Effect of Surfactant Partitioning between Gaseous Phase and Aqueous Phase on CO₂ Foam Transport for Enhanced Oil Recovery

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ABSTRACT: CO_2 flood is one of the most successful and promising enhanced oil recovery technologies. However the displacement is limited by viscous fingering, gravity segregation and reservoir heterogeneity. Foaming the CO_2 and brine with a tailored surfactant can simultaneously

address these three problems and improve the recovery efficiency. Commonly chosen surfactants as foaming agents are either anionic or cationic in class. These charged surfactants are insoluble in either CO_2 gas phase or supercritical phase and can only be injected with water. However, some novel nonionic or switchable surfactants are CO_2 soluble, thus making it possible to be injected with the CO_2 phase. Since surfactant could be present in both CO_2 and aqueous phases, it is important to understand how the surfactant partition coefficient influences foam transport in porous media. Thus, a 1-D foam simulator embedded with STARS foam model is developed. All test results, from different cases studied, have demonstrated that when surfactant partitions approximately equally between gaseous phase and aqueous phase, foam favors oil displacement in regard with apparent viscosity and foam propagation speed. The test results from the 1-D simulation are compared with the fractional flow theory analysis reported in literature.

1. Introduction:

 CO_2 flooding is widely used to displace crude oil in reservoirs after primary and secondary recovery. It is one of the most successful enhanced oil recovery (EOR) technologies and accounts for almost half of the oil produced by EOR in United States (Thomas 2008). However, the recovery efficiency is limited by viscous fingering and gravity override because of the relatively low viscosity and low density of CO_2 compared to the displaced phase; moreover, reservoir heterogeneity would further lower the CO_2 sweep efficiency and cause an early gas breakthrough (Lake 2010).

Foaming the CO₂ and brine with a tailored surfactant can simultaneously address viscous fingering, gravity override, reservoir heterogeneity, and thus enhance the recovery (Schramm 1994). Foam in porous media is defined as a dispersion of gas in a liquid such that the liquid phase (wetting phase) is continuous and at least some part of the gas phase (non-wetting phase) is made discontinuous by thin liquid films called (Falls et al. 1988). Foam usually has an apparent viscosity of several orders of magnitude greater than the viscosity of pure gas. It can lower the mobility ratio between the displacing phase and displaced phase, thus stabilizing the displacement. Furthermore, the rheology behavior of foam is such that mitigates the effect of reservoir heterogeneity (Conn et al. 2014; Liontas et al. 2013; Li et al. 2008) because it generates a stronger flow resistance in high permeable region, while creating a weaker flow resistance in low

Foam is a thermodynamically metastable system, which requires surfactants to preferentially adsorb onto the gas-liquid interface to lower the interfacial energy and stabilize lamella. Commonly used ionic and zwitterionic surfactants such as alpha olefin sulfonate (AOS), dodecyltrimethylammonium bromide (DTAB) and lauryl betaine (LB) are insoluble in gas phase and can only be injected with water. However some nonionic surfactants, mainly ethoxylated alcohols, are CO₂ soluble thus making it possible to inject surfactants with gas phase (Xing et al. 2012). Besides nonionic surfactants, some novel CO₂ soluble surfactants, ethoxylated amines, (Chen et al. 2015; Chen et al. 2014; Cui et al. 2016) can switch from nonionic to cationic by protonating the amine group according to the pH in solutions (Cui et al. 2014). Injected in CO₂, the surfactant will automatically dissolve into the aqueous phase and foam (Elhag et al. 2014).

