RICE UNIVERSITY

SURFACTANT/FOAM ENHANCED AQUIFER CONTACTING AND MODELING FOR AQUIFER REMEDIATION

by

BUSHENG LI

DOCTOR OF PHILOSOPHY

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Surfactant/Foam Enhanced Aquifer Contacting and Modeling for Aquifer Remediation

by

Busheng Li

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MARCH, 2006
ABSTRACT

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Experiments and numerical simulations were carried out to improve the understanding of foam flow in underground porous media, especially three-dimensional foam flow, and to develop a numerical model for the design of the foam hydrogen sparging process for aquifer remediation. Injection of hydrogen is a promising method to enhance in situ anaerobic biodegradation of chlorinated solvents. The use of foam formed in situ by injection of hydrogen and a suitable surfactant solution greatly extends the horizontal migration of hydrogen in the subsurface, especially near the bottom of the aquifer where chlorinated solvents normally reside. The number of hydrogen injection wells required is thereby reduced.

Experiments were conducted in a 2x2x2 foot glass tank filled with sand and instrumented to permit sampling or measurement of local pressure differences as a function of time at 36 points located at 9 lateral positions and four elevations. After the tank was filled with surfactant solution, gas was injected at constant pressure from
one corner near the bottom of the tank. In some experiments the packing of the sand was homogeneous; in others it was layered. The experiments confirmed that foam greatly increases lateral gas distribution along the bottom as well as average gas saturation in the tank.

A model was developed to simulate three-dimensional foam flow in porous media and was incorporated into the existing reservoir simulator UTCHEM. The model changes the gas relative permeability curve and gas viscosity from those of ordinary two-phase flow to represent the reduced gas mobility when foam is present. All except one parameter of the model can be obtained from foam experiments in one-dimensional sand columns. This parameter is a geometric factor, which accounts for the greater mobility of foam in three dimensions than in one dimension for similar conditions, presumably the result of the greater number of possible flow paths in three dimensions. A history match of several of the above tank experiments showed that if foam mobility in the tank was taken to be about five times greater than in a column, simulated average gas saturation, gas injection rate, gas distribution and pressure profile six inches above the bottom of the tank were in good agreement with experimental results for the homogeneous packing. For the layered packing it was also necessary to fit another parameter to the data to account for generation of additional foam by flow of gas from lower to higher permeability regions.
The simulator was used to design a foam hydrogen sparging process for a hypothetical aquifer. Results showed that with foam well spacing could be increased by 80% for a particular homogeneous aquifer while maintaining about the same sweep efficiency near the bottom of the aquifer.
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Chapter 1

INTRODUCTION

Foam has long been used in various industry areas such as food, mining and petroleum. Of particular interest here is that it has been used in a wide range of subsurface applications, including gas diversion in IOR process, acid diversion for well stimulation and liquid and gas diversion in environmental remediation. The research work of this thesis will mainly focus on the application of foam to aquifer remediation.

1.1. General description

DNAPL (dense non-aqueous phase liquid) is a persistent source of groundwater contamination, with very few of the existing groundwater remediation techniques offering effective remediation. Surfactant flooding is one of the most promising technologies. The use of foam as a mobility control agent improves surfactant sweep efficiency, hence increasing the effectiveness of the process [Hirasaki, Miller et al., 1997, 2000]. Hydrogen sparging of aquifers contaminated with chlorinated solvents has shown promise as a method to enhance microbial dechlorination in situ [Newell et al, 2000, 2001]. The major concern in the application of this remedial approach is the ability to distribute hydrogen effectively throughout the contaminated interval such that
complete dechlorination can occur. Because of the low density and viscosity of hydrogen compared to water, the horizontal and vertical extent of residual gas saturation formation during hydrogen sparging is limited to only a small, conical region around and above the screened interval. A promising method to improve hydrogen contact throughout a contaminated interval-and to greatly extend the horizontal migration of hydrogen in the subsurface-is to deliver the hydrogen as an "in situ generated foam", a dispersion of gas in water that is stabilized from coalescence by the presence of a small amount of surfactant. It is generated by injection of a slug of dilute surfactant solution into the well, followed by gas injection. The gas bubbles that form are inhibited from coalescence by the surfactant adsorbed at the interfaces, and the lamellae or "soap films" between the bubbles increase the resistance of the gas to flow through porous media. More details of foam application for aquifer remediation will be discussed in Chapter 3.

The applications of foam are always 3-dimensional on a field scale. However, most previous research focuses only on properties of foam in 1-dimension. One aspect of this research work focuses on investigating the properties of 3-dimensional foam to gain better understanding of foam flow in porous media, especially aspects related to aquifer remediation, and to provide a general guideline for the process design. 3-D experiments were performed and results are discussed in this thesis.
Another aspect of this research work focuses on the modeling and design of the surfactant/foam process for aquifer remediation. A foam simulation model is proposed to simulate 3-dimensional foam flow and a hypothetical field foam application is designed.

1.2. Thesis outline

This thesis is organized into eight chapters, including the introduction presented in this chapter.

Chapter 2 describes the technical background of this thesis. The background information on foam transport in porous media is presented. Foam formation and decay mechanisms are among the topics discussed.

Chapter 3 introduces the background on the application of foam in aquifer remediation. The DNAPL problem, surfactant enhanced aquifer remediation (SEAR) with foam to improve sweep efficiency and foam-enhanced hydrogen biosparging in biodechlorination processes are among the topics discussed.

Chapter 4 provides the experimental results obtained from the 1-D surfactant screening and 2-D sandpack foam experiments. A surfactant solution with favorable foamability
was determined by performing the surfactant screening experiments. Foam effects on gas flow were demonstrated in the 2-D preliminary foam experiments.

Chapter 5 investigates the flow properties of 3-D foam. Effect of injection pressure, different injection strategies and the stability of foam are investigated in homogeneous and heterogeneous 3-D laboratory sand packs. Experimental results in the much larger Rice ECRS tank are also provided.

Chapter 6 presents a simulation model for foam flow in porous media. This model uses parameters obtained from 1-D column foam experiments to simulate the 3-D foam flow. Most of the simulation parameters can be obtained from 1-D column experiments and only one parameter needs to be determined from 3-D history match simulation. The model is incorporated into the reservoir simulator UTCHEM.

Chapter 7 discusses the design of a hypothetical foam field application for aquifer remediation. A hypothetical aquifer is studied and issues which need to be considered when performing a foam field application are discussed in this chapter.

Chapter 8 gives the conclusions obtained from the study of this project and recommendations for future research work.
Chapter 2

TECHNICAL BACKGROUND

Besides of the use of foam in oil recovery, it can also be used in other oil-field operations: for drilling and cleaning out wells and for hydraulic fracturing of impermeable formations. Currently, about 9% of world oil production, and virtually all enhanced oil recovery (EOR), comes from injecting gases, primarily steam, methane and carbon dioxide, into oil reservoirs. Both steam and CO₂ processes can be nearly 100% efficient within rock strata in locations where the gases contact oil. But the actual oil recoveries are much lower because the gas contacts and sweeps only a small portion of the reservoir and its oil, that is, sweep efficiency is poor. Two major causes of poor sweep efficiency are the low viscosity of injected gases and geological differences between reservoir layers. Foam can improve the sweep efficiency of injected gases by mitigating or reducing the effects of low gas viscosity and reservoir layering.

In porous media, foam exists as gas bubbles whose shapes conform to the solid matrix. Hirasaki [1989] defined foam in porous media as “a dispersion of a gas in a liquid such that the liquid phase is continuous (i.e. connected) and at least some part of the gas phase is made discontinuous by thin liquid films called lamellae.” Surfactant stabilizes
Figure 2.1 A particular type of molecular structure performs as surfactant

the liquid lamellae, keeping the gas phase discontinuous, and gives rise to the reduction in gas mobility. The presence of low-mobility gas also reduces the relative mobility of the liquid phases. The reduction in mobility, i.e. increased resistance to flow, for both gas and liquid phases is the most important foam property that has been utilized in various applications. This chapter gives a review on the nature of foam in porous media.

