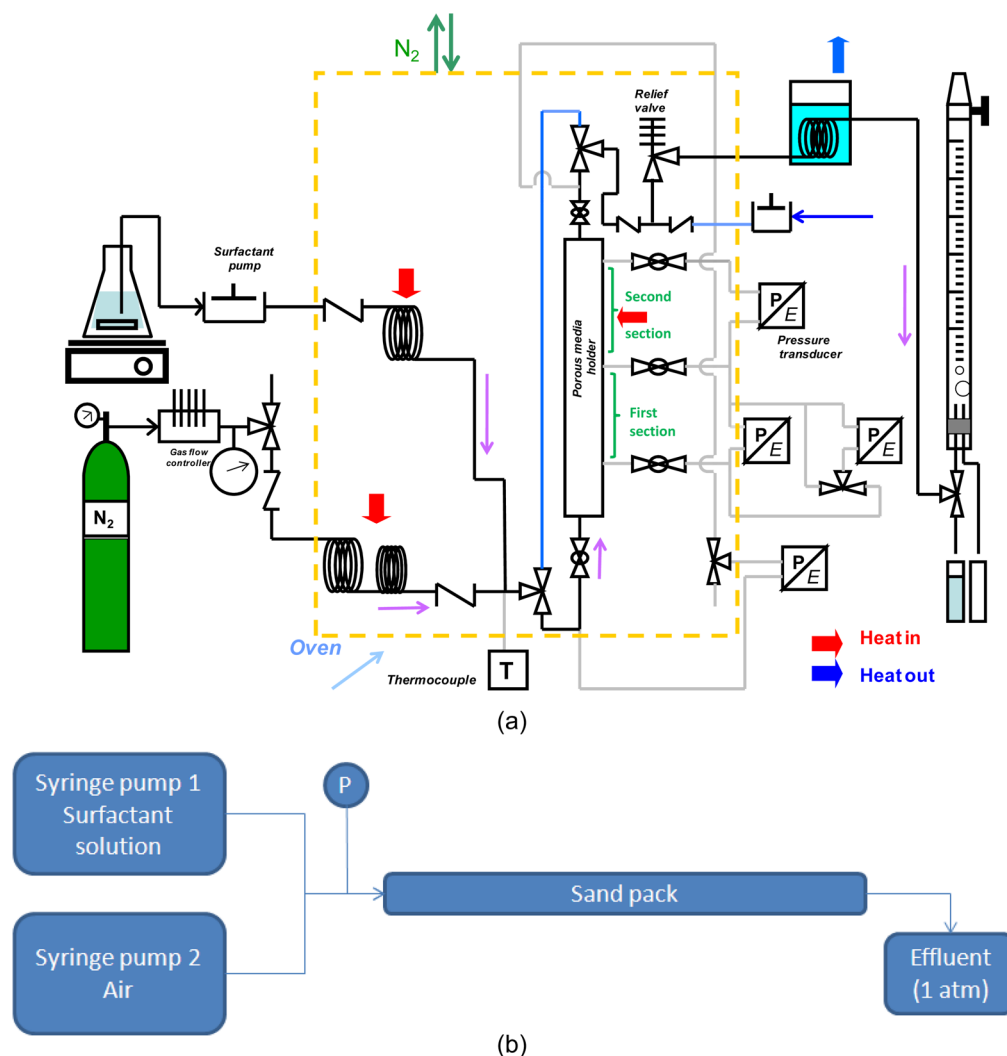


Figure 1. Schematic of the apparatus for foam experiments in (a) system A and (b) system B.

balance and the local-equilibrium methods. The population-balance foam model is a mechanistic method to describe foam flow through porous media.^{18,29–33} It has received wide attention because it physically describes the generation and decay of foam lamellae and dynamically tracks the mobility of foam. In this model, foam texture (the number of liquid lamellae per unit volume present in porous media) is modeled explicitly with a bubble population-balance equation and gas mobility is expressed as a function of foam texture, water saturation, and other factors.³⁴ This foam model has successfully matched several laboratory experiments^{30,33,35} and is capable of simulating foam behavior in both the high-quality and low-quality regimes upon the modification of net foam generation.^{36–38} However, there are some limitations in this foam model, such as the difficulty in obtaining the modeling parameters, especially at the field scale, and determining the minimum pressure gradient for foam generation.³⁴

In the early studies of the local-equilibrium methods, the effect of foam on gas mobility reduction is expressed with a mobility reduction factor (MRF), which reduces the relative permeability of the gas phase depending on surfactant concentration, oil saturation, and capillary number.³⁹ Advances to these local-equilibrium methods incorporate the mechanistic physics of foam coalescence to the MRF. According to the

fixed- P^* model,⁴⁰ the effect of limiting capillary pressure above which foam collapses is included in the foam model in terms of a critical water saturation. This concept was later adopted in a commercial reservoir simulator STARS with a modified expression.⁴¹ Vassenden and Holt proposed a similar model by modifying the gas relative permeability with experimental validation.⁴² On the other hand, lamella creation and coalescence are balanced by assuming local steady state, and a model modifying gas phase viscosity through foam texture is constructed.^{37,38} In this model, foam texture is a function of water saturation and pressure gradient if the water saturation is above the critical water saturation. According to Darcy's law, decreasing the relative permeability or increasing the viscosity of the gas phase by the same factor results in the same mathematical expression. Therefore, it does not make a difference if a viscosity-based model versus a relative-permeability-based model (STARS) is utilized. The local-equilibrium foam model using the fractional flow theory,⁴¹ or the STARS foam model,⁴³ has been widely used to describe foam flow through porous media in the oil and gas industry. These applications include simulation of surfactant-alternating-gas (SAG) processes⁴⁴ and simultaneous injection of surfactant solution and gas,^{45,46} simulation of foam flow in the matrix in naturally fractured reservoirs,¹⁶ simulation of oil displacement

by foam,^{47–49} interpretation of experimental data of coinjection of gas and surfactant solution on the 10 m scale⁵⁰ and in Berea cores,⁵¹ and simulation of the foam process at the reservoir scale from the Snorre field in Norway.^{52,53}

A crucial step for simulating foam flow through oil reservoirs is to estimate the parameters used in the foam model. Because there are many parameters in the STARS model, it is important to develop a strategy for quickly estimating them before running the reservoir simulations. In this work (part 1 of this series of papers), we perform an experimental study of foam flow through porous media and present a feasible way to estimate the parameters in the dry-out function in the STARS foam model. Specifically, a hybrid contour plot method with the aid of MATLAB is introduced for a process of two-parameter estimation to model the effect of gas fractional flow on foam apparent viscosity. Additionally, we propose that the parameter μ_{foam} in the dry-out function can be estimated through a transient experiment in which 100% gas displaces surfactant solution at 100% initial water saturation. In part 2 of this series of papers, we investigate the nonuniqueness, parameter sensitivity and numerical artifacts in foam modeling;⁵⁴ in part 3 of this series of papers, we will present the foam modeling techniques by combining the dry-out effect with the velocity effect as well as the surfactant concentration effect.

2. MATERIALS AND METHODS

2.1. Experimental Setup. Systems A and B as shown in Figure 1, respectively, are used to collect data in 1-D foam flooding processes. We describe system A and system B separately in sections 2.1.1 and 2.1.2.

2.1.1. System A. A proprietary surfactant blend ZAC (code name Z-R₁₁-ZFG₁₂ + A-R₁-AFG + C-R₃-CFG₃) is used as the foaming agent in system A. The ZAC blend with 0.1 wt % total surfactant concentration in synthetic brine is used in all experiments with system A. The synthetic brine contains 27.0 g/L NaCl, 1.3 g/L CaCl₂, 11.2 g/L MgCl₂·6H₂O, and 4.8 g/L Na₂SO₄. All aqueous solutions are prepared with DI water (resistivity 18.2 MΩ cm) and 30 ppm of Na₂SO₃ as an oxygen scavenger.

The foam experiments are done at 94 °C in the setup shown in Figure 1a. Prepurified nitrogen gas is injected to the oven controlling the flow rate through a gas flow controller. Check valves are located before and after a heat exchanger located inside the oven. The surfactant solution is continuously mixed and filtered in the suction of a HPLC pump, then passes through a check valve at the inlet of a heat exchanger. The surfactant solution is mixed in a cross with nitrogen then injected to the sand pack. The mixture of nitrogen and surfactant solutions are fed into the packed 20–40 mesh silica sand column (i.d. = 2.29 cm, L = 38.1 cm, k = 100 darcy, 20/40 Ottawa Silica Sand U.S.-Silica) from the bottom at a total injected superficial velocity ($u_w + u_g$) of 33 ft/day (2.7 cm³/min). Three internal taps are located at different heights to measure pressure drops across the packed column every 6 in.; the effluent passes through a check valve and mixed with a small continuous flow of water delivered by an ISCO pump set at less than 0.1 cm³/min. This auxiliary pump maintains a continuous injection of water for keeping the relief valve open, acting as a back pressure regulator. Keeping the valve open minimizes the pressure oscillations caused by two-phase flow in experiments. The relief valve is set up to open in the pressure of 30 ± 0.2 psig, and this is the back pressure used during experiments for system A. This setup back pressure will depend on the desired conditions of the experiment and to prevent flashing of any component within the liquid blends. In other words, back-pressure is kept constant by a special arrangement even during more than one-phase flow, where a small amount of water is constantly injected to keep flow-control open all the time. The outlet of the relief valve is conducted to a condenser. The cooled effluent is collected in vials. The liquid–gas ratio is measured when desired by flipping a 3-

way valve into an inverted buret. The history of the pressure at different times during the experiments is recorded.