Injecting surfactant in CO_2 shows some major advantages over injecting surfactant in water. Because of operational constraints and injectivity limitations, gas and liquid coinjection is not an option for foam processes at the reservoir scale. What is commonly applied is alternating injection of gas and water slugs that is here described either as (1) a Surfactant-Alternating-Gas (SAG) process when the surfactant is injected into the aqueous phase or as (2) a Water-Alternating-Gas-with-Surfactant-in-Gas (WAGS) process(Le et al. 2008) when the surfactant is injected in gas phase. If surfactant is injected in water, a large amount of surfactant could be wasted if the surfactant quickly falls with the water phase by gravity segregation before interacting with the gas slugs. It might be a more severe issue if the slug size is large and the reservoir is highly heterogeneous in vertical direction. On the contrary, when surfactant is injected in gaseous phase and flows with the CO_2 , it can generate foam when gas-containing surfactant comes in contact with the formation brine or injection water left behind from secondary recovery. Thus, it can enlarge the gas-water mixture (foam) zone before complete phase segregation happens. Another advantage of injecting surfactant with gas is to improve the injectivity of water. If surfactant is injected in water, when switching injection from gas to water, strong foam may be generated near the wellbore region making it difficult to keep fluid injection at high flow rates. However if surfactant with a proper partition coefficient is injected with CO₂, foam will be much weaker near the wellbore, thus enhancing water injectivity.

Since CO_2 soluble surfactants can partition between gas phase and aqueous phase, it is of great importance to understand the effect of partition coefficient K_{sgw} on foam transport in the reservoir. Partition coefficient is defined as the surfactant concentration ratio between gaseous phase and aqueous phase at equilibrium condition:

$$K_{sgw} = \frac{C_{sg}}{C_{sw}}$$
 Equation 1

Because of the amphiphilicity of the molecular structure, CO_2 soluble surfactants may be either more hydrophilic (small partition coefficient) or more CO_2 -philic (large partition coefficient). Partition coefficient reported in (Ren et al. 2011) also indicates that even for a specific surfactant, it may change with varied reservoir conditions. A reasonable value for partition coefficient K_{sgw} can be expected in the range of 0.01 and 5.00.

A series of interesting experimental observations were reported by Ren et (Ren et al. 2011) regarding the effect of surfactant partitioning between CO_2 and water. Core-scale CO_2 foam floods were conducted with 4 different types of surfactants with different partition coefficients by co-injecting CO_2 and surfactant solution (that is to say surfactant

was injected in water). It was concluded that there is an optimal partition coefficient for fastest foam propagation.

Another intuitive analysis, described by Ashoori et al(Ashoori et al. 2009), utilized fractional flow theory to conceptualize the first-contact-miscible gas flood with surfactant dissolved in CO₂. This theoretical work sheds light upon the effect of surfactant partitioning on foam propagation. Other variables such as surfactant foamability and adsorption were held constant when surfactant partition coefficient was varied. It was concluded that weaker surfactant partitioning from CO₂ to water (larger partition coefficient K_{sgw}) is advantageous to accelerate foam propagation velocity.

In this paper, a more generalized 1-D foam simulator is developed to investigate foam transport with respect to different surfactant partition coefficients. Different foam models have been proposed in literature to simulate foam transport in porous media (Ma et al. 2015). Most of the foam models have been developed based on the fact that gas relative permeability in presence of foam is greatly reduced (which is equivalent to viscosifying the gas) whereas the relative permeability for a given saturation of water remains unchanged (Rossen 2013).

Embedded in our 1-D reservoir simulator is STARS foam model which assumes lamella generation and coalescence rates are locally at equilibrium (Farajzadeh et al. 2013; Ma et al. 2014). Then the reduction of gas mobility is expressed as a function depending on variables such as surfactant concentration, water saturation, and capillary number etc.

The structure of the paper is as follows: firstly, we describe the STARS foam model and the details of the 1-D foam simulator; secondly, we show three different cases with varied K_{sgw} to systematically investigate the surfactant partitioning effect; finally, we end the paper with concluding remarks highlighting the important findings. It will be shown that the partition coefficient K_{sgw} can be optimized once the injection strategy (injection concentration of surfactant, slug size etc.) is determined.