2.1 Surfactants

The term “surfactant” comes from a contraction of “surface active agents”. A surfactant is briefly defined as a material that can greatly reduce the surface tension of a liquid (usually water) when used in very low concentrations. Surfactants are enriched at the surface or interface between phases [Miller and Neogi, 1985]. They have been known to people for a long time in the form of soaps.

Figure 2.1 shows a particular type of molecular structure which performs as a surfactant. This molecule is made up of a water soluble (hydrophilic) and a water
insoluble (hydrophobic) component. The hydrophobe is usually the equivalent of an 8 to 18 carbon hydrocarbon, and can be aliphatic, aromatic, or a mixture of both. The sources of hydrophobes are normally natural fats and oils, petroleum fractions, relatively short synthetic polymers, or relatively high molecular weight synthetic alcohols. The hydrophilic groups give the primary classification to surfactants, which are anionic, cationic and non-ionic in nature. The anionic hydrophilic acids are the carboxylates (soaps), sulphates, sulphonates and phosphates. The cationic hydrophiles are some form of an amine product. The non-ionic hydrophilic acids associate with water at the ether oxygens of a polyethylene glycol chain. In each case, the hydrophilic end of the surfactant is strongly attracted to the water molecules and the force of attraction between the hydrophobe and water is only slight. As a result, the surfactant molecules align themselves at the surface, forming a monolayer in which the hydrophilic end is toward the water and the hydrophobe is squeezed away from the water.

When the surfactant concentration is low, all the rest of the surfactant molecules are dissolved in the solution as individual surfactant monomers. With increasing surfactant concentration, at some particular surfactant concentration, some of the surfactant molecules will form aggregates which are called micelles [Miller and Neogi, 1985]. The micelles are in the form where the hydrophobes form the interior and the hydrophilic are exposed to the surrounding water. The concentration at which micelles are formed is called the critical micelle concentration (CMC). When surfactant concentration is
lower than CMC, the interfacial tension will decrease significantly with increasing surfactant concentration. After the surfactant concentration exceeds CMC, however, there will be only small changes in the value of interfacial tension with increasing surfactant concentration. Though the interfacial tension does not change much with the changing of the surfactant concentration after it exceeds CMC, the higher surfactant concentration will result in more micelles. Micelles can solubilize non-polar materials by enclosing them in their hydrophobic interiors, thereby increasing the solubility of oil or other non-polar materials in water.

Foams are dispersions of gas bubbles in liquids. Such dispersions are normally quite unstable and will quickly break in less than a second. But if surfactants are added to the liquid, they can greatly improve the bubble stability so that some foams can persist indefinitely.

2.2 Fundamentals of flow in porous media

2.2.1 Darcy’s Law for one phase and multiphase flow

In 1856, Henri d’Arcy originally developed a phenomenological law to describe flow in porous media at low Reynolds numbers, which is called Darcy’s law. He investigated
the flow of water in vertical homogeneous sand filters in connection with the fountains of the city of Dijon, France. From his and subsequent experiments, the following equation has been derived to describe the flow:

\[ u = -\frac{k \Delta p}{\mu \Delta x} \]  \hspace{1cm} (2-1.a)

If flow is not horizontal, then the gravity force should also be considered:

\[ u = -\frac{k}{\mu} \left( \frac{\Delta p - \rho g \Delta h}{\Delta x} \right) \]  \hspace{1cm} (2-1.b)

where \( \Delta h \) is the height difference along \( \Delta x \).

These equations (Eq 2.1a and 2.1b) apply only to one phase flow in porous media. It shows the relationship among 5 parameters when fluid flows through a porous medium. In this equation, terms \( k \) and \( \mu \) are the properties of the porous medium and the fluid correspondingly: \( k \) is the permeability of the porous medium and \( \mu \) is the viscosity of the fluid. In general, people usually define the term \( k/\mu \) as the mobility of fluid in the porous medium and it can be represented by the symbol \( \lambda \). In this equation, the velocity \( u \) is the superficial velocity which is calculated from the volumetric flow rate divided by the entire cross-section area of the porous medium: \( u = q/A \). It is also
called as the Darcy velocity. The velocity inside the porous medium is affected by the pore structure. So, the interstitial velocity $v$ is calculated from the superficial velocity $u$ by dividing it by the porosity $\phi$ of the porous medium: $v = u / \phi$.

In three dimensions, the flux and the potential gradient are vectors and the permeability is a second order tensor. Darcy’s law is expressed as:

$$u = -\frac{K}{\mu} \nabla \Phi$$  \hspace{1cm} (2-2)

where $K$ is the permeability tensor and $\Phi$ is the flow potential which is defined as:

$$\Phi = p - g \int_{D_0}^{D} \rho \, dD \equiv p - \rho g (D - D_0)$$  \hspace{1cm} (2-3)

where $D$ is the depth with respect to some datum such as the mean sea level. When applied to multiphase flow, Darcy’s law can be written for each phase $l$ as:

$$u_l = v_l \phi = \frac{k \cdot k_r(S_l) \Delta p_l - \rho_l g \Delta h}{\mu_l} \frac{\Delta x}{\Delta x}$$  \hspace{1cm} (2-4)

In this equation, the term $k \cdot k_r(S_l)$ is the effective permeability of the porous medium. $k_r(S_l)$ is the relative permeability of phase $l$ and it is a function of the phase saturation.
Figure 2.2 Pore level schematic of foam in porous media
After Gillis and Radke [1990]

$S_r$. And just as in the one-phase Darcy’s law, we call the term $k \cdot k_{rl} / \mu_l$ the mobility of phase $l$ in the porous medium and it can be expressed using the term $\lambda_{rl}$.

2.2.2 Foam flow in porous media

When foam flows in a porous medium, it is not a separate phase by itself. It is a dispersion of gas in liquid where liquid phase is continuous but the gas phase is discontinuous. So when we consider foam flow in a porous medium, we should consider it as separate flows of gas and liquid. Figure 2.2 shows a mechanistic picture
of foam flow in a porous medium. From this figure we can see the three different gas flow conditions; gas flows in two ways, either continuously or discontinuously. The rest of the gas is trapped and does not move.

2.2.2.1 Gas mobility reduction by foam

The reduction of gas permeability and the increase of gas apparent viscosity are the two main reasons why foam can produce gas mobility reduction effect. The trapping of gas in the porous medium is one reason for the reduction of gas permeability. The trapped gas will result in the blockage of gas pathways and thus reduce the effective permeability of gas. According to Bernard et al [1965], the amount of gas trapped after a foam flood can be as high as 70%. In our 1-D column foam flooding experiments described in detail later, we also found the trapped gas saturation to be as high as 70%. And in these experiments, under the same conditions, 200 darcy sand had higher residual gas saturation than 40 darcy sand (darcy is an unit of permeability which is a property of the porous medium, 1 darcy = 0.987 μm²)

The gas apparent viscosity will be increased because of the presence of foam. For weak foams, most of the gas will flow in continuous gas paths and the flow resistance from discontinuous gas is very small. So weak foams can only cause small mobility reduction, and the trapping of gas in the porous medium may be the main or only mechanism that
reduces gas mobility. For strong foams, a large portion of the flowing gas will flow discontinuously because when foam is strong, the generated lamellae will block all the flow paths in the porous medium. Consequently, the flowing gas bubbles will flow in so-called "bubble trains," as shown in the central portion of Figure 2.2. Flow of the bubble trains will have much higher resistance compared to continuous gas flow. Therefore, the discontinuous foam has a much higher effective viscosity compared to continuous gas.