The foam apparent viscosity, which is the pressure gradient normalized with respect to the permeability and the total flux of surfactant solution and gas, is calculated through eq 1:

$$\mu_{\text{foam,app}} = \frac{-k \nabla p}{u_w + u_g} \quad (1)$$

There are other forms of foam apparent viscosity in the literature, such as the one using gas superficial velocity in the denominator.⁵⁵ It should not matter in the parameter estimation process which form of foam apparent viscosity is used. The reason this form is chosen is because the proposed approach is consistent with the method using the contour plot of the pressure gradient⁴¹ since a fixed total flow rate is used in our experiments.

2.1.2. System B. An internal olefin sulfonate, IOS1518, is used as the foaming surfactant in the foam flooding experiments in system B. This product was manufactured by Stepan (19.42 wt % activity, lot no. 18239-032708) with a trade name of Petrostep S-2A. Silica sand 20/40 (U.S. Silica Company) is used to pack the porous media in the 1-D glass column (30010 Glass Pipe Conical, Scientific Glass and Instruments Inc.). The sand pack has a diameter of 2.58 cm and a length of 27.5 cm. A permeability of 158.0 darcy and a porosity of 36.0% are determined for this system.

In system B, the water saturation in porous media is measured by weighing the sand pack using a balance (Sartorius Balance BP 3100S) after all valves are closed and the sand pack is separated from other equipment. Zero water saturation corresponds to the weight of a fresh sand pack before water injection; 100% water saturation corresponds to the weight of a water-saturated sand pack after water injection to the system which was previously filled with CO₂. By excluding the dead volume (1.5 mL), a linear relationship between the water saturation and the weight of the sand pack is employed to determine the water saturation at a specific weight. After this calibration, surfactant solutions are used as the aqueous phase in foam experiments other than water. The density difference between the surfactant solution (1.016 g/mL) and water (0.997 g/mL) is used to calculate the aqueous phase saturation based on the method described above.

The sand pack is filled with DI water before the foam generation experiment. IOS1518 with a final concentration of 0.2 wt % is dissolved in 1.0 wt % NaCl brine. Surfactant solution (2.0 PV) is injected to the porous media to satisfy the surfactant adsorption. A series of steady-state coinjection experiments start from 99% air injection displacing surfactant solution and end up with 10% air injection. The experimental setup of system B is shown in Figure 1b. Surfactant solution is coinjected with air to the sand pack using syringe pumps (Harvard Apparatus model 22) at a total superficial velocity ($u_w + u_g$) of 20 ft/day. Because of the lack of internal taps in the glass sand-pack holder, a pressure transducer (Validyne Engineering model DP7) is located at the inflow end, and it is assumed to be measuring the pressure drop across the porous media. The outflow end is open to the atmosphere. When a steady state is achieved and the pressure drop reaches a plateau value, the pressure drop is averaged over the period of the steady state.

A transient (continuous gas injection) experiment, shown in Figure 16 in this work, is performed using the same sand pack and a mass flow meter (Matheson model 8200) to control the flow rate of the injected gas phase. After saturated with DI water, the sand pack is placed vertically and 4.0 PV of 0.2 wt % IOS1518 in 1.0 wt % NaCl is injected from bottom to top to displace the DI water. Then the sand pack is placed horizontally to allow N₂ injection to the system. The flow rate of N₂ is 20 ft/day in standard conditions (or 2.212 sccm).

2.2. Foam Model. The STARS foam model (2007 version^{16,43}) is employed in this work. This foam model assumes local steady state, which means that foam creation and decay mechanisms occur relatively fast compared with flow through porous media.⁴⁴ On the basis of the reported literature, the STARS foam model is shown in eqs 2 and 3:^{47,48}

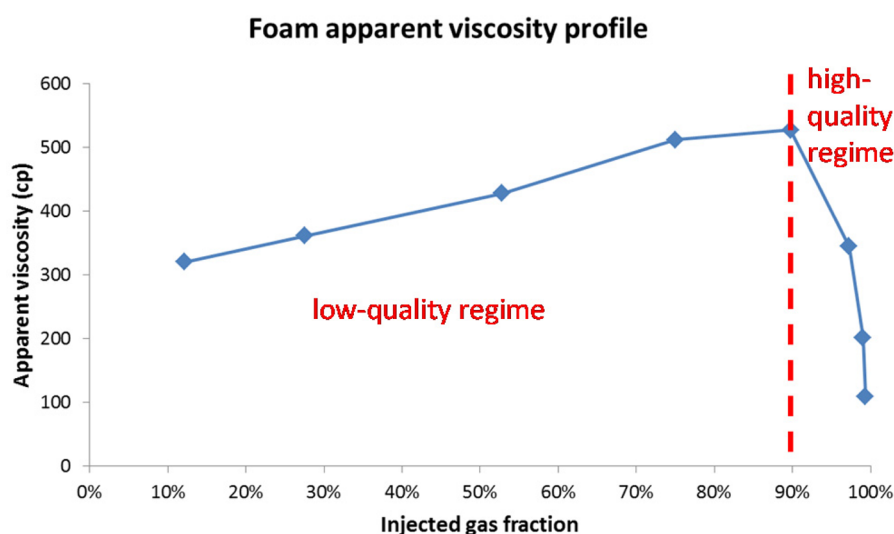


Figure 2. Effect of foam quality on foam apparent viscosity in system A. The total superficial velocity is 33 ft/day.

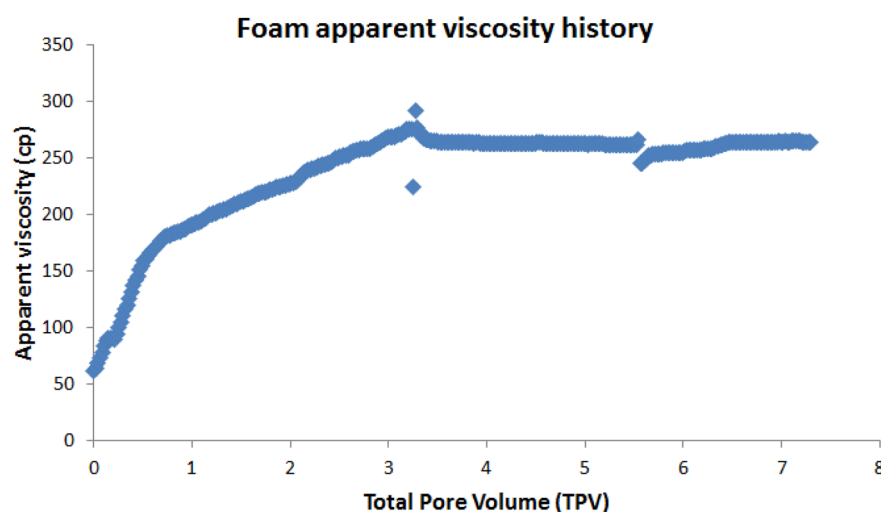


Figure 3. Typical foam apparent viscosity history of coinjection experiments in system B. The total superficial velocity is 20 ft/day with an injected gas fraction of 70%.

$$k_{rg}^f = k_{rg}^{nf} \times FM \quad (2)$$

$$FM = \frac{1}{1 + fmmob \times F_1 \times F_2 \times F_3 \times F_4 \times F_5 \times F_6} \quad (3)$$

Equations 2 and 3 indicate that this foam model uses a mobility reduction factor called FM to change the relative permeability of the gas phase in the presence of foam. The mobility reduction factor FM includes six functions (F_1 to F_6 , subscripts corresponding to different functions may vary in different versions) to describe different factors on gas mobility reduction. In this work, we mainly focus on estimating the parameters in the function F_2 (water-saturation-dependent function) shown in eq 4.

$$F_2 = 0.5 + \frac{\arctan[\text{epdry}(S_w - \text{fmdry})]}{\pi} \quad (4)$$

The details of the functions, F_1 (surfactant-concentration-dependent function), F_3 (oil-saturation-dependent function), F_4 (shear-thinning function), F_5 (critical-capillary-number-dependent function), and F_6 (salinity-dependent function) can be found elsewhere^{16,43} and are not discussed here. The experiments disclosed in this paper are performed at a fixed total superficial velocity, and we assume no shear-thinning effect in the foam model. The combination of the shear-

thinning effect and the dry-out effect will be discussed in part 3 of this series of papers in the future.

3. RESULTS AND DISCUSSION

3.1. Experimental Results of Foam Flooding.

3.1.1. Foam Experiments in System A. A set of steady-state foam experiments is conducted at a total superficial velocity of 33 ft/day in system A. The effect of foam quality (gas fractional flow) on foam apparent viscosity is shown in Figure 2. We observe two distinctive foam regimes in Figure 2: the high-quality (high-gas-fractional-flow) regime and the low-quality (low-gas-fractional-flow) regime.^{25,27} The foam apparent viscosity increases when the injected gas fraction increases in the low-quality regime and decreases when the injected gas fraction increases in the high-quality regime. At the boundary of the two regimes, foam obtains its maximum apparent viscosity at a given surfactant concentration and total superficial velocity. The gas fractional flow at the boundary of these two regimes is known as the transition foam quality.²⁷ The data points in Figure 2 show a transition foam quality at 90% gas injection with a maximum foam apparent viscosity of 527 cP.