2. Model Description

2.1. STARS Foam Model

The STARS is a local-equilibrium texture-implicit model in which the gas relative permeability with the presence of foam k_{rg}^{f} is obtained by multiplying the gas relative permeability without foam k_{rg}^{nf} at a given water saturation with a mobility reduction factor *FM*.

$$k_{rg}^{f} = k_{rg}^{nf} \times FM$$
 Equation 2

FM is inversely related to the product of different functions, which account for the foam dependences on different factors (surfactant concentration, water saturation, oil saturation and capillary number etc.).

$$FM = \frac{1}{1 + fmmob \times F1 \times F2 \times F3 \times F4 \times F5 \times F6 \times \dots}$$
 Equation 3

fmmob sets a reference to the maximum gas mobility reduction that can be achieved by foam. F1 to F6 are different functions all in the range of 0 to 1. When F1 to F6 are all equal to 1, foam correspondingly obtains its maximum strength. A full

description of STARS foam model can be found elsewhere (Cheng et al. 2000). This work only considers foam dependence on surfactant concentration (F1) and water saturation (F2). Then Equation 3 is reduced to

$$FM = \frac{1}{1 + fmmob \times F1 \times F2}$$
 Equation 4

F1 is surfactant concentration dependent function which is a function of surfactant concentration in aqueous phase C_{sw} as shown in Equation 5. There are two parameters in F1: *fmsurf* and *epsurf*. *fmsurf* describes the critical surfactant concentration above which foam strength no longer changes. *epsurf* is the power-law exponent. Empirically *fmsurf* is significantly higher than the critical micelle concentration (CMC). However it is not well understood how *fmsurf* is correlated with CMC. We find it by experimentally determining the surfactant concentration that begins to foam.

$$F1 = \begin{cases} \left(\frac{C_{sw}}{fmsurf}\right)^{epsurf} & for C_{sw} < fmsurf \\ 1 & for C_{sw} \ge fmsurf \end{cases}$$
 Equation 5

It would not be difficult to fit *fmsurf* and *epsurf* to experiments. For the sake of simplification, we assume linearity between F1 and C_{sw} by fixing *epsurf* to 1. We might as well set *fmsurf* to be 2 g/L (equivalent to 0.2 wt% in water) since what matters is not the absolute value of *fmsurf* but the ratio between surfactant concentration C_{sw} and *fmsurf*. The relationship between F1 and C_{sw} is shown in Figure 1.



Figure 1: The relationship between F1 and C_{sw} (*fmsurf=*2 g/L, *epsurf=*1)

F2 is the water saturation dependent function which is the inverse of a tangent function of water saturation S_w . It describes the dry-out effect when water saturation is low as shown in Equation 6.

$$F2 = 0.5 + \frac{\arctan[epdry(S_w - fmdry)]}{\pi}$$
 Equation 6

There are two parameters in F2 as well: *fmdry* and *epdry*. *fmdry* describes the water saturation around which foam starts drying out. *epsurf* regulates how abruptly foam will dry out when water saturation decreases. Large *epdry* indicates that foam will dry out sharply whereas small *epdry* indicates that foam will dry out gradually as shown in Figure 2. Different algorithms have been proposed in literature (Abbaszadeh et al. 2014; Boeije and Rossen 2013; Farajzadeh et al. 2013) to estimate *fmdry* and *epdry* based on lab-scale experiments. In this work we will preset *fmdry* to be 0.25 and *epdry* 500.



Figure 2: The relationship between F2 and S_w (fmdry=0.25, epdry=50, 500, 5000)

The Corey model is applied to correlate relative permeability and saturation as shown in Equation 7 and Equation 8. Then the relative-permeability reduction of gas phase by foam can be plotted out as shown in Figure 3. Parameters for STARS are listed in Table 1 and parameters for Corey model are listed in Table 2.

$$k_{rg}^{nf} = k_{rg}^{o} \left(\frac{1 - S_{gr} - S_{w}}{1 - S_{gr} - S_{wr}}\right)^{n_{g}}$$
 Equation 7

$$k_{rw} = k_{rw}^{o} \left(\frac{S_w - S_{wr}}{1 - S_{gr} - S_{wr}}\right)^{n_w}$$
Equation 8