The processes of foam trapping and mobilization in porous media are intermittent. When foams flow in a porous medium, none of the discontinuous gas is always trapped or always moving. With the mobilization of the lamellae, bubbles can switch to flowing or blocking a channel because of the changes in the flow paths [Kovscek and Radke, 1994]. So the trapped gas and bubble trains exist only in a time-averaged sense. Moreover, increasing the pressure gradient will generate new flow channels which originally were filled with trapped gas and create new bubble trains. So foam flow is non-Newtonian and can be shear thinning. Many investigators have experimentally confirmed the shear-thinning nature of foam [Hirasaki and Lawson, 1985; Falls et al., 1989]. In some pressure gradient range, increasing the pressure gradient will also produce the generation of more lamella which will bring more resistance to gas flow.
There are many factors that govern the process of foam trapping and mobilization, e.g. pressure gradient, pore geometry, foam texture, bubble-train length and gas velocity. Among them the foam texture (lamella density) is the most important parameter which determines gas mobility in the porous medium. When foams flow in a porous medium, there exists a minimum pressure gradient $\nabla p^\text{min}$ below which discontinuous gas will remain trapped. When the pressure gradient rises above $\nabla p^\text{min}$, the discontinuous gas begins to flow. The flowing fraction of gas will increase with increasing of pressure gradient. In this process, the lamella density determines the value of $\nabla p^\text{min}$: the higher the density, the larger the value of $\nabla p^\text{min}$. So, foam texture (lamella density) is a crucial parameter which determines the relative amounts of gas moving in bubble-trains and trapped gas [Alvarez, 1998], and thus the mobility.

2.2.2.2 Water mobility in the presence of foam

It is generally agreed that foam does not affect the water relative-permeability function. This is because water is the wetting phase, and it will still occupy the same smaller pores which it occupies in the absence of foam. Many researchers have proved this [Bernard et al. 1965; Friedmann and Jensen, 1986; Osterloh and Jante, 1992]. However, foam flow can change the value of water relative permeability indirectly
because during foam flow water saturation will be change, which will thereby change the magnitude of water relative permeability.

2.3 Mechanisms of foam formation and destruction

There are three fundamental pore-level generation mechanisms of foam: snap-off, division, and leave-behind. In general, leave-behind can only generate weak foam because the generated lamella is oriented parallel to the direction of flow. Snap-off and division are the two mechanisms which can generate strong foam. Under conditions of coinjection of surfactant solution and gas, snap-off is the dominant foam generation mechanism.

2.3.1 Snap-off

Snap-off is a very significant mechanism for bubble generation in porous media. Snap-off is not restricted to the creation of trapped liquid globules. It repeatedly occurs during unsteady multiphase flow in porous media regardless of the presence or absence of surfactant. Hence, snap-off is recognized as a mechanical process. Figure 2.3 illustrates a gas finger that enters a pore constriction initially filled with wetting liquid. Upon reaching the throat, the interface curvature and corresponding capillary pressure rise to the equilibrium entry value. As the bubble front enters the downstream body,
Figure 2.3  An invading non-wetting phase passing through a pore constriction

When the pressure difference across the interface at the throat \( P_{cT} \) is greater than the pressure difference at the leading surface \( P_{cF} \), Snap-off will occur

the curvature and corresponding local capillary pressure at the bubble front fall with expansion of the interface. The resulting gradient in capillary pressure initiates a gradient in liquid pressure directed from the pore-body toward the pore-throat. Liquid is then driven to the pore-throat where it accumulates and finally forms the foam bubble.

To get snap-off, the pressure difference across the interface in the throat \( P_{cT} \) in Figure 2.3) must be greater than that at the leading surface \( P_{cF} \) in Figure 2.3). Also, the saturation of the wetting phase must be high enough for snap-off to occur. According to Falls et al. [1988], the critical capillary pressure for snap-off in bead packs is about half of the capillary entry pressure, \( P_{c}^{*n} \approx \frac{1}{2} P_{c}^{*} \). In a straight capillary tube, Rayleigh
instability also causes the formation of a liquid bridge at exactly one half of the capillary entry pressure \( P_{c}^{sn} = \frac{1}{2} P_{c}^{e} \).

The requirement for snap-off to occur is low capillary-pressure inside the pore space. But before snap-off can occur, the capillary pressure must be at least as high as the capillary entry pressure \( P_{c}^{e} \) for gas to flow into the pore constriction. After that, the capillary pressure must drop to equal or below \( P_{c}^{sn} = \frac{1}{2} P_{c}^{e} \) for snap-off to occur. Rossen [2000] proposed that in a homogeneous porous medium, snap-off can occur only when there is an increase in water saturation or local, temporary, non-equilibrium reduction in capillary pressure. And he pointed out that repeated snap-off is not likely in homogeneous media. It will stop after the downstream capillary pressure increases, which means the pore spaces are filled with bubbles. Snap-off in homogeneous media also occurs when gas is flowing upward [Falls et al., 1988]. It takes place perhaps because of gas fingers becoming unstable when the viscous pressure gradient is less than the hydrostatic pressure gradient. Radke et al [1990] investigated the condition for snap-off from the pore geometry aspect. Their analysis showed that for snap-off to occur, the pore body radius should be at least twice the pore throat radius. Ransohoff and Radke [1988] investigated the effect of flow rates on snap-off. They found that snap-off occurs in homogeneous media when flow rate is high. They argued that the higher rate causes gas to be able to invade the smaller pore constrictions and the
favorable geometry for snap-off is found only for these smaller constrictions. Strong foam can be generated after gas enters these sites. But here one should be aware that the low capillary pressure requirement for snap-off may not be satisfied at high gas flow rates. The favorable geometry alone cannot guarantee the occurrence of snap-off and high flow rate is not a requirement for snap-off. Many researchers [e.g. Owete and Brigham, 1987; Falls et al., 1988; Ransohoff and Radke, 1988; Tanzil, 2002] observed that snap-off is enhanced in heterogeneous media. When gas flows from a region of lower to a region of higher permeability, capillary pressure decreases. If it becomes sufficiently low, snap-off occurs.

Snap-off is a very important foam generation mechanism because it can occur at low flow rates and it results in discontinuous-gas foam. It depends on several parameters such as capillary pressure (hence saturation), pore geometry, and wettability of the porous medium. Since it is a mechanical process, it is largely independent of surfactant formulation except for relative small difference among surfactants in altering surface tension.

2.3.2 Division

The second mechanism of strong foam generation is lamella division. Figure 2.4 shows the process of how division occurs: when a moving lamella train encounters a branch
in the flow path, it may split into two lamellae, one flowing into each branch. The most important factor in the process of division is that the pressure gradient should become large enough to mobilize the lamellae. Division also depends on the pore geometry and bubble size. If the bubble size is smaller than the pore size, division does not occur and the lamella will flow into only one branch. Moreover, if a single flowing lamella train is surrounded by stationary lamellae, then there will be no branching and thus no division. Lamella division depends on pressure gradient and is proportional to gas velocity [Falls et al. 1988]. Because lamella division can generate lamellae which are not parallel to the flow direction and thus generate discontinuous gas foam, it can result in strong foam and greatly increase the gas apparent viscosity, just like snap-off.

2.3.3 Leave-behind

Figure 2.5 shows the process of how leave-behind occurs. When two gas fingers invade adjacent liquid-filled pore bodies, liquid between them is left behind and a foam lamella
Figure 2.5 Foam formation by leave-behind
(lamella is parallel to the flow direction)

generated [Kovscek and Radke, 1994]. The stability of the left-behind lamella is mainly
affected by two factors: the capillary pressure and the pressure gradient. If the capillary
pressure is not too high (which means the liquid saturation is sufficiently high) and the
pressure gradient is not high, the left-behind lamella will be stable. Unlike snap-off and
lamella division, the leave-behind mechanism can result only in continuous gas or weak
foam. This is because the lamellae generated by leave-behind are parallel to the
direction of flow and do not provide much resistance to the gas flow in the porous
medium.