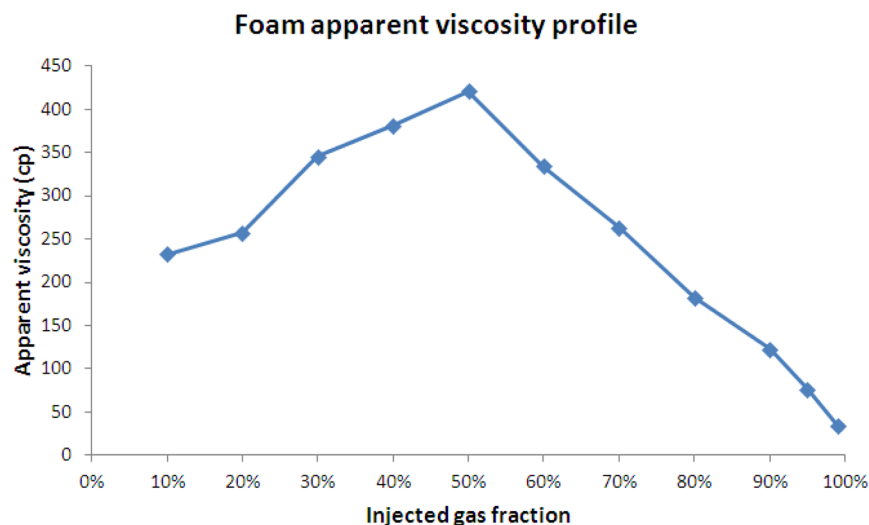


Figure 4. Effect of foam quality on foam apparent viscosity in system B. The total superficial velocity is 20 ft/day.

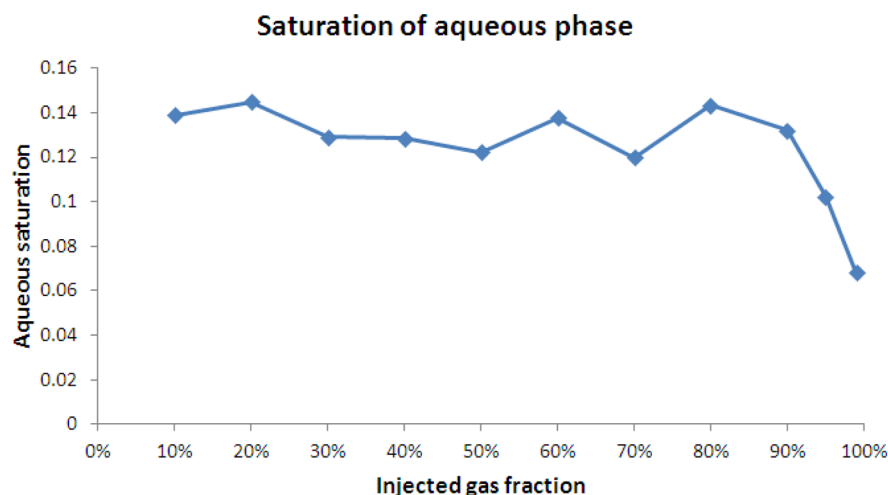


Figure 5. Effect of foam quality on aqueous saturation in system B. The total superficial velocity is 20 ft/day.

3.1.2. Foam Experiments in System B. Figure 3 is for depicting a typical foam apparent viscosity history of our coinjection experiments in system B. The total superficial velocity is 20 ft/day with an injected gas fraction of 70%. The pressure drop in the system is recorded every 30 s. The foam apparent viscosity reaches a steady state after about 3.5 TPV. The sudden pressure changes at 3.3 and 5.6 TPV are due to the operation of refilling injectants. The steady-state foam apparent viscosity (263 cP) for 70% gas injection is obtained by averaging the plateau viscosities.

The effect of foam quality on foam apparent viscosity in system B is shown in Figure 4. In this system, the transition foam apparent viscosity is 421 cP with a pressure difference of 7.59 psi across the sand pack. The transition foam quality in system A (90%) is much higher than the one in system B (50%). It was shown that the transition foam quality is a function of core permeability, surfactant type, surfactant concentration, and overall flow rates.²⁷ The results presented here indicate that the transition foam quality strongly depends on the surfactant formulation in geometrically similar porous media, which adds further confirmation to the point made in the literature.²⁷

The effect of foam quality (f_g) on the saturation of aqueous phase (S_w) is shown in Figure 5. Typical fraction flow curves show that higher f_g (or lower f_w) results in lower S_w in the absence of foam. The effect of f_g on S_w in the presence of foam is investigated in system B within the range of f_g from 10% to 99%, and it is found that S_w is relatively constant over a wide range of foam qualities.

3.2. Foam Modeling Results with the Dry-out Function. 3.2.1. *Distinction between S_w^f and f_{mdry} .* By assuming incompressible, isothermal flow and the absence of capillary pressure and using 1-D Darcy's law we have

$$u_w = \frac{-kk_{rw} \nabla p}{\mu_w} \quad (5)$$

$$u_g = \frac{-kk_{rg}^f \nabla p}{\mu_g} \quad (6)$$

Combined with eq 1 we obtain

$$\mu_{foam,app} = \frac{k \nabla p}{\frac{kk_{rw} \nabla p}{\mu_w} + \frac{kk_{rg}^f \nabla p}{\mu_g}} = \frac{1}{\frac{k_{rw}(S_w)}{\mu_w} + \frac{k_{rg}^f(S_g)}{\mu_g}} \quad (7)$$

Note that the compressibility of the gas phase affects flow rates of gas, which leads to the fact that the upstream foam quality is less than that downstream in 1-D steady-state experiments. The superficial velocity is not constant even though the mass flux is constant at steady state. If the average foam quality is used instead of the injected foam quality, the transition foam quality will become larger. The experimental data and model fit shown in this paper are based on the injected foam quality without being adjusted for compressibility. Meanwhile, the relative permeability is a function of saturation, and in two-phase flow we have

$$S_w + S_g = 1 \quad (8)$$

$$k_{rw} = k_{rw}^0 \left(\frac{S_w - S_{wc}}{1 - S_{gr} - S_{wc}} \right)^{n_w} \quad (9)$$

$$k_{rg}^f = k_{rg}^0 \left(1 - \frac{S_w - S_{wc}}{1 - S_{gr} - S_{wc}} \right)^{n_g} \frac{1}{1 + f_{mob} \times F_2} \quad (10)$$

Here the function F_2 is described in eq 4. According to eqs 7–10, $\mu_{foam,app}$ is a function of S_w when other parameters are fixed.

In order to calculate the gas fractional flow from eqs 5 and 6, we have

$$f_g = \frac{u_g}{u_w + u_g} = \frac{1}{1 + \frac{k_{rw}(S_w)}{\mu_w} \frac{\mu_g^f}{k_{rg}^f(S_g)}} \quad (11)$$

Therefore, in a two-phase system f_g is also a function of S_w only if other parameters stay unchanged. Through eqs 7 and 11, one can calculate $\mu_{foam,app}$ and f_g as functions of S_w .

We define $\mu_{foam,app}^t$ as the transition foam apparent viscosity between the high-quality and low-quality foam regimes. $\mu_{foam,app}^t$ is also the maximum foam apparent viscosity if the foam quality varies and the total flow rate is fixed. We define the water saturation at which $\mu_{foam,app}^t$ is obtained through eq 7 as the transition water saturation (S_w^t), and the gas fractional flow calculated at the transition water saturation with eq 11 as the transition foam quality (f_g^t). The transition foam quality was also used in the literature with a symbol of f_g^* , and the corresponding water saturation was S_w^* .⁴¹ If $epdry$ is sufficiently large, S_w^* , S_w^t , and the foam modeling parameter $fmdry$ approach each other.⁴¹ In this section, we show the distinction between S_w^t and $fmdry$ if a relatively small value of $epdry$ is used. A small value of $epdry$ indicates a gradual transition between the high-quality and low-quality foam regimes.

An example case is discussed below for matching the experimental data in system A. With a set of foam modeling parameters ($epdry = 500$, $f_{mob} = 33\,000$, and $fmdry = 0.0730$), $\mu_{foam,app}$ vs S_w is shown in Figure 6 using the rest of the parameters for system A in Table 1. Unless otherwise specified, a preset value (500) of $epdry$ is used to perform the steady-state model fit in this work. The choice of $epdry$ and the effect of $epdry$ on foam modeling are discussed in section 3.2.4. A connate water saturation (S_{wc}) of 0.07 is used as shown in Table 1. S_{wc} can be estimated by matching experimentally measured water saturation for system B, which is discussed in section 3.2.3.

The parameters in relative permeability curves in Table 1 are obtained from the literature for unconsolidated sandpacks.³⁴ These parameters are selected to demonstrate how to estimate

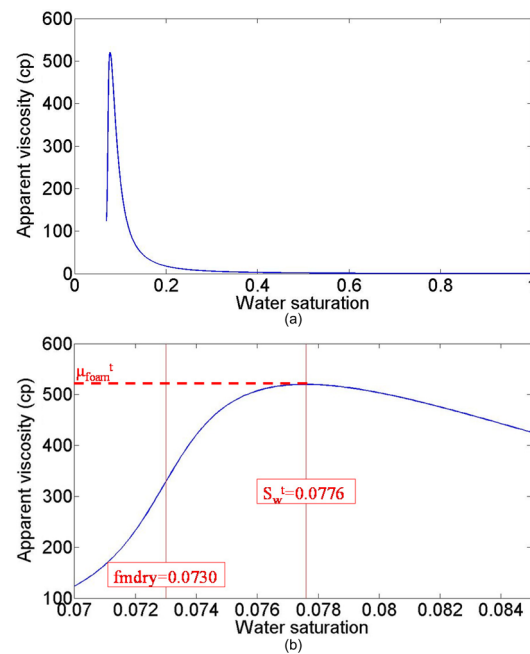


Figure 6. Foam apparent viscosity as a function of water saturation using $f_{mob} = 33\,000$ and $fmdry = 0.0730$: (a) full profile and (b) close-up profile near $fmdry$. The rest of the parameters used are shown in Table 1 (system A) with a preset $epdry$ of 500.