Parameter		Value
fmmob		500
	fmsurf	2 g/L
<i>F</i> 1	epsurf	1
	fmdry	0.25
F2	epdry	500

Table 1: Parameters in STARS foam model

Table 2: Parameters in Corey relative permeability model

Parameter	Value	Comment
S _{wr}	0.05	residual water saturation
S _{gr}	0.05	residual gas saturation
k _{rw}	0.2	end-point relative permeability for water
k^o_{rg}	0.94	end-point relative permeability for gas
n _w	4.2	Corey exponent for water (wetting) phase
n_g	1.3	Corey exponent for gas (non-wetting) phase



Figure 3: Relative permeability of foam modeled using STARS foam simulator

2.2. 1-D Foam Simulator

A general form for conservation equation of mass (Lake 2010) is given by

$$\frac{\partial W_i}{\partial t} + \nabla \overrightarrow{N_i} - R_i = 0 \qquad (i = w, g, s)$$
 Equation 9

 W_i is the total concentration of *i* in units of mass of *i* per unit bulk volume. The index *i* can be *w* for water, *g* for gas or *s* for surfactant. For isothermal fluid flow in permeable media, W_i can be further expressed as shown in Equation 10 where ϕ is the porosity, ρ_j is the density of phase *j*, S_j is the saturation of phase *j*, ω_{ij} is the mass fraction of species *i* in phase *j*, N_p is the number of phases and subscript *s* in ω_{is} represents the mineral surface.

Equation 10

$$W_i = \phi \sum_{j=1}^{N_p} \rho_j S_j \omega_{ij} + (1 - \phi) \rho_s \omega_{is}$$

 $\overrightarrow{N_i}$ is the flux of species *i* which can be further divided to a convection term and a dispersion term as shown in Equation 11. $\overrightarrow{u_j}$ is the superficial velocity vector of phase *j* and K_{ij}^* is the dispersion tensor of species *i* in phase *j*.

$$\overrightarrow{N_{i}} = \sum_{j=1}^{N_{p}} \rho_{j} \omega_{ij} \overrightarrow{u_{j}} - \phi \rho_{j} S_{j} K_{ij}^{*} \cdot \nabla \omega_{ij}$$
Equation 11

In this work, there is no net production of species, thus the source term R_i in Equation 9 is equal to zero for all water, gas and surfactant.

Assumptions made include: foam is a two-phase (gaseous phase and aqueous phase) three-component (gas, water, and surfactant) incompressible fluid; gas and water are immiscible; the reservoir is a 1-D homogeneous porous medium; surfactant partitioning is at local equilibrium.

For gas and water:

$$W_g = \phi \rho_g S_g$$
 Equation 12

$$W_w = \phi \rho_w S_w$$
 Equation 13

$$\overrightarrow{N_g} = \rho_g \overrightarrow{u_g}$$
 Equation 14

$$\overrightarrow{N_w} = \rho_w \overrightarrow{u_w}$$
 Equation 15

Thus the conservation equations for gas and water become:

$$\phi \frac{\partial S_g}{\partial t} + \frac{\partial u_g}{\partial x} = 0$$
 Equation 16

$$\phi \frac{\partial S_w}{\partial t} + \frac{\partial u_w}{\partial x} = 0$$
 Equation 17

Surfactant can partition between gaseous phase and aqueous phase and be adsorbed on to the surface of the formation as well:

$$W_s = \phi \left(S_w C_{sw} + S_g C_{sg} \right) + (1 - \phi) C_{ss}$$
 Equation 18

$$\overrightarrow{N_s} = C_{sw} \overrightarrow{u_w} + C_{sg} \overrightarrow{u_g} - \phi [S_w K_{sw}^* \cdot \nabla C_{sw} + S_g K_{sg}^* \cdot \nabla C_{sg}]$$
Equation 19