2.3.4 Comparing these three mechanisms

Following the discussions above, we can see that among these three foam generation
mechanisms, only snap-off and lamella division can result in large reduction in gas
mobility (strong foam). This is because these two mechanisms can generate
discontinuous gas trains and increase the flow resistance of gas. When water saturation is sufficiently high, i.e. in co-injection of gas and surfactant solution, snap-off is the dominant mechanism [Kovscek and Radke 1994]. However, when the velocity or the pressure gradient is high, lamella division will likely become the dominant mechanism over snap off.

Kharabaf and Yortsos [1996] proposed a pore-network model to simulate foam flow. Their simulation shows that snap-off is dominant over leave behind mechanism. This is because the snap-off lamellae can make the gas discontinuous but the left-behind lamellae cannot. So even if more lamellae are generated by leave-behind than by snap-off, the foam strength is only determined by snap-off lamellae. The limitation of their pore-network model is that they did not include the lamella division mechanism.

2.3.5 Foam destruction

There are two basic mechanisms which may cause the destruction of foam film: capillary-suction and gas diffusion.

For gas diffusion in foam, according to the Young-Laplace equation, gas on the concave side of a curved foam film is at a higher pressure and hence, it will diffuse from bubbles with larger curvatures to bubbles with smaller curvatures. In porous
media, lamella curvature depends on pore dimensions and on location within the pore space. Gas diffusion drives lamellae to pore-throats to achieve an equilibrium state of zero curvature. Kovscek and Radke [1994] found that foam coalescence then occurs only when two lamellae happen to reach the same pore throat. As the possibility of this is relatively low in a porous medium, gas diffusion is relatively unimportant in determining foam coalescence.

The most important destruction mechanism for foam in porous media is coalescence by capillary suction. Thin lamellae collapse because they are not thermodynamically stable. The existence and destruction of the lamellae are governed by the film disjoining pressure \( \Pi \), which was first introduced by Derjaguin and co-workers [1936, 1939]. It is the combined effect of repulsive and attractive forces within a lamella [Miller and Neogi, 1985] and a function of film thickness \( h \). When there is no surfactant in the solution, the attractive Van der Waals forces are the dominant force which will result in negative disjoining pressure. The thin film will collapse immediately under such negative disjoining pressure. When ionic surfactant is added to the solution, the lamella will be stabilized because of the adsorption of surfactant at the two-phase (gas/liquid) interface. This adsorption will result in an electrical double-layer and generate excess repulsive forces which can stabilize the thin lamella film. According to Kovscek and Radke [1994], these stabilizing effects depend on the surfactant concentration, surfactant structure, and the ionic content of the aqueous solution.
For a static film in equilibrium at a flat interface, the disjoining pressure is equal to the capillary pressure. For a thin film which has thickness of $h$ (as shown in Figure 2.6), for a drainage process, during gas injection, wetting-liquid saturation will decrease and the capillary pressure will increase. With increasing capillary pressure, the film thickness will decrease. When it reaches the critical film thickness $h_{cr}$ and continues to become thinner, the capillary pressure will exceed the maximum disjoining pressure, $\Pi_{\text{max}}$, and the static film ruptures.

For a flowing lamella in the porous medium, the coalescence process is more complicated compared to that for a static lamella. Figure 2.7 shows a sketch of this process: a moving lamella flows from a pore body to a pore throat and then to another
Figure 2.7 A mobile foam lamella passing through a periodically constricted tube

Coalescence occurs at $t_3$. From Kovscek and Radke [1994]

pore body. During this process, the lamella will undergo squeezing forces and stretching forces. If during stretching, the thickness of the moving lamella falls below the critical film thickness $h_{cr}$, the lamella will rupture [Jimenez and Radke, 1996; Singh et al., 1997]. Therefore, a moving thin film could rupture at a limiting capillary pressure $P_c^*$ which is less than the maximum disjoining pressure $\Pi_{\text{max}}$. That means moving lamellae can be even less stable than static ones.

The influx of liquid into a moving lamella from its surroundings will determine whether the lamella thickness can fall below $h_{cr}$. If the influx is rapid enough, the film thickness will be restored before it reaches the critical value $h_{cr}$. Surfactant properties and formulation are then an important factor in foam stability. For slow surfactant transport to the lamella surface, the stretching causes a reduction in surfactant concentration and an increase in the local surface tension. The increased surface
tension works against the thinning. Surface flow from the low surface tension area at the plateau border to the high-tension regime drags liquid along with it. Together with the disjoining pressure, this Marangoni effect is a restoring and stabilizing force in a lamella. It helps the restoration process [Lucassen, 1981].

Khatib et al. [1988] directly measured the limiting capillary pressure $P_c^*$ in 70 to 9000 darcy glass-bead packs during steady foam flow over a wide range of gas fractional flows from 0.1 to 0.99. They also investigated the effects of capillary pressure on foam in porous media. Foam was pre-generated so that its strength depended mainly on its stability. They found that the limiting capillary pressure decreases with increasing gas flow rate or absolute permeability. In addition, the limiting capillary pressure is affected by surfactant formulation.

Lamella collapse at the limiting capillary pressure can be a very important factor that governs foam flow under certain conditions. Without pre-generation, it generally becomes a governing factor only after sufficiently strong foam is generated by snap-off and/or lamella division. Furthermore, lamella collapse is not important when the capillary pressure is much less than $P_c^*$ (or water saturation is much greater than $S_w^*$).
Chapter 3

FOAM APPLICATION ON AQUIFER REMEDIATION

Numerous military and industrial sites are contaminated with trichloroethene (TCE) and other chlorinated solvents. These contaminants will act as long-term sources by slowly dissolving in groundwater that flows past. Pump-and-treat processes have proved unsuccessful in remediating these sites because they are unable to remove much of the liquid contaminants. The objective of this research is to assess the potential of hydrogen based foams to effectively contact contaminated aquifers with electron donors and support rapid reductive dechlorination processes. The experimental results will provide the basis to evaluate this delivery system for field applications. Specifically, studies will be conducted to investigate foam application in source zones or immediately down gradient of source zones where the volumes of contaminated aquifers to be contacted are not prohibitive.

3.1 The DNAPL problem and SEAR process

DNAPL (dense non aqueous phase liquid) contamination is now a common source of groundwater contamination, especially in industrialized countries. It comes from a variety of industrial activities, such as degreasing, metal stripping, chemical
manufacturing, and wood treatment operations [Bedient et al., 1994]. Among DNAPL contaminants, the denser-than-water chlorinated organic compounds make up the largest portion. They are also the most common groundwater pollutants in North America [Fountain, 1998b].

DNAPL released at the surface will percolate downward into the subsurface. It tends to sink to the bottom of the aquifer because it has high density and will form DNAPL pools if there exist low-permeability stratigraphic units (Figure 3.1). The solubility of DNAPL in water is usually far above acceptable drinking water standards, but low
enough to make the DNAPL pool persist as a long-term source zone of a dissolved-phase groundwater contamination plume.

The biological and physicochemical properties of DNAPL complicate the remediation process of DNAPL source zone. Although some chlorinated compounds have been shown to biodegrade, direct degradation in the DNAPL phase is unlikely. DNAPL removal by dissolution is also limited by its low solubility in water. In addition, its high interfacial tensions create large capillary forces that limit DNAPL mobility. Therefore, most conventional aquifer remediation techniques such as pump-and-treat become ineffective on removal of all or nearly all of the liquid chlorinated solvent from a contaminated groundwater aquifer [Mackay and Cherry, 1989].