Table 1. Parameters for Foam Modeling in This Work

parameter	value	ref
$epdry$	500	
S_{wc}	0.07	
S_{gr}	0	34
μ_w (cp) (system A)	0.3	56
μ_w (cp) (system B)	1.0	56
μ_g (cp) (system A and B)	0.02	57
k_{rw}^0	0.79	34
k_{rg}^0	1.0	34
n_w	1.96	34
n_g	2.29	34

foam parameters in the dry-out function. Foam parameters are sensitive to the parameters in relative permeability curves, especially the exponent in the k_{rw} curve. The sensitivity of foam modeling parameters to the parameters in relative permeability curves was discussed in part 2⁵⁴ of this series of papers.

There exists a maximum foam apparent viscosity ($\mu_{foam,app}^t$) with changing foam qualities in Figure 6, which corresponds to the transition water saturation (S_w^t) and the transition foam quality (f_g^t). However, S_w^t is not equivalent to the parameter $fmdry$, which is designed to be the critical water saturation (the dry-out function F_2 in eq 4 is equal to 0.5 when $S_w = fmdry$) in the STARS foam model⁴¹ as indicated in Figure 6b. In the case of $f_{mob} = 33\,000$ and $fmdry = 0.0730$, we obtain $S_w^t = 0.0776$ through a 1-D golden section search function “ $fminbnd$ ” in MATLAB.⁵⁸

Despite the small difference between $fmdry$ and S_w^t in this example, assuming S_w^t to be equal to $fmdry$ can cause significant error in calculating the transition foam quality f_g^t as shown in Figure 7b. This is due to the fact that the $f_g - S_w$ curve is steep near $S_w = fmdry$ for describing the effect of the limiting capillary pressure (Figure 7). Therefore, S_w^t needs to be calculated using

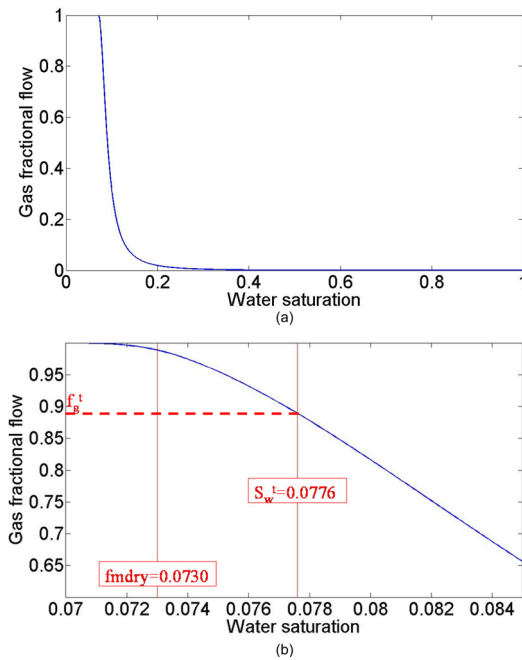


Figure 7. Gas fractional flow as a function of water saturation using $f_{mob} = 33\,000$ and $f_{mdry} = 0.0730$: (a) full profile and (b) close-up profile near f_{mdry} . The rest of the parameters are used as shown in Table 1 (system A) with a preset $epdry$ of 500.

the algorithm instead of being assumed to be the parameter f_{mdry} especially when a relatively small value of $epdry$ is used.

3.2.2. Hybrid Contour Plot Method. Cheng and co-workers⁴¹ showed how to fit the parameters to steady-state laboratory coreflood data using the STARS foam model. This method is based on the hypothesis that the experimental ∇p data is vertical in the high-quality regime and horizontal in the low-quality regime in order to draw the contours of ∇p to fit the model parameters. The shape of the discontinuous slope between vertical and horizontal lines, as a result of the abrupt change in gas mobility as a function of S_w , can cause numerical

oscillation in finite difference simulation. The details of this numerical oscillation were investigated in part 2⁵⁴ of this series of papers.

We propose an alternative approach for fitting experimental data by fixing total velocity of both gas and liquid and changing gas fractional flow. This approach estimates the parameters f_{mob} and f_{mdry} by matching the transition foam apparent viscosity ($\mu_{foam,app}^t$) at the transition foam quality (f_g^t) in this set of experimental data. The parameter $epdry$ is estimated by examining the fit to the rest of the steady-state data and the transient experiment with continuous gas injection.

In this section we introduce a hybrid contour plot method to estimate the parameters f_{mob} and f_{mdry} in steady-state experiments. The procedure tackles three equations with three unknown variables: S_w^t , f_{mob} , and f_{mdry} :

$$\mu_{foam,app}(S_w^t, f_{mob}, f_{mdry}) = \max_{S_w} \mu_{foam,app}(S_w, f_{mob}, f_{mdry}) \quad (12)$$

$$\mu_{foam,app}^t = \frac{1}{\frac{k_{rw}(S_w^t)}{\mu_w} + \frac{k_{rg}^f(S_w^t, f_{mob}, f_{mdry})}{\mu_g}} \quad (13)$$

$$f_g^t = \frac{1}{1 + \frac{k_{rw}(S_w^t)}{\mu_w} \cdot \frac{\mu_g}{k_{rg}^f(S_w^t, f_{mob}, f_{mdry})}} \quad (14)$$

Note that the explicit expression of eq 12 can be written with the substitution of eqs 7–10. The flowchart of the proposed hybrid contour plot method is shown in Figure 8. The contour plots are drawn by generating a grid of f_{mob} and f_{mdry} values (for example, 100×100) to cover the range of interest. In the contour plot 1, S_w^t is solved using the golden section search method (the command “fminbnd” in MATLAB^{58,59}) for each (f_{mob} , f_{mdry}) pair, then f_g^t is calculated based on the value of S_w^t as well as f_{mob} and f_{mdry} for each triplet (f_{mob} , f_{mdry} , S_w^t). In the contour plot 2, S_w is solved with a zero-finding function (the command “fzero” in MATLAB^{58,59})

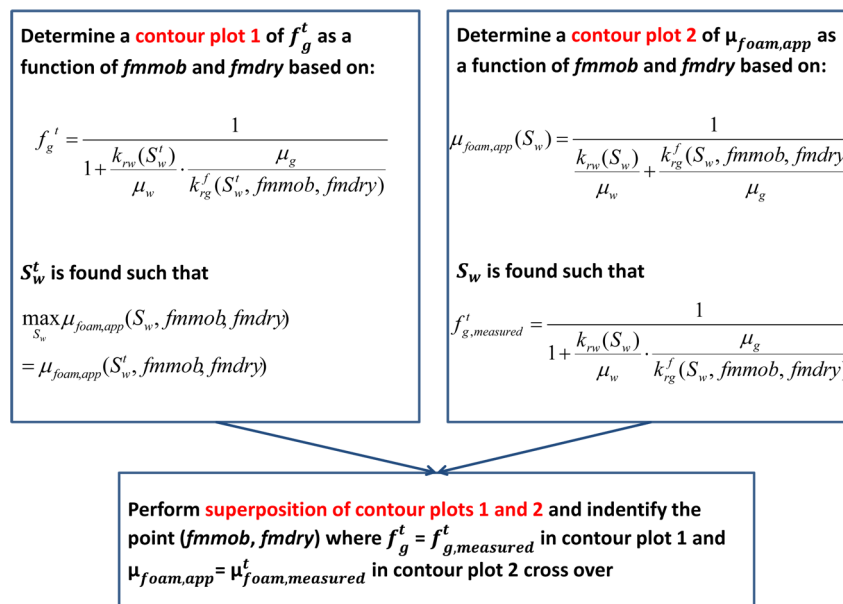


Figure 8. Flowchart for matching transition foam flow in porous media at steady state using the proposed hybrid contour plot method.

using the experimentally measured transition foam quality ($f_{g,\text{measured}}^t$) for each (fmmob, fmdry) pair, then $\mu_{\text{foam,app}}^t$ is calculated based on the value of S_w as well as fmmob and fmdry. As indicated in Figure 8, superposition of these two contour plots is performed to identify the point where $f_g^t = f_{g,\text{measured}}^t$ in the contour plot 1 and $\mu_{\text{foam,app}}^t = \mu_{\text{foam,measured}}^t$ in the contour plot 2 cross over. If a sufficiently fine grid is generated initially, one can enlarge the plot in MATLAB to obtain the parameter values with a desired level of accuracy without the need to repeat the whole process at a further-refined scale.

Fit for System A. We show the matching process of system A in Figure 2 as an example to explain the procedure in Figure 8 in detail. In this case, $f_g^t = 0.9$ and $\mu_{\text{foam,app}}^t = 527$ cp are obtained from the experimental data in Figure 2. According to the procedure in Figure 8, contour plots of f_g^t and $\mu_{\text{foam,app}}^t$ (at $f_g = f_{g,\text{measured}}^t$) with respect to fmmob and fmdry using MATLAB are drawn in color in parts a and b in Figure 9, respectively.