The conservation equation for surfactant becomes:

$$\phi \frac{\partial \left(S_w C_{sw} + S_g C_{sg}\right)}{\partial t} + (1 - \phi) \frac{\partial C_{ss}}{\partial t} + \frac{\partial (C_{sw} u_w + C_{sg} u_g)}{\partial x}$$
Equation 20
$$= \phi \left[K_{sw}^* \frac{\partial}{\partial x} (S_w \cdot \frac{\partial C_{sw}}{\partial x}) + K_{sg}^* \frac{\partial}{\partial x} (S_g \cdot \frac{\partial C_{sg}}{\partial x})\right]$$

Additional equations include momentum balance for the two phases based on Darcy's law:

$$u_{g} = -\frac{kk_{rg}^{f}}{\mu_{g}}\frac{\partial p_{g}}{\partial x}$$
Equation 21
$$u_{w} = -\frac{kk_{rw}}{\mu_{w}}\frac{\partial p_{w}}{\partial x}$$
Equation 22

For simplicity, surfactant adsorption ($C_{ss}=0$) is neglected. Surfactant adsorption significantly hinders its propagation and its retardation is highly dependent of the type of fluid-rock interaction. For example, nonionic surfactants have a significantly lower adsorption onto mineral surface compared to ionic surfactants, which electrostatically interact with rock surfaces (Ren et al. 2013; Ren 2012). Also ethoxylated amines have shown to have low adsorption in most CO₂ saturated carbonate reservoirs (Chen et al. 2014; Cui et al. 2014; Elhag et al. 2014). Capillary pressure $(p_w = p_g)$ is also neglected in our simulation but it can be easily added with any capillary pressure model.

The 1-D model is solved by implicit-pressure-explicit-saturation (IMPES) procedure. Equations (16), (17), (20), (21), (22) are solved simultaneously in a dimensionless form. The detailed numerical method can be found elsewhere (Ma 2012). Important parameters for this 1-D CO_2 foam simulator are listed in Table 3.

Parameter	Value	Comment
NX	100	number of grid blocks
L	1.0	in feet, length of the 1-D formation
$\Delta t_D / \Delta x_D$	0.005	step length in dimensionless time
k	1.0	in Darcy, permeability of the formation
φ	0.25	porosity of the formation
ν	80	in ft/day, total interstitial velocity
Pe _w	500	Peclet number in aqueous phase $(Pe_w = \frac{Lv}{K_{sw}^*})$
Peg	500	Peclet number in gas phase $(Pe_g = \frac{Lv}{K_{sg}^*})$
μ_g	0.045	in cP, viscosity of CO ₂ (4000 psi, 120 °C)
μ_w	0.24	in cP, viscosity of water (4000 psi, 120 °C)

Table 3: Parameters for 1-D CO₂ foam simulator

With this 1-D CO₂ foam simulator, a series of numerical core-flood experiments were conducted to study the effect of surfactant partition coefficient on foam transport in porous media. In all cases, surfactant is injected with CO₂ as shown in Figure 4. Foam strength is quantified by apparent viscosity μ_{app} , which is defined as pressure gradient normalized with respect to permeability and total flux of both gas and liquid as shown in Equation 23.

$$\mu_{app} = -\frac{k\nabla p}{u_a + u_w}$$
 Equation 23



Figure 4: Scheme for numerical 1-D CO₂ foam core-flood experiment

3. Results and Discussions

Three different test cases will be simulated to systematically illustrate the effect of surfactant partition coefficient in this 1-D system. We assign three different characteristic

values to K_{sgw} to represent small, unity and large partition coefficient respectively as shown in Table 4.

Characteristic K _{sgw}	Value
Small	0.05
Unity	1.00
Large	4.00

Table 4: Characteristic values for surfactant partition coefficient K_{sgw}

3.1. Case I: CO₂ Displacing Water

In Case I, we continuously inject CO₂ to displace water. Initially the 1-D formation core is fully saturated with surfactant-free water, i.e., $S_{w_{-}}= 1$. Gas is then injected from the inflow end at a superficial velocity of 20 ft/day. The pressure at the outflow end is kept constant. Surfactant is injected with the gas phase with a concentration of 2.5 g/L, which is slightly higher than *fmsurf*.