Surfactant-enhanced aquifer remediation (SEAR) is a most promising technology for DNAPL source zone remediation. This method comes from a similar surfactant application in the petroleum industry. The application of surfactants to recover crude oil from underground petroleum fields has been studied since the 1960's. Because of a surfactant’s surface-active nature, it will reduce the interfacial tension between oil and the displacing fluid and then recover the oil which was trapped in the porous media [Miller and Qurubuddin, 1987]. The principles and technology of surfactant-enhanced oil recovery are applicable in addressing environmental problems. Surfactants offer the
possibility of DNAPL removal by solubilization and/or mobilization of the DNAPL source zone and can be used to facilitate the recovery of organic contaminants (DNAPLs) from the subsurface. Surfactant can lower the interfacial tensions of DNAPL which will reduce the capillary forces. With the decreasing of the capillary forces, the DNAPL mobility will increase. In addition, surfactant molecules form aggregates called micelles above a critical micelle concentration (CMC). The micelles are capable of carrying some DNAPL in their cores, creating a substantial increase in the apparent solubility of DNAPL in the aqueous phase.

In a field test of surfactant for DNAPL source zone remediation at Hill Air Force Base, Utah, which was conducted by the University of Texas [Brown et al., 1999], the results showed that the SEAR method is capable of recovering most of the DNAPL from the pool. About 99% of the DNAPL was recovered with 3 pore volumes of 8% (v/v) sodium dihexylsulfosuccinate surfactant injected.

However, a significant limitation of the SEAR process is that the injected fluids flow preferentially in zones of high hydraulic conductivity in a heterogeneous aquifer. In fact, most of the injected fluids continue to flow through these high permeability regions even after they have been cleaned. Only a small portion of the injected surfactants flow through the low permeability regions of the aquifer which remain
contaminated. Fountain [1998a] reported a surfactant field test in a highly heterogeneous test cell in Lake Charles, Louisiana. DNAPL recovery was slowed significantly because of low sweep efficiency as demonstrated by their partitioning interwell tracer test (PITT) results. As a result, the time and cost of remediation are much higher than in a homogeneous aquifer and the total quantity of surfactants of other materials introduced into the subsurface is greater. One possible solution for this problem is using foam to perform the mobility control in the subsurface porous media. This will be discussed below.

3.2 Role of foam in aquifer remediation

3.2.1 Foam application on surfactant/foam process

Foam has been used as a mobility control agent in a variety of underground processes in the petroleum industry. It was first investigated for Enhanced Oil Recovery (EOR) purposes, such as steam-drive and CO₂-flood. It has been used since 1976 to control the gravity over-ride of injected gas over more dense and viscous oil [Hirasaki, 1989]. By dispersing the gas as a discontinuous phase with surfactant-stabilized foam lamellae, the gas has a much higher apparent viscosity and thus generates a larger pressure gradient to displace oil rather than bypassing oil. This in situ generated foam has been
used to improve oil recovery by steam, methane, and CO₂ injection. Foam improves the performance in these gas injection processes by reducing the mobility of the injected gas and diverting the gas into low permeability zones. This application of foam continues to be an active area of research in the oil industry as evident from recent publications [Li and Rossen et al, 2005; Shan et al, 2004; Blaker, et al., 2002; Mannhardt, et al., 2000; Kuhlman, et al., 2000; Berlin, et al., 2000; Myers, et al., 1999; Valera, et al., 1999; Rossen, 1999]. The knowledge gained from enhanced oil recovery is now being used for removing NAPL from aquifers [Pope and Wade, 1995]. In aquifer remediation, the main objective of the surfactant/foam process is to improve process performance in a heterogeneous aquifer by providing a more uniform sweep of the formation. After an initial slug of an aqueous surfactant solution is injected into the aquifer, gas (typically air) is injected to generate foam. Because both the injected surfactant solution and air enter mainly the high permeability zones, foam is generated in these zones by air injection. The generated foam will increase the resistance to flow of liquid there. Then, when additional surfactant solution is injected, a larger portion of it will enter the low permeability zones and increase the surfactant sweep efficiency. Such applications can be found in matrix acidizing processes where foam is used to divert acid into less-permeable zones [Zerhboub et al., 1994].

The first field demonstration of surfactant/foam process for aquifer remediation of DNAPL source zone was performed by our research group [Hirasaki, Miller et al., 2000]
at Hill Air Force Base, Utah, in Spring 1997. The test successfully demonstrated the applicability of the surfactant/foam process in an unconfined aquifer. In this contaminated aquifer, DNAPL was present only along the base of the aquifer and soil sampling showed much higher permeability sands that could act as “thief zones” for the injected fluids. The field test had injection and extraction wells spaced 20 feet apart with two multi-level sampling monitoring wells in between. Foam was generated in situ with only a modest increase in injection pressure. It was propagated horizontally in the direction of flow and surfactant was diverted to the contaminated interval at the bottom of the aquifer. The presence of DNAPL was reduced to a low level using 3 pore volumes of 4% v/v sodium dihexylsulfosuccinate. The remaining DNAPL saturation in the test area was at about the same level as Brown et al. [1999] while using only about 60% of the amount of surfactant. The surfactant/foam process was successful in reducing the average DNAPL saturation of the swept pore volume to 0.03%. Also, a comparison of the gas injection simulation results between foam and no-foam situations showed that without foam, much of the base of the aquifer could not be contacted by gas [Tanzil, 2001].

3.2.2 Foam application on hydrogen biosparging

In addition to removal of DNAPL from source zones, reductive dechlorination by hydrogen biosparging can be used to degrade the dissolved chlorinated hydrocarbons
in the plume down gradient from the source zone. Direct hydrogen addition, wherein hydrogen is delivered without the use of fermentation substrates or carbon sources is an in-situ bioremediation technology for chlorinated solvent plumes [Hughes et al. 1997].

3.2.2.1 Background of dechlorination process

Reductive dechlorination of chlorinated ethenes is a process commonly observed in anaerobic aquifers. Dechlorination occurs as result of microbial activity and can be catalyzed by a variety of organisms [Damborsky 1999; El Fantroussi et al. 1998]. Hydrogen is now widely recognized as a key electron donor required for the dechlorination process. Hydrogen acts as an electron donor and halogenated compounds such as chlorinated solvents act as electron acceptors that are reduced in the reductive dechlorination process. To enhance beneficial anaerobic processes for the purpose of bioremediation, numerous research groups have focused on methods to increase the supply of electron donor (hydrogen) to the dechlorinating bacteria. Most researchers and technology developers have focused on adding an indirect electron donor (such as lactate, mulch, edible oil or other carbon source) that can be fermented by some bacteria to produce hydrogen for the dechlorinators. However, direct delivery of dissolved hydrogen to the subsurface [Hughes, et al. 1997] is another effective way to increase the supply of electron donor to the dechlorinating bacteria. This ‘direct’
method is simpler and costs are lower compared to other ‘indirect’ methods. One concern about this method is that, the high hydrogen partial pressures caused by direct hydrogen gas addition will diminish the levels of dechlorination activity. Carr and Hughes [1998] assessed the development and sustainability of rapid dechlorination at high hydrogen partial pressures and demonstrated that despite the high hydrogen levels, continuous improvement in dechlorination rate, dechlorination extent, and dechlorination efficiency occurred throughout the approximately 500 days of testing. In their systems, the availability of PCE appeared to become the limiting factor for increasing dechlorination efficiency. It was proved that halorespiring organisms are capable of sustained rapid activity at substantial hydrogen partial pressures. This implies that the direct hydrogen application method is promising and the ability to contact contaminants will determine the success of the bioremediation processes.

3.2.2.2 Foam enhanced hydrogen biosparging

Hydrogen can be delivered to the aquifer for reductive dechlorination by sparging with an injection well as is done during biosparging. Thus the practice of hydrogen biosparging can build on air sparging technology. Similar to air sparging, the controlling factor in the success of hydrogen reductive dechlorination is the distribution of the gas in the aquifer. In the presence of NAPL, achieving good hydrogen distribution may be a greater challenge than for air sparging of LANPL
Figure 3.2  Gas distribution in aquifer during sparging

because chlorinated solvents are DNAPL and thus are present at the bottom of the aquifer as pools or ganglia rather than at the water table.