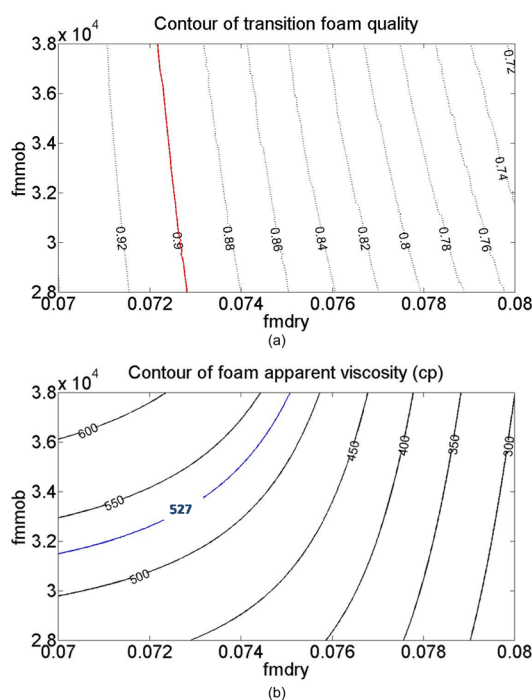


Figure 9. (a) Contour plot of transition foam quality as a function of fmmob and fmdry. The experimental transition foam quality is shown as the red curve. (b) Contour plot of foam apparent viscosity as a function of fmmob and fmdry. Injected gas fraction is set to be 0.9. The experimental transition foam apparent viscosity is shown as the blue curve. The rest of the parameters are used as shown in Table 1 (system A) with a preset epdry of 500.

Superposition of Figure 9a,b leads to a hybrid contour plot shown in Figure 10. In Figure 10, the red curve represents the contour line of $f_g^t = 0.9$ in Figure 9a, and the blue curve represents the contour line of $\mu_{\text{foam,app}}^t = 527$ cp in Figure 9b. The point (purple dot) where the red curve and the blue curve intersect indicates the parameters we search for matching the experimental data ($f_g^t = 0.9$ and $\mu_{\text{foam,app}}^t = 527$ cp). In this case, we obtain $\text{fmmob} = 3.30 \times 10^4$ and $\text{fmdry} = 0.073$ from Figure 10 after enlarging the plot in MATLAB.

Using $\text{fmmob} = 3.30 \times 10^4$ and $\text{fmdry} = 0.073$, the parameters in Table 1 (system A) and eqs 7 and 11, we compare the modeling profile of foam apparent viscosity with the experimental data in Figure 11. The simulation results

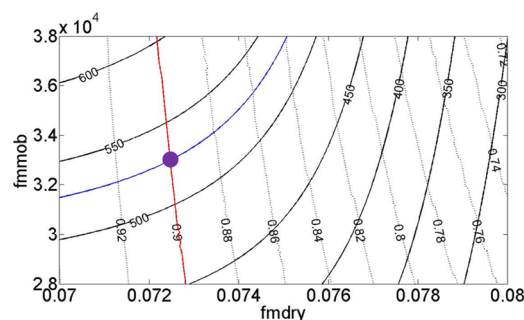


Figure 10. Superposition of contour plots in Figure 9a,b to find the position (the purple dot, $\text{fmmob} = 3.30 \times 10^4$ and $\text{fmdry} = 0.073$) where $f_g^t = 0.9$ (the red curve) and $\mu_{\text{foam,app}}^t = 527$ cp (the blue curve) cross over.

match the experimental data at the transition foam quality, indicating that our calculation is accurate and the proposed procedure in Figure 8 is valid. The modeling result matches the trend of the experimental data with some underestimation of the data points at low gas fractions. This underestimation could possibly be due to the trapped gas effect which we do not include here.

There is more than one way to solve eqs 12–14. We elaborated a direct numerical method and compared it with the findings using the hybrid contour plot method in part 2⁵⁴ of this series of papers.

Fit for System B. Using the same approach, we model the experimental data at a total superficial velocity of 20 ft/day (Figure 4) in system B with the F_2 function in the STARS foam model. The rest of the parameters are listed in Table 1 (system B). According to the experimental transition foam data shown in Figure 4 ($f_g^t = 0.5$ and $\mu_{\text{foam,app}}^t = 421$ cp), one can obtain the parameters $\text{fmmob} = 4.72 \times 10^4$ and $\text{fmdry} = 0.101$ as shown in Figure 12. Both high-quality and low-quality foam regimes are well modeled using this approach with the STARS foam model.

3.2.3. Comparison in Water Saturation. We compare the water saturation profile for system B in Figure 13 using the parameters in Table 1 and Figure 12. The modeling results are relatively close to the measured water saturation. The experimental data in Figure 13 is not strictly monotonically decreasing, possibly due to measurement uncertainty in low water saturation and the entrance and end effect in the system.^{10,60} The measurement uncertainty could possibly be that the water saturation has some fluctuations when the pressure drop appears stable at the steady state and that the water saturation in flow lines including dead volume may not be equal to the one in the sand pack. Note that we use $S_{wc} = 0.07$ in Table 1, which enables us to match the experimental data of measured water saturation. If one wants to get a closer match to a particular part in the water saturation profile, S_{wc} can be adjusted slightly. As initially S_{wc} is unknown, a good practice may be to use a value of S_{wc} for a similar system in the literature (0.04, for example, ref 34). Then a search for foam modeling parameters can be conducted. After that, one can compare the water saturation between modeling results and experimental data. If the water saturation is overestimated or underestimated, some fine-tunings of S_{wc} are needed to obtain a good match to experimental data. In this case, a slight increase in S_{wc} from 0.04 to 0.07 results in an increase in estimated fmdry, but no significant change is found in the epdry value (around 500) for both transient and steady-state experiments.

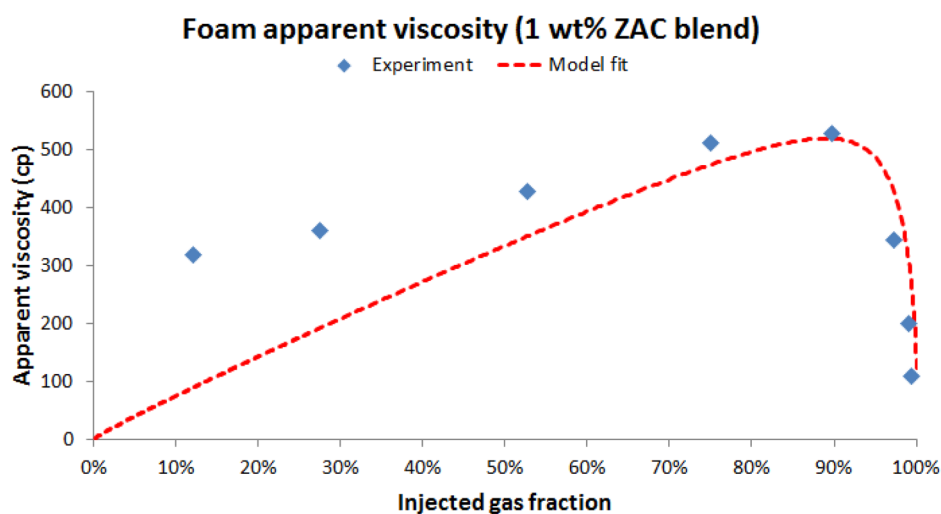


Figure 11. Comparison of foam apparent viscosities between the model fit and experiment in system A. $f_{mmob} = 3.30 \times 10^4$ and $f_{mdry} = 0.073$ are used in the foam model. The rest of the parameters are used as shown in Table 1 (system A) with a preset $epdry$ of 500.

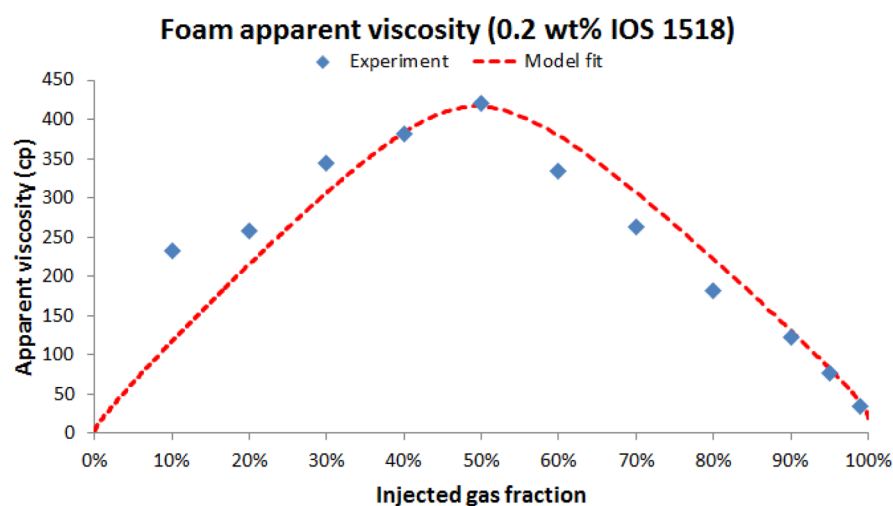


Figure 12. Comparison of foam apparent viscosities between the model fit and experiment in system B. $f_{mmob} = 4.72 \times 10^4$ and $f_{mdry} = 0.101$ are used in the foam model. The rest of the parameters are used as shown in Table 1 (system B) with a preset $epdry$ of 500.