Figure 5 illustrates the different situations when the surfactant partition coefficient K_{sgw} is small ($K_{sgw} = 0.05$), unity ($K_{sgw} = 1.00$) and large ($K_{sgw} = 4.00$). The snap shots are taken after injecting 0.50 total pore volume (TPV) of CO₂ into the core. The first plot is gas-saturation profile, which demonstrates the gas front in the porous medium. The dashed line (1 - fmdry) indicates the gas saturation around which foam starts drying out. The second plot is the profile of surfactant concentration in the aqueous phase, which indicates the surfactant transport and retardation in the aqueous phase. The dashed line indicates the critical concentration *fmsurf* above which foam strength is no longer dependent on the surfactant concentration. The third plot is the

apparent viscosity profile, which shows the position of the foam bank and foam strength inside the porous medium.



Figure 5: Case I: CO₂ displacing water

It can be seen from Figure 5 that for small partition coefficient ($K_{sgw} = 0.05$), surfactant and foam transport will be retarded. If surfactant is highly preferential to partition in water, even though injected in CO₂, the surfactant will be quickly stripped off from the gaseous phase and get highly concentrated near the wellbore region. Consequently the mobility control of CO₂ will be lost and an early gas breakthrough will be expected. Furthermore, the concentrated surfactant in the aqueous phase may cause precipitation issues if the nonionic surfactants have limited solubility in the aqueous phase.

For unity partition coefficient ($K_{sgw} = 1.00$), the surfactant transport is in accordance with gas front propagation. When surfactant is equally partitioned between the aqueous phase and the gaseous phase, CO₂ can hold the dissolved surfactant for a longer time and the gas breakthrough will be delayed. Surfactant concentration in water is kept around *fmsurf*. The foam front is strong enough so it displaces the water and increases the gas saturation effectively. Accordingly foam dries out quickly and foam bank is relatively shortened.

For a large partition coefficient ($K_{sgw} = 4.00$), surfactant transport is in accordance with the gas propagation and early gas breakthrough is avoided. However, the surfactant is highly spread out and the concentration in water drops below *fmsurf*. The foam front is not as strong as the unity partition coefficient. Thus foam displaces water in a less effective way. Foam bank is elongated.

3.2. Case II: Single Slug of CO₂ Followed by Water

In Case I when continuous gas is injected, foam dries out when water saturation drops below *fmdry*. In Case II, water is injected after a slug of CO_2 injection. In this case, the initial condition remains the same as that in Case I where the 1-D formation core is fully saturated with the surfactant-free water. The boundary condition now becomes that we first inject 0.2 TPV of CO_2 with 2.5 g/L surfactant and then switch to continuous water injection. Snap shots are also taken at 0.5 TPV of injection as shown in Figure 6.



Figure 6: Single slug of CO₂ followed by water

As can be seen from Figure 6, water injection after CO_2 /surfactant slug has different effects on foam and surfactant transport with respect to different partition coefficients. For small partition coefficient ($K_{sgw} = 0.05$), water injection can dilute the surfactant concentration near the injection wellbore and push the surfactant slug to move forward. However, the effect is limited and surfactant is still concentrated in a small region. The narrow distribution is a waste of surfactant and directly shortens foam bank. Foam is less strong than for unity partition coefficient. For unity partition coefficient ($K_{sgw} = 1.00$), water injection can mitigate the dry-out effect right after the foam front by quickly compensating the lost water. Thus foam bank is elongated and foam is the strongest. For large partition coefficient ($K_{sgw} = 4.00$), water injection will further dilute the surfactant concentration in aqueous phase and weaken the foam.