Hydrogen has low density and viscosity compared to water. Thus the buoyancy gradient rather than the viscous pressure gradient will dominate the flow of hydrogen. Hydrogen injected at the base of the aquifer will form fingers of hydrogen, which migrate upward while simultaneously deflecting laterally as they encounter heterogeneity. Figure 3.2 illustrates the key problem with biosparging when contaminants exist as a DNAPL. The gas tends to rise and does not contact much of the DNAPL at the base of the aquifer. One role of foam is to promote the lateral transport of gas in the aquifer in order to contact the DNAPL at the base of the aquifer. If a significant amount of DNAPL is present, it may be advantageous to first produce
free-phase DNAPL and then inject surfactant solution to displace the residual DNAPL by solubilization and/or mobilization. In this case, air or hydrogen can first be used to generate foam to improve contacting of the aquifer with the surfactant solution. Following displacement of most of the DNAPL with the surfactant, dilute surfactant solution and hydrogen can continue to be injected intermittently to degrade any remaining chlorinated hydrocarbons that may diffuse from unswept tight regions or fractures in the aquitard.

Without foam, contaminants may pass undegraded between the injection wells in the region not contacted by gas. Foam will direct more hydrogen throughout the aquifer and thus form a more effective barrier. The lateral versus vertical movement of the foam was one of the key questions before the field test of the surfactant/foam process at Hill Air Force Base. There was some concern that the injected air might rise only in the vicinity of the injection well, as in air sparging. We speculated that the foam would have much greater resistance to flow perpendicular to the stratification than parallel. This speculation was based on earlier research on the mechanisms of foam generation [Falls, et al., 1988]. In fact, the aquifer heterogeneity caused the process to be more effective in transporting gas along the base of the aquifer. In an aquifer or reservoir, there always are different parallel layers which have different permeability. Because of this kind of heterogeneity, the foam mobility perpendicular to stratification is less than its parallel mobility. Tanzil [2002] investigated the difference in foam mobility between
a homogeneous and a heterogeneous system. Under the same experimental condition, in the homogeneous column, only coarse-textured foam was generated and the gravity over-ride was apparent. In the heterogeneous column, fine-textured foam was generated by the capillary snap-off mechanism as the gas exited the finer sand (the snap-off mechanism was discussed in Chapter 2). The fine texture foam had a low mobility (i.e., high apparent viscosity) and the viscous forces dominated the gravity forces, leading to piston-like displacement. The pressure drops across the homogenous and heterogeneous sand columns were also different. The pressure drop in the heterogeneous column was about 10 times greater than in the homogeneous column. His experiments proved that the resistance to flow is much greater in the direction perpendicular to stratification than along homogeneous strata. This will be an important factor in hydrogen foam sparging because it will promote the lateral distribution of hydrogen by increasing the resistance to vertical gas flow.
Chapter 4

SURFACTANT SCREENING AND 2-D FOAM EXPERIMENTS

The experimental results of the surfactant screening and 2-D sand pack are presented and discussed in this chapter. The purpose of 1-D column surfactant screening experiments is to test the foamability of chosen surfactants. For a surfactant to be effective in improving hydrogen biosparging, it must be capable of reducing the mobility of gas flowing through water-saturated sand. By measuring the reduction of gas mobility in a sand column at a specified surfactant concentration for different surfactants, it will be possible to compare candidate surfactants for application to H₂ foam. The candidate surfactants we chose include those that have already been evaluated for mobility control, either in aquifer remediation or enhanced oil recovery. Only surfactants exhibiting desirable foam properties were used in the dechlorination and solubilization tests. The purpose of the preliminary 2-D sandpack experiments is to verify the enhanced sweep efficiency by surfactant/foam flow. These preliminary 2-D results are useful in designing the following 3-D foam experiments.

4.1 1-Dimensional column experiments for surfactant screening
4.1.1 Experimental

A series of experiments was performed in a glass column to screen the foamability of surfactants. Surfactants were investigated from different aspects. First of all, the chosen surfactants were tested under the same experimental condition to find out the best foamer. Then some other factors which may affect the generated foam strength were also investigated, i.e. various mixture of surfactants, the total concentration of the surfactant solution and the shear thinning effect with velocity. The experimental column was 1 foot in length with 1 in. internal diameter. It was packed with 120 darcy F-32 sand obtained from US Silica (Berkeley Springs, WV). Diagram of the experimental apparatus is shown in Figure 4.1. The horizontal sand column was pre-filled by surfactant solution first. Then air and surfactant solution were co-injected into
<table>
<thead>
<tr>
<th>Surfactant</th>
<th>Chemical Class</th>
<th>Chemical Formula$^a$</th>
<th>MW g/mole</th>
<th>CMC$^b$ mg/L (%)</th>
<th>COD$^c$ g O$_2$/g</th>
</tr>
</thead>
<tbody>
<tr>
<td>Neodol 25-7</td>
<td>Nonionic</td>
<td>CH$_3$(CH$<em>2$)$</em>{11-14}$O(EO)$_2$-H</td>
<td>515</td>
<td>9(0.0009)</td>
<td>1.98 ± 0.02</td>
</tr>
<tr>
<td>Tween 80</td>
<td>Nonionic</td>
<td>C$_{18}$S$<em>6$(EO)$</em>{20}$</td>
<td>1308</td>
<td>33-45 (&lt;0.005)</td>
<td>1.56 ± 0.02</td>
</tr>
<tr>
<td>Aerosol MA80-1</td>
<td>Anionic</td>
<td>[(C$_2$H$_5$)$_2$CHCH$_2$COOCH]$_2$SO$_3$Na</td>
<td>388</td>
<td>7100 (0.71)</td>
<td>1.57 ± 0.05</td>
</tr>
<tr>
<td>AOS 14-16</td>
<td>Anionic</td>
<td>CH$_3$(CH$<em>2$)$</em>{10-12}$CH=CHCH$_2$SO$_3$Na</td>
<td>315</td>
<td>1200 (0.12)</td>
<td>1.66 ± 0.04</td>
</tr>
<tr>
<td>Steol CS-330</td>
<td>Anionic</td>
<td>CH$_3$(CH$<em>2$)$</em>{11}$O(OE)$_2$OSO$_3$Na</td>
<td>422</td>
<td>449 (0.045)</td>
<td>1.65 ± 0.02</td>
</tr>
<tr>
<td>C12-3PO</td>
<td>Anionic</td>
<td>ALFOTERRAL12-3PO-SO$_4$</td>
<td>&lt;400</td>
<td>ND$^d$</td>
<td></td>
</tr>
<tr>
<td>C14-4PO</td>
<td>Anionic</td>
<td>ISOFO14T-4PO-SO$_4$N$^+$</td>
<td>&lt;400</td>
<td>ND$^d$</td>
<td></td>
</tr>
<tr>
<td>C13-4PO</td>
<td>Anionic</td>
<td>CH$_3$[CH$_3$(CH$_2$)$_6$CH(CH$_2$)$_4$-4PO-SO$_4$NH$^+$</td>
<td>&lt;400</td>
<td>ND$^d$</td>
<td></td>
</tr>
</tbody>
</table>

$^a$EO = ethylene oxide, S$_6$ = sorbitan ring. $^b$CMC, critical micelle concentration $^c$COD, chemical oxygen demand, $^d$ND not determined

**Table 4.1 Properties of surfactants**

The column at a ratio of air:surfactant solution=2:1 (fo=0.67). A pressure transducer was connected to the inlet of the sand column and was used to control the pressure drop during the experiments. All the experiments were conducted at constant injection pressure 1 psig. From the flow rate at steady state, the gas apparent viscosity for different surfactants or surfactant mixtures can be calculated, and used to compare the surfactants’ ability to generate foam. Table 4.1 lists the properties of the surfactants which were tested for their foamabilities. Among them, Neodol 25-7 and Tween 80 are nonionic surfactants. The others are anionic surfactants.
4.1.2 Foamability of different surfactants

4.1.2.1 Comparison of Neodol 25-7, Tween 80, Aerosol MA80-1, AOS14-16, CS 230 and CS330

These surfactants were compared using a total concentration of 0.5%(wt) surfactant and 0.5%(wt) NaCl. Figure 4.2 shows the comparison results for these surfactants. According to Figure 4.2, AOS14-16 is a better foamer than CS-330 in the presence of NaCl. However, a separate experiment showed that it will precipitate with only 0.05%
CaCl\(_2\). Thus it will not be considered further because we are planning to inject nutrient solution for the benefit of microorganisms. In the nutrient solution, the concentration of CaCl\(_2\) will be about 0.07\%.