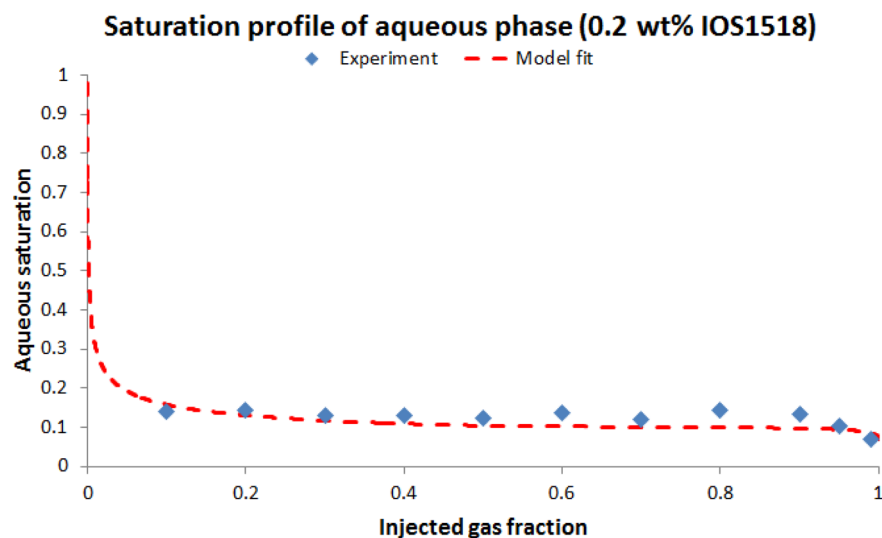


Figure 13. Comparison in water saturation between the experimental data and modeling results in system B using the parameters in Table 1 (system B) and Figure 12.

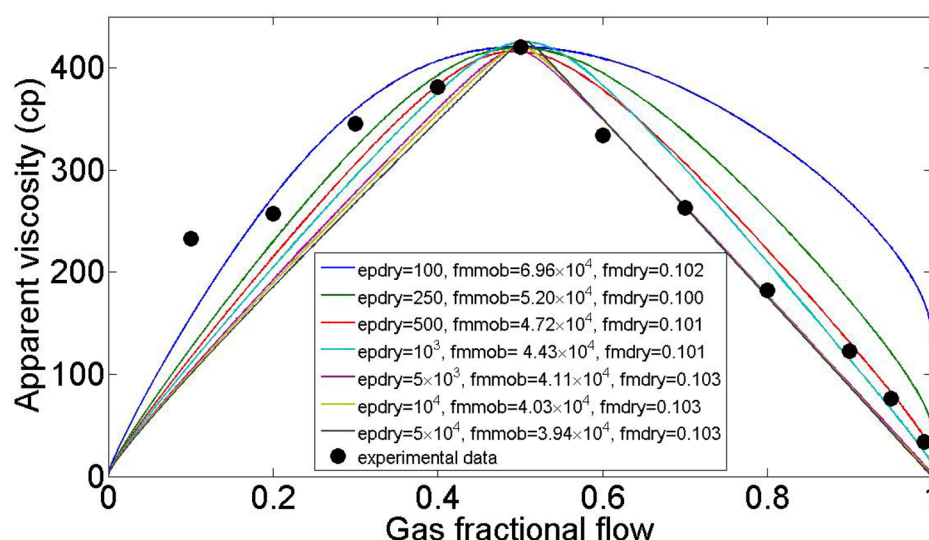


Figure 14. Model fit to experimental data in system B with different preset *epdry*. *fmmob* and *fmdry* are calculated using the method shown in Figure 8 for each value of *epdry*. Except for *epdry*, *fmmob*, and *fmdry*, the rest of the parameters are used as shown in Table 1 (system B).

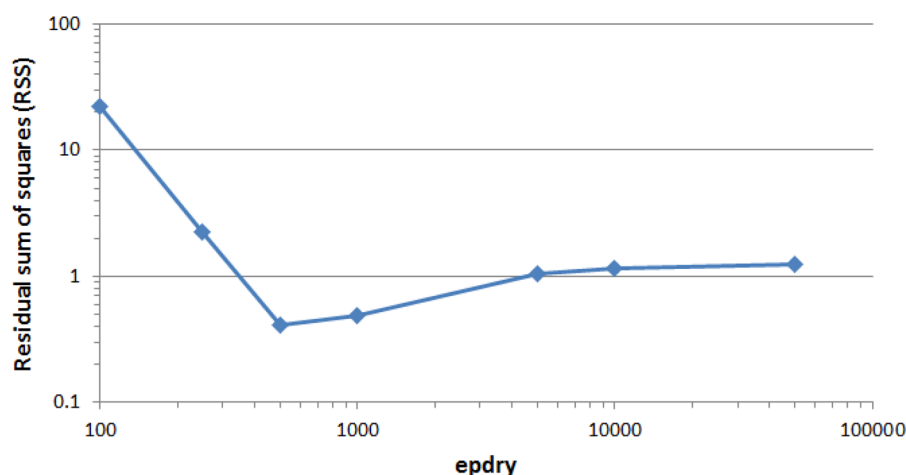


Figure 15. Residual sum of squares as a function of *epdry* for modeling the steady-state experiments in system B. *fmmob* and *fmdry* are calculated using the method shown in Figure 8 for each preset value of *epdry*. Except for *epdry*, the rest of the parameters are used as shown in Table 1 (system B).

3.2.4. Estimation of *epdry*. The parameter *epdry* regulates the slope of the F_2 curve when S_w is near *fmdry*. It was found that reducing *epdry* causes a deviation of ∇p contours from exactly vertical lines in the high-quality regime and exactly horizontal lines in the low-quality regime.⁴¹ To identify which value of *epdry* provides the best fit to all of the steady-state experiments, we define the residual sum of squares deviation (RSS) by comparing the relative difference between modeling results and experimental data:

$$RSS = \sum_{i=1}^n \left(\frac{\mu_{i, \text{calculated}} - \mu_{i, \text{measured}}}{\mu_{i, \text{measured}}} \right)^2 \quad (15)$$

The calculated foam apparent viscosities are based on the hybrid contour plot method shown in Figures 8–10 in which the transition foam data is fit with a precision of three significant digits. We use the 11 steady-state experimental data points in system B as an example to show how RSS varies with *epdry*. The model fit with different preset *epdry* is shown in Figure 14 using the method described in Figure 8. As indicated

in Figure 15, there exists a minimal RSS in a range between 100 and 50 000 for *epdry*. For this set of experimental data, the minimum of RSS is obtained with an *epdry* value of around 500. Nevertheless, for other values of *epdry* which are larger than 500, the fit to steady-state data also seems reasonable (Figure 14) with relatively small RSS values shown in Figure 15. This is implying that a wide range of *epdry* can be used to model this set of steady-state data.

An additional transient (continuous gas injection) experiment may further narrow down the range of *epdry* which we should consider. The experimental procedure is described in section 2.1.1, which is continuous gas injection to a surfactant-solution-saturated sand pack at a constant flow rate. We program an in-house foam simulator using the IMPES (implicit in pressure and explicit in saturation) finite difference algorithm to conduct transient simulation and to match experimental data. A total of 200 grid blocks ($NX = 200$) are used for the transient simulation, and the rest of the parameters are consistent with those in Table 1 except for *epdry*. The capillary pressure function is set to zero, and the algorithm assumes 1-D, incompressible, isothermal flow.

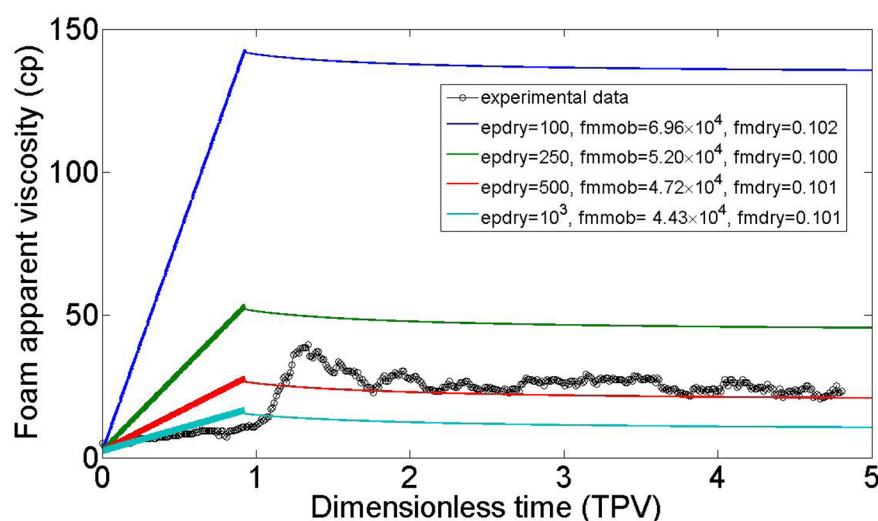


Figure 16. Comparison between transient experimental data and simulation results in system B. f_{mob} and f_{dry} are calculated using the method shown in Figure 8 for each value of ep_{dry} . Except for ep_{dry} , the rest of the parameters are used as shown in Table 1 (system B).

As shown in Figure 16, foam apparent viscosity gradually goes up when gas is injected into the porous medium. The maximum apparent viscosity (39.6 cP with a pressure drop of 0.77 psi) is achieved at 1.34 TPV in the experiment. After 1.34 TPV, a typical dry-out effect is observed and foam gradually loses the strength as an effect of the limiting capillary pressure.²⁴ Note that we define the total pore volume (TPV) of injected gas using the gas volume with an ambient absolute pressure (14.7 psia). If we define 1 TPV gas using the average pressure at the peak apparent viscosity, then the time for peak apparent viscosity should be 1.31 TPV which does not make much difference compared with 1.34 TPV. So the compressibility of gas cannot explain the late peak in foam apparent viscosity. Meanwhile, the time of gas breakthrough observed in this experiment is 0.70 TPV, which is much earlier than the time when the maximum foam strength is observed. This observation indicates that after gas breakthrough foam is still being created and refined in porous media. It is possible that weak foam (coarse bubbles) travels ahead of strong foam (fine bubbles) in this experiment.