3.3. Case III: Water Alternating Gas (WAGS)

In the field, either continuous gas injection or a single slug of gas followed by water does not occur. Case III would represent a WAGS process where slugs of gas and water are injected alternatingly. Surfactant is still injected with CO_2 at the concentration of 2.5 g/L. Each cycle of WAGS consist of 0.20 TPV of CO_2 and 0.05 TPV of water. Figure 7 shows the snap shots taken at 0.5 TPV after 2 cycles of gas and water have been injected. Similar conclusion can be drawn that when surfactant is equally preferential to staying between CO_2 and water, we can generate the strongest foam strength and expect a relatively fast foam propagation velocity.



Figure 7: Water alternating gas (WAGS) simulated profiles

If *fmdry* and K_{sgw} are varied at the same time, we can plot out the contour of average apparent viscosity of foam after 1 TPV injection (which is equivalent to 4 cycles of CO₂/surfactant and water injection) with respect to *fmdry* and K_{sgw} for the same WAGS process.



Figure 8: Contour of apparent viscosity as a function of fmdry and K_{saw}

It can be seen from Figure 8 that in a wide range of *fmdry*, foam is of maximum strength (highest apparent viscosity) when surfactant partitions equally between gaseous phase and aqueous phase.

3.4. Simulation v.s. Fractional Flow Theory

As described in Section 1, Ashoori et al. (Ashoori et al. 2009) utilized fractionalflow theory to study the effect of surfactant partitioning when surfactant was continuously injected with CO_2 into a water saturated reservoir. Two fractional-flow curves were used to describe foam and CO_2 /water two-phase flow respectively. Foam front is where the CO_2 /water wave exceeds the foam wave and 'Buckley-Leverett' shock appears. Ahead of the foam front, gas will lose its mobility control and quickly break through the medium. It was concluded that greater surfactant partition from water to CO_2 (Large K_{sqw}) is favorable for foam propagation.

The 1-D simulation disclosed here can be reduced to fit the results obtained from fractional-flow theory by modifying the form of surfactant concentration dependent function *F*1. Ashoori et al. assumes that foam strength is only dependent on water saturation as shown in Equation 24. Namely, so long as surfactant exists locally, the foam fractional-flow curve governs the propagation of the saturation waves; otherwise CO_2 /water two-phase fractional-flow curve governs. Let's consider adjusting *F*1 to a step function, as shown in Equation 25. *C*_{threshold} is a threshold concentration (*C*_{threshold} is set to be 0.5 g/L) above which foam is of full strength at a given saturation otherwise foam does not exist. As shown in Figure 9, a consistent result can be obtained as by fractional-flow theory that larger surfactant partition coefficient can enhance foam propagation velocity and is favorable for displacement.

$$FM = \frac{1}{1 + fmmob \times F1 \times F2}$$
 Equation 24

$$F1 = \begin{cases} 0 & for C_{sw} < C_{threshold} \\ 1 & for C_{sw} \ge C_{threshold} \end{cases}$$
 Equation 25



Figure 9: CO_2 displacing water with modified form of *F*1 to reproduce the results given by fractional flow theory

Compared with Case I Figure 5, the surfactant concentration profiles are similar whereas the gas saturation profiles and foam apparent viscosity profiles are quite different. It is because the fractional flow theory and our reduced model oversimplify the foam dependence on surfactant concentration. It switches between full strength foam mode and gas-water two-phase flow model where gas mobility control is completely lost. In reality, foam strength monotonically increases with surfactant concentration until it reaches a plateau. However, if we only consider the position of the foam front in the gas-saturation profile in Figures 5-to-7, the fractional-flow analysis is also in accordance with previous simulation results in Case I, II and III. Regardless of foam strength (foam apparent viscosity), foam front travels faster when surfactant stays in and is transported with CO_2 (large K_{sgw}).