For the rest of these surfactants, Tween 80 and MA80-1 can only generate weak foam under the experimental condition. The gas apparent viscosity for these two surfactants was less than 10 cp. Among CS330, CS230 and Neodol 25-7, the strongest foam was obtained in CS330 case in which the gas apparent viscosity was around 200 cp.

4.1.2.2 Comparison of CS330, C12-3PO, C14-4PO and C13-4PO

According to Daprato [2005] and our SERDP final report (contract DACA72-01-C-0021), a low concentration of CS-330 is needed to avoid hindering the bioremediation process. Because the 0.5\%(wt) surfactant concentration of CS330 is still too high to be benign to the microbial process, we performed more experiments using lower surfactant concentration solutions (0.1\%(wt). Since CS330 has been proved to be the best choice in the former surfactant group, we just picked it out and compared it to several other surfactants. Also, a nutrient solution which contains 0.04\%(wt) Mg\(^{2+}\), 0.069\%(wt) Ca\(^{2+}\), 0.23\%(wt) Na\(^+\) was used to dissolve the surfactant during these tests. This is to simulate a real environment of a remediation application during which the nutrient solution would be injected to promote the biodegradation process.
Figure 4.3 Comparison of surfactant's foam ability (II)

Figure 4.3 shows the experimental results for these surfactants and some of their mixtures. From this figure we can find that when these surfactants were used alone, C13-4PO can generate the strongest foam. The foam generated by C12-3PO or CS330 is weaker than that of C13-4PO. C14-4PO alone has the weakest foamability, the gas apparent viscosity for C14-4PO foam being less than 20 cp. For surfactant mixtures, we found that the mixture of two different surfactants is much stronger than either of them alone. Among them, the mixture of C13-4PO and CS330 (1:1) has the strongest foamability, the gas apparent viscosity being more than 2000 cp. This surfactant mixture is the best foamer among these surfactants we have tested and we chose it for our 3-D experiments.
4.1.3 Effect of different concentration fraction of C13-4PO and CS330

From the former experiments we have found the mixture of C13-4PO and CS330 (1:1) can generate the strongest foam among the tested surfactants under our experimental condition. Some more experiments were performed to investigate the effect of different mixing fraction of these two surfactants on foam strength.

Figure 4.4 shows the results of different mixtures with different fractions of C13-4PO and CS330. In these experiments, gas fractional flow was 100% and the sand in the column had a permeability of about 40 darcy. The experimental results showed that
the surfactant mixture fraction can affect the generated foam strength. When there was only CS330 in the surfactant solution, at steady state the gas apparent viscosity was only about 60 cp. With the increasing of the fraction of C13-4PO in the total surfactant concentration, the steady state gas apparent viscosity also increased. It reached the maximum value when the fraction of C13-4PO in the total surfactant concentration was between 0.4~0.6. When the fraction increased to 0.8 and 1, the gas apparent viscosity decreased from its maximum value. From the plotted curve in Figure 4.4 we can see that the optimum mixture fraction of these two surfactants is between 0.4~0.6. The fraction we chose in our former 1-D experiments (1:1) is in the optimum region.

4.1.4 Other factors affecting foam strength

Some other factors may also affect foam strength in the porous media. Besides the concentration ratio of the surfactants in the surfactant solution, the total surfactant concentration itself also affects the generated foam strength. If the total surfactant concentration is too low, only weak foam can be generated and the gas apparent viscosity will be low. Also, foam is a non-Newtonian fluid because of its deformation properties when pressure or flow velocity is high. So when the gas velocity is higher than some critical value, the gas apparent viscosity will decrease according to the power law of the shear thinning effect. This shear thinning effect is important when modeling and simulating foam flow in porous media. Gas apparent viscosity will be lower
around the injection well due to the higher velocity there. The lower viscosity around 
the injection well will hence benefit the gas injection process. We will have more 
experimental results and discussions in Chapters 6 and 7 regarding the total surfactant 
concentration effect and shear thinning effect on foam strength.

4.2 Lateral Contacting of Aquifer: 2-D sandpack experiments

The purpose of two-dimensional sand-pack experiments was to demonstrate the 
effectiveness of foam in increasing the lateral transport of hydrogen across the aquifer. 
Initial information on foam flow in a vertically layered system was also obtained. 
Comparisons between air foam and hydrogen foam were also made using the results 
from this 2-D sand-pack.

4.2.1 Experimental

Two similarly-constructed flow models were used for the lateral contacting 
experiments. The first is a plastic-cased two-dimensional model that holds a 
20”×3¾”×¾” sandpack (the “plastic sandpack”). The pressure in this plastic sandpack 
is limited to about 6 psig. The second is a steel-cased two-dimensional model that 
holds a 20”×3¾”×¾” sandpack (the “steel sandpack”) which could operate at much 
higher pressures. Both models were obtained as gifts from Shell E&P Company
Dimension 3.8 x 0.8 x 21 inch  Permeability 120 darcy

\[ \Delta P = P_0 - P_1 \]

Figure 4.5 2-D sandpack experiment description

(Houston, TX). The plastic model was constructed of \( \frac{3}{4}'' \)-thick clear plastic. It has three inlet/outlet ports at each end. A perforated plate and a 60-mesh screen were placed at the inside of each end to hold the sand in place and to distribute flow. The model is sealed with a Viton rubber sheet and metal piece at the top. Additionally, the model is clamped to prevent leakage.

The steel model was constructed of stainless steel with a \( 1\frac{1}{4}'' \)-thick glass window in the front of the model that allows visual observations. It was previously used by Szafranski [1997] to demonstrate the effectiveness of the surfactant/foam process for aquifer remediation. Sand is packed in the interior of the model. Similar to the plastic model, the steel model has three inlet/outlet ports at each end. However, a pair of 200- and
60-mesh screens was placed over each port rather than throughout the entirety of each end. At the back of the model, there are fifteen similarly-screened internal pressure ports that can also be used for fluid injection/sampling. The interior space above the sandpack was filled with plaster of Paris enfolded in polyethylene wrap (Saran Wrap) that acted as a non-permeable barrier. A rubber sheet was placed on top of the plaster of Paris and the small air space between the rubber sheet and the top steel cover was pressurized with approximately 70 psig of overburden pressure.

The models were packed following the procedure developed by Szafranski [1997]. Clean silica sand obtained from U.S. Silica (Berkeley Springs, WV) was used for the packing. Most experiments were performed with the models packed homogeneously with coarse F-32 sand. The permeability of this sandpack was determined to be about 120 darcy. Although this is more permeable than typically encountered in an aquifer, the coarse sand was selected to enhance the effect of gravity in the laboratory-scale sandpacks. The porosity obtained with the packing procedure is usually around 40%, which was confirmed from the volume of water displaced during packing.

Some experiments were also performed with the steel model packed heterogeneously with two layers of sand: fine F-95 sand in the lower half and coarse F-32 sand in the upper half of the pack. The permeability contrast was estimated by injecting dyed solution into the heterogeneous sandpack. The ratio of the propagation velocities in
the coarse and fine sands reflects the permeability ratio, and it was determined to be about 13. The upper layer had a permeability of about 130 darcy, and the lower layer about 10 darcy.