The foam modeling parameters used in Figure 16 is a subset of those in Figure 14. Among different sets of model fit using the estimation method proposed in Figure 8, it appears that the parameter set with an ep_{dry} slightly smaller than 500 is close to experimental observation especially after gas breakthrough. Figure 16 also reveals an issue with the STARS foam model: foam generation is faster in the simulation than the experiment. The population balance model^{18,29–33} may describe in situ foam generation and coalescence on the laboratory scale more accurately than the local steady-state STARS foam model.

Nevertheless, if one accepts the local-steady-state model fit to these data, then the suitable value of ep_{dry} is around 500 for matching both steady-state and transient experiments in system B. However, how the value of ep_{dry} depends on other properties in the system, such as surfactant type and concentration, still needs further investigation.

4. CONCLUSIONS

In summary, we propose an approach to obtain the parameters in the STARS foam model for foam simulation. Two systems with different experimental conditions are successfully modeled

using the proposed technique. This approach estimates the parameters f_{mob} and f_{dry} by matching the transition foam apparent viscosity ($\mu_{foam,app}^t$) at the transition foam quality (f_g^t). The parameter ep_{dry} is estimated by examining the fit to the rest of the steady-state data and the transient experiment with continuous gas injection. To achieve a better accuracy of the model fit at the transition foam quality, the difference between the foam model parameter f_{dry} and the transition water saturation S_w^t is identified and a method to precisely calculate S_w^t is developed. The difference between f_{dry} and S_w^t becomes large when ep_{dry} becomes small, which corresponds to a more gradual transition between the high-quality foam regime and the low-quality foam regime. We show how a different preset ep_{dry} leads to different f_{mob} and f_{dry} for fitting a set of steady-state experimental data using the proposed approach. For the 0.2 wt % IOS1518 system, we demonstrate that an additional transient experiment with continuous gas injection is necessary to narrow down the range for ep_{dry} . The combination of steady-state and transient experiments may lead to an estimation of a unique set of parameters in the dry-out foam model.

AUTHOR INFORMATION

Corresponding Author

*Fax: +1 7133485478. E-mail: gjh@rice.edu.

Notes

The authors declare no competing financial interest.

ACKNOWLEDGMENTS

Part of this work was originally presented at the 2012 AIChE Spring Meeting and 8th Global Congress on Process Safety held in Houston, TX, April 1–5, 2012. We acknowledge financial support from the Abu Dhabi National Oil Company (ADNOC), the Abu Dhabi Oil R&D Sub-Committee, Abu Dhabi Company for Onshore Oil Operations (ADCO), Zakum Development Company (ZADCO), Abu Dhabi Marine Operating Company (ADMA-OPCO), and the Petroleum Institute (PI), U.A.E, and partial support from the U.S. Department of Energy (under Award No. DE-FE0005902) and Petróleos Mexicanos (PEMEX). We thank Professors Rouhi Farajzadeh and William R. Rossen from Delft University of

Technology for valuable discussions. We also thank Aarthi Muthuswamy at Rice University for assistance in the foam flooding experiments.

NOMENCLATURE

epdry = parameter regulating the slope of F_2 curve near fmdry
 f = fractional flow
 f_g^t = transition foam quality where the maximum foam apparent viscosity is achieved
 FM = dimensionless interpolation factor in STARS foam model
 $fmdry$ = critical water saturation in STARS foam model
 $fmmob$ = reference mobility reduction factor in STARS foam model
 F_2 = a function describing the contribution of aqueous phase saturation in the STARS foam model
 k = permeability, darcy
 k_r = relative permeability
 k_{rw}^0 = end-point relative permeability of aqueous phase
 k_{rg}^0 = end-point relative permeability of gaseous phase
 p = pressure, psi
 P_c = capillary pressure, psi
 P_c^* = limiting capillary pressure, psi
 u = superficial (Darcy) velocity, ft/day
 S = saturation
 S_w^t = transition water saturation where the maximum foam apparent viscosity is achieved
 μ = viscosity, cp
 $\mu_{foam,app}$ = foam apparent viscosity, cp
 $\mu_{foam,app}^t$ = maximum foam apparent viscosity obtained at the transition foam quality, cp

Superscripts

nf = without foam
 f = with foam
 n_g = exponent in k_{rg} curve
 n_w = exponent in k_{rw} curve
 t = transition between high-quality and low-quality foam

Subscripts

g = gaseous phase
 gr = residual gas
 w = aqueous phase
 wc = connate water

REFERENCES

- (1) Hirasaki, G. J. The steam-foam process. *J. Petrol. Technol.* **1989**, 41 (5), 449–456.
- (2) Kovscek, A. R.; Radke, C. J. Fundamentals of Foam Transport in Porous-Media In *Foams: Fundamentals and Applications in the Petroleum Industry*; Advances in Chemistry, Vol. 242; American Chemical Society: Washington, DC, 1994; Chapter 3, pp 115–163.
- (3) Gauglitz, P. A.; Friedmann, F.; Kam, S. I.; Rossen, W. R. Foam generation in homogeneous porous media. *Chem. Eng. Sci.* **2002**, 57 (19), 4037–4052.
- (4) Li, R. F.; Yan, W.; Liu, S. H.; Hirasaki, G. J.; Miller, C. A. Foam mobility control for surfactant enhanced oil recovery. *SPE J.* **2010**, 15 (4), 934–948.
- (5) Heller, J. P. CO₂ Foams in Enhanced Oil-Recovery. In *Foams: Fundamentals and Applications in the Petroleum Industry*; Advances in Chemistry, Vol. 242; American Chemical Society: Washington, DC, 1994; Chapter 5, pp 201–234.
- (6) Farajzadeh, R.; Andrianov, A.; Krastev, R.; Hirasaki, G. J.; Rossen, W. R. Foam-oil interaction in porous media: Implications for foam assisted enhanced oil recovery. *Adv. Colloid Interface Sci.* **2012**, 183, 1–13.
- (7) Wang, S. L.; Mulligan, C. N. Rhamnolipid foam enhanced remediation of cadmium and nickel contaminated soil. *Water Air Soil Pollut.* **2004**, 157 (1–4), 315–330.
- (8) Hirasaki, G. J.; Miller, C. A.; Szafranski, R.; Lawson, J. B.; Akiya, N. Surfactant/foam process for aquifer remediation. In *International Symposium on Oilfield Chemistry (SPE 37257)*, Houston, TX, 1997.
- (9) Casteel, J. F.; Djabbarah, N. F. Sweep Improvement in CO₂ Flooding by Use of Foaming Agents. *SPE Reservoir Eng.* **1988**, 3 (4), 1186–1192.
- (10) Farajzadeh, R.; Andrianov, A.; Bruining, H.; Zitha, P. L. J. Comparative Study of CO₂ and N₂ Foams in Porous Media at Low and High Pressure-Temperatures. *Ind. Eng. Chem. Res.* **2009**, 48 (9), 4542–4552.
- (11) Andrianov, A.; Farajzadeh, R.; Nick, M. M.; Talanana, M.; Zitha, P. L. J. Immiscible Foam for Enhancing Oil Recovery: Bulk and Porous Media Experiments. *Ind. Eng. Chem. Res.* **2012**, 51 (5), 2214–2226.
- (12) Khalil, F.; Asghari, K. Application of CO₂-foam as a means of reducing carbon dioxide mobility. *J. Can. Petrol. Technol.* **2006**, 45 (5), 37–42.
- (13) Enick, R. M.; Olsen, D. K.; Ammer, J.; Schuller, W. Mobility and Conformance Control for Carbon Dioxide Enhanced Oil Recovery (CO₂-EOR) via Thickeners, Foams, and Gels - A Detailed Literature Review of 40 Years of Research and Pilot Tests. In *SPE Improved Oil Recovery Symposium (SPE 154122)*, Tulsa, Oklahoma, 2012.
- (14) Al-Basry, A. H.; Al-Hajeri, S. K.; N., H. Saadawi, H.; Aryani, F. M. A.; Obeidi, A. A.; Negahban, S.; Bin-dhaaer, G. S. Lessons learned from the first miscible CO₂-EOR pilot project in heterogeneous carbonate oil reservoir in Abu Dhabi, UAE. In *SPE Middle East Oil and Gas Show and Conference (SPE 142665)*, Manama, Bahrain, 2011.
- (15) Gray, J. S.; Reynolds, A. D.; Pedron, B.; Khakoo, M.; Jenaibi, F. A. Understanding reservoir & system uncertainties to enable CO₂ EOR. In *Abu Dhabi International Petroleum Exhibition and Conference (SPE 138552)*, Abu Dhabi, UAE, 2010.
- (16) Farajzadeh, R.; Wassing, B. M.; Boerrigter, P. M. Foam assisted gas-oil gravity drainage in naturally-fractured reservoirs. *J. Pet. Sci. Eng.* **2012**, 94–95, 112–122.
- (17) Bernard, G. G.; Holm, L. W. Effect of foam on permeability of porous media to gas. *Soc. Petrol. Eng. J.* **1964**, 4 (3), 267–274.
- (18) Falls, A. H.; Hirasaki, G. J.; Patzek, T. W.; Gauglitz, D. A.; Miller, D. D.; Ratulowski, T. Development of a mechanistic foam simulator: the population balance and generation by snap-Off. *SPE Reservoir Eng.* **1988**, 3 (3), 884–892.
- (19) Kovscek, A. R.; Bertin, H. J. Foam mobility in heterogeneous porous media-(I: Scaling concepts). *Transport Porous Media* **2003**, 52 (1), 17–35.
- (20) Hirasaki, G. J.; Lawson, J. B. Mechanisms of foam flow in porous media - apparent viscosity in smooth capillaries. *Soc. Petrol. Eng. J.* **1985**, 25 (2), 176–190.
- (21) Li, R. F.; Hirasaki, G.; Miller, C. A.; Masalmeh, S. K. Wettability Alteration and Foam Mobility Control in a Layered, 2D Heterogeneous Sandpack. *SPE J.* **2012**, 17 (4), 1207–1220.
- (22) Rossen, W. R. Theory of mobilization pressure-gradient of flowing foams in porous media. I. Incompressible foam. *J. Colloid Interface Sci.* **1990**, 136 (1), 1–16.
- (23) Tanzil, D.; Hirasaki, G. J.; Miller, C. A. Conditions for foam generation in homogeneous porous media. In *SPE/DOE Improved Oil Recovery Symposium (SPE 75176)*, Tulsa, OK, 2002.
- (24) Khatib, Z. I.; Hirasaki, G. J.; Falls, A. H. Effects of capillary pressure on coalescence and phase mobilities in foams flowing through porous media. *SPE Reservoir Eng.* **1988**, 3 (3), 919–926.
- (25) Osterloh, W. T.; Jante, M. J., Jr. Effects of gas and liquid velocity on steady-state foam flow at high temperature. In *SPE/DOE Enhanced Oil Recovery Symposium (SPE 24179)*, Tulsa, OK, 1992.
- (26) Rossen, W. R.; Wang, M. W. Modeling foams for acid diversion. *SPE J.* **1999**, 06, 92–100.