4. Conclusions

We have developed a more generalized 1-D foam simulator to study the effect of foam transport in porous media. The STARS model is utilized to describe the reduction of gas mobility by foam. The foam dependence on surfactant concentration and water saturation is accounted by two empirical functions introduced as F1 and F2. IMPES method is applied to solve the transport equations numerically. Three different cases are fully discussed to illustrate how surfactant distribution between phases can affect the transport of foam. It is found that large partition coefficient can enhance foam propagation whereas small partition coefficient can hold surfactant in the aqueous phase to strengthen the foam. When plotting contours of the apparent viscosity with respect to a wide range of fmdry, We clearly illustrated that a surfactant with unity partition coefficient is advantageous to foam transport in regard to foam strength and propagation speed. The effect of small, unity and large partition coefficient is listed in Table 5.

K_{sgw}	Small	Unity	Large
Gas Breakthrough	Early	Late	Late
Surfactant Concentration	Concentrated	Around <i>fmsurf</i>	Diluted
Surfactant Transport	Retarded	Fast	Fast
Foam Transport	Slow	Fast	Fast
Foam Bank	Short	Long	Long

Table 5: Effect of different partition coefficient on foam transport

This model can be modified to reproduce the results derived from fractional flow theory analysis by assuming that as long as surfactant is present, foam exists with a strength independent of surfactant concentration and then adjusting the form of surfactant concentration dependent function F1 accordingly.

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Nomenclature

$C_{s,q}$	Surfactant concentration in gas phase
C_{ss}	Surfactant concentration on the solid phase
C_{sw}	Surfactant concentration in water phase
C _{threshold}	Threshold concentration for surfactant in water phase
epdry	Foam model parameter in F2
epsurf	Foam model parameter in F1
<i>F</i> 1 to <i>F</i> 6	Dependent functions in the range of 0 to 1 in STARS model
$f_{g,avg.}$	Average foam quality
FM	Mobility reduction factor
fmdry	Foam model parameter in F2
fmmob	Reference to the maximum gas mobility reduction that can be achieved
fmsurf	Foam model parameter in F1
k_{ra}^{f}	Relative permeability of gas phase in the state of foam
k_{rg}^{nf}	Relative permeability of gas phase in absence of foam
k_{rg}^{o}	End-point relative permeability of gas phase
k_{rw}	Relative permeability of water phase
k_{rw}^{o}	End-point relative permeability of water phase
K_{ii}^*	Dispersion tensor of species <i>i</i> in phase <i>j</i>
K_{sa}^*	Dispersion tensor of species surfactant in gas phase
K_{su}^*	Dispersion tensor of species surfactant in water phase
K _{saw}	Partition coefficient of surfactant between gas phase and water phase
L	Length of 1-D formation
n_q	Corey exponent for gas phase
n_w	Corey exponent for water phase
$\overrightarrow{N_{i}}$	Flux of species i
N_n^{i}	Number of phases
NX	Number of grid blocks
p	Pressure
p_{q}	Gas pressure
p_w	Water pressure
Pe_{g}	Peclet in gas phase
Pe_w	Peclet number in water phase
S_{ar}	Residual gas saturation
S_i	Saturation of phase j
S_w	Water saturation
S_{wr}	Residual water saturation
TPV	Total pore volume of injection
R_i	Generation and consumption term in conservation equation
t	Time
$\overrightarrow{u_j}$	Superficial velocity of phase j
u_{g}	Superficial velocity of gas phase
5	

u_w	Superficial velocity of water phase
ν	Interstitial velocity
W_i	Total mass of i in bulk volume
W_{g}	Total mass of gas in bulk volume
W_w	Total mass of water in bulk volume
x	Distance
ϕ	Porosity
$ ho_{j}$	Density of phase j
$ ho_g$	Density of gas phase
$ ho_s$	Density of solid phase
$ ho_w$	Density of water phase
ω_{ij}	Mass fraction of species i in phase j
ω_{is}	Mass fraction of species i in phase solid phase
μ_{app}	Apparent Viscosity of foam
μ_{g}	Viscosity of gas
μ_w	Viscosity of water

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