- (27) Alvarez, J. M.; Rivas, H. J.; Rossen, W. R. Unified model for steady-state foam behavior at high and low foam qualities. *SPE J.* **2001**, *6* (3), 325–333.
- (28) Ma, K.; Lontas, R.; Conn, C. A.; Hirasaki, G. J.; Biswal, S. L. Visualization of improved sweep with foam in heterogeneous porous media using microfluidics. *Soft Matter* **2012**, *8* (41), 10669–10675.
- (29) Patzek, T. W. Description of foam flow in porous media by the population balance method. *ACS Symp. Ser.* **1988**, *373*, 326–341.
- (30) Kovscek, A. R.; Patzek, T. W.; Radke, C. J. A mechanistic population balance model for transient and steady-state foam flow in Boise sandstone. *Chem. Eng. Sci.* **1995**, *50* (23), 3783–3799.
- (31) Myers, T. J.; Radke, C. J. Transient foam displacement in the presence of residual oil: Experiment and simulation using a population-balance model. *Ind. Eng. Chem. Res.* **2000**, *39* (8), 2725–2741.
- (32) Kam, S. I.; Rossen, W. R. A model for foam generation in homogeneous media. *SPE J.* **2003**, *8* (4), 417–425.
- (33) Bertin, H. J.; Quintard, M. Y.; Castanier, L. M. Development of a bubble-population correlation for foam-flow modeling in porous media. *SPE J.* **1998**, *3* (4), 356–362.
- (34) Kam, S. I.; Nguyen, Q. P.; Li, Q.; Rossen, W. R. Dynamic simulations with an improved model for foam generation. *SPE J.* **2007**, *12* (1), 35–48.
- (35) Friedmann, F.; Chen, W. H.; Gauglitz, P. A. Experimental and simulation study of high-temperature foam displacement in porous media. *SPE Reservoir Eng.* **1991**, *6* (1), 37–45.
- (36) Chen, Q.; Gerritsen, M. G.; Kovscek, A. R. Modeling foam displacement with the local-equilibrium approximation: theory and experimental verification. *SPE J.* **2010**, *15* (1), 171–183.
- (37) Dholkawala, Z. F.; Sarma, H. K.; Kam, S. I. Application of fractional flow theory to foams in porous media. *J. Pet. Sci. Eng.* **2007**, *57* (1–2), 152–165.
- (38) Afsharpoor, A.; Lee, G. S.; Kam, S. I. Mechanistic simulation of continuous gas injection period during surfactant-alternating-gas (SAG) processes using foam catastrophe theory. *Chem. Eng. Sci.* **2010**, *65* (11), 3615–3631.
- (39) Mohammadi, S. S.; Coombe, D. A.; Stevenson, V. M. Test of steam-foam process for mobility control in South-Casper Creek reservoir. *J. Can. Pet. Technol.* **1993**, *32* (10), 49–54.
- (40) Zhou, Z.; Rossen, W. R. Applying fractional-flow theory to foam processes at the “limiting capillary pressure”. *SPE Adv. Technol. Ser.* **1995**, *3* (1), 154–162.
- (41) Cheng, L.; Reme, A. B.; Shan, D.; Coombe, D. A.; Rossen, W. R. Simulating foam processes at high and low foam qualities. In *SPE/DOE Improved Oil Recovery Symposium* (SPE 59287), Tulsa, OK, 2000.
- (42) Vassenden, F.; Holt, T. Experimental foundation for relative permeability modeling of foam. *SPE Reservoir Eval. Eng.* **2000**, *3* (2), 179–185.
- (43) Computer Modeling Group Ltd. *STARS User's Guide*; Computer Modeling Group Ltd.: Calgary, Alberta, Canada, 2007.
- (44) Renkema, W. J.; Rossen, W. R. Success of foam SAG processes in heterogeneous reservoirs. In *SPE Annual Technical Conference and Exhibition* (SPE 110408), Anaheim, CA, 2007.
- (45) Boeije, C. S.; Rossen, W. R. Fitting foam simulation model parameters to data. In *17th European Symposium on Improved Oil Recovery*, St. Petersburg, Russia, 2013.
- (46) Masalmeh, S. K.; Wei, L.; Blom, C. P. A. Mobility control for gas injection in heterogeneous carbonate reservoirs: comparison of foams versus polymers. In *SPE Middle East Oil and Gas Show and Conference* (SPE 142542), Manama, Bahrain, 2011.
- (47) Zanganeh, M. N.; Kam, S. I.; LaForce, T. C.; Rossen, W. R. The method of characteristics applied to oil displacement by foam. *SPE J.* **2011**, *16* (1), 8–23.
- (48) Ashoori, E.; van der Heijden, T. L. M.; Rossen, W. R. Fractional-flow theory of foam displacements with oil. *SPE J.* **2010**, *15* (2), 260–273.
- (49) Liu, M.; Andrianov, A.; Rossen, W. R. Sweep efficiency in CO₂ foam simulations with oil. In *SPE EUROPEC/EAGE Annual Conference and Exhibition* (SPE 142999), Vienna, Austria, 2011.
- (50) Vassenden, F.; Holt, T.; Ghaderi, A.; Solheim, A. Foam propagation on semi-reservoir scale. *SPE Reservoir Eval. Eng.* **1999**, *2* (5), 436–441.
- (51) Chalbaud, C. A.; Moreno, R. A.; Alvarez, J. M. Simulating foam process for a Venezuelan pilot test. In *SPE Annual Technical Conference and Exhibition* (SPE 77699), San Antonio, TX, 2002.
- (52) Blaker, T.; Aarra, M. G.; Skauge, A.; Rasmussen, L.; Celius, H. K.; Martinsen, H. A.; Vassenden, F. Foam for Gas Mobility Control in the Snorre Field: The FAWAG Project. *SPE Reservoir Eval. Eng.* **2002**, *5* (4), 317–323.
- (53) Skauge, A.; Aarra, M. G.; Surguchev, L.; Martinsen, H. A.; Rasmussen, L. Foam-assisted WAG: experience from the Snorre field. In *SPE/DOE Improved Oil Recovery Symposium* (SPE 75157), Tulsa, OK, 2002.
- (54) Ma, K.; Farajzadeh, R.; Lopez-Salinas, J. L.; Miller, C. A.; Biswal, S. L.; Hirasaki, G. J. Estimation of parameters for the simulation of foam flow through porous media: Part 3; non-uniqueness, numerical artifact and sensitivity. In *SPE Enhanced Oil Recovery Conference* (SPE 165263), Kuala Lumpur, Malaysia, 2013.
- (55) Falls, A. H.; Musters, J. J.; Ratulowski, J. The Apparent Viscosity of Foams in Homogeneous Bead Packs. *SPE Reservoir Eng.* **1989**, *4* (2), 155–164.
- (56) Bruges, E. A.; Latto, B.; Ray, A. K. New correlations and tables of coefficient of viscosity of water and steam up to 1000 bar and 1000 degrees C. *Int. J. Heat Mass Transfer* **1966**, *9* (5), 465–480.
- (57) Lemmon, E. W.; Jacobsen, R. T. Viscosity and thermal conductivity equations for nitrogen, oxygen, argon, and air. *Int. J. Thermophys.* **2004**, *25* (1), 21–69.
- (58) The MathWorks, Inc. *MATLAB User's Guide*; The Math Works, Inc.: Natick, MA, 2012.
- (59) Brent, R. P. *Algorithms for Minimization without Derivatives*; Prentice-Hall: Englewood Cliffs, NJ, 1973.
- (60) Du, D. X.; Beni, A. N.; Farajzadeh, R.; Zitha, P. L. J. Effect of water solubility on carbon dioxide foam flow in porous media: An X-ray computed tomography study. *Ind. Eng. Chem. Res.* **2008**, *47* (16), 6298–6306.