Preliminary experiments were performed in both the plastic and steel models. Figure 4.5 shows the layout of the 2-D sandpack experiments. Small 1/16”-ID tubing was used for the flow lines outside the sandpack. Gas, either hydrogen or air, was hand-injected using a syringe while trying to maintain a specified target injection pressure. About 1/3 PV of gas was injected with each syringe, with a little down time between each injection. The injection pressure was measured using a transducer from Validyne (Northridge, CA) that was connected to the inlet port. Gas saturation in the sandpack was calculated at standard pressure from the volumes of gas injected and liquid produced. Trapped gas saturation was measured by injecting liquid (either water when no foam or surfactant when with foam) following the end of gas injection until no more gas was produced in the effluent. The injection pressure during this liquid flush was maintained either near or less than the injection pressure during gas injection.
<table>
<thead>
<tr>
<th>2-D Plastic Sandpack Experiments</th>
<th>Average gas saturation inside the sandpack</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Air injection</td>
</tr>
<tr>
<td>0.8~1.0 psi</td>
<td></td>
</tr>
<tr>
<td>1 PV injected</td>
<td>69%</td>
</tr>
<tr>
<td>Re-inject liquid</td>
<td>54%</td>
</tr>
<tr>
<td>(After Steady State)</td>
<td></td>
</tr>
<tr>
<td>1.8~2.0 psi</td>
<td></td>
</tr>
<tr>
<td>1 PV injected</td>
<td>77%</td>
</tr>
<tr>
<td>Re-inject liquid</td>
<td>64%</td>
</tr>
<tr>
<td>(After Steady State)</td>
<td></td>
</tr>
</tbody>
</table>

Surfactant solution: (0.5% CS-330 0.04%Mg 0.23%Na 0.069%Ca)

**Table 4.2** Comparison of air foam and hydrogen foam on gas saturation

### 4.2.2 2-D Preliminary Experiments

#### 4.2.2.1 Comparison of air foam and hydrogen foam

Hydrogen is explosive when mixed with air. It would be good for us to perform our experiments using air instead of hydrogen to avoid any possible hazards. But hydrogen has a smaller molecule size compared to air, so it is necessary for us to perform some experiments to investigate if there is any difference between air foam and hydrogen foam.

Two series of constant injection pressure experiments were performed in the plastic sandpack. One was around 1 psig, the other about 2 psig. One pore volume (PV) of air
or hydrogen was injected followed by liquid injection at the same injection pressure until steady state was obtained. The gas saturation inside the sandpack was calculated using material balance. The results for hydrogen and air are listed in Table 4.2. From Table 4.2 we can see for both injection pressures, the average gas saturation difference between air foam and hydrogen foam was very small. For example, in the ~2 psig injection pressure case, for air foam, the average gas saturation inside the sandpack was about 77% after 1PV air was injected. For hydrogen foam, this value was about 72%, which is close to 77%. After liquid flush to steady state in the air case, the remaining gas saturation in the sandpack was about 64% compared to about 56% in the hydrogen case.

From these comparisons, we can see there is little difference between air foam and hydrogen foam. A similar conclusion was reached for experiments in vertical sand columns [Daprato, 2005]. So in general, we can use air instead of hydrogen to avoid the danger of explosion but still obtain reliable results at the same time. Most of our following 2-D experiments were performed using air (gas) except as otherwise specified.

4.2.2.2 Effect of foam on lateral transport of gas

Figure 4.6 illustrates the effects of foam on increasing gas sweep and saturation in the sandpack. The experiment was performed under a constant injection pressure of about
(A) Without surfactant, $S_g = 33\%$

(B) With surfactant, $S_g = 73\%$

Hydrogen saturation after approximately 1 PV throughput at $\Delta p \sim 5 psi$

(A) Without surfactant, $S_g = 11\%$

(B) With surfactant, $S_g = 54\%$

Hydrogen saturation after liquid flush that followed H$_2$ injection at $\Delta p \sim 5 psi$

Figure 4.6 Effect of foam on sweep and gas saturation

5 psig. When 1 PV hydrogen was injected, the hydrogen saturation in the foam case was about 73% but in the absence of foam it was only about 33%. The hydrogen saturation in the foam case is thus more than two times greater than without foam. In the foam case, after liquid flush, there still remained about 54% gas in the sandpack, compared to only 11% gas that remained without foam. At this time the contrast in trapped hydrogen saturation after injection of 1 PV is about a factor of 5. Also, without
(A) Without surfactant, $S_g = 32\%$

(B) With surfactant, $S_g = 79\%$

Gas Saturation after approximately 1 PV throughput at $\Delta p \sim 10 \text{ psi}$

(A) Without surfactant, $S_g = 18\%$

(B) With surfactant, $S_g = 63\%$

Figure 4.7 Gas Saturation after liquid flush that followed approximately 1 PV throughput at $\Delta p \sim 10 \text{ psi}$

surfactant, only about 50\% of the sand is contacted by gas while with surfactant compared to about 90\% of the sand with surfactant.

Another experiment was performed using air and a higher injection pressure of 10 psig. Figure 4.7 compares the experimental results without and with surfactant. After 1 PV of gas was injected into the sand pack in the absence of surfactant, gravity override was
quite pronounced and very little of the base of the sandpack was swept by gas. With surfactant, the generated foam swept about 2/3 of the base of the sandpack. The average gas saturation $S_g$ without surfactant was only 32\%, as opposed to 79\% with surfactant. Liquid was injected after 1 PV of gas was injected in both cases. Without surfactant, the liquid flush reduced the gas saturation to $S_g = 18\%$. With surfactant, most of the gas remained immobilized and the average gas saturation was reduced only to $S_g = 63\%$.

The above preliminary experiments illustrated the benefit of in-situ generated foam in improving gas sweep. More of the sandpack was swept by gas and more of the gas remained in the sandpack after liquid flush in the presence of surfactant.

4.2.2.3 Effect of pressure drop across sand pack

Several pairs of experiments were performed for different injection pressures, i.e. 2 psi, 8 psi and 10 psi. All these experiments were stopped after about 1 PV of gas was injected into the sand pack. Higher pressure drops may improve gas sweep both with and without surfactant. The improvement was slight or unnoticeable in the absence of surfactant. From Figures 4.8 and 4.9 it is seen that gas saturation at the end of gas injection in the surfactant-free case was even slightly higher at $\Delta P \sim 2$ psi than at $\Delta P \sim 8$ psi. This higher gas saturation with the lower pressure drop is due
most likely to experimental variations. Nevertheless, gas reached more of the lower parts of the sandpack at the higher pressure drop. Improvement due to the higher pressure was more pronounced in experiments with surfactant (again comparing Figures 4.8 and 4.9). After 1 PV throughput, the average gas saturation was 75% at the higher pressure drop, compared to 60% at the lower pressure drop. Although the higher pressure drop led to only a 15 percentage-point increase in gas saturation, foam generated at the higher pressure drop was much stronger. This is evident from the fact
that most of the foam generated at the higher pressure drop remained immobile during liquid flush. An average gas saturation of 73% remained in the sandpack after flushing for the foam generated at $\Delta P \sim 8$ psi, compared to 36% at $\Delta P \sim 2$ psi. The presence of strong foam in the $\Delta P \sim 8$ psi experiment was also evident from the propagation profiles illustrated in Figure 4.10. Gas traveled in a piston-like displacement front until about 1/3 PV throughput (Figure 4.10.A), indicating very strong, low-mobility foam.
Figure 4.10 Gas Saturation profile of the homogeneous sandpack at $\Delta p \sim 8 \text{ psi}$

The piston-like front remained at $2/3\text{PV}$ throughput (Figure 4.10.B). A gas-overriding front, however, developed ahead of the piston-like front as some of the foam had broken, allowing weaker, more-mobile foam to flow ahead of the strong foam. Nevertheless, the whole sandpack was swept at 1 PV throughput (Figure 4.10.C), indicating a nearly 100% sweep efficiency. The piston-like front observed with $\Delta p \sim 8 \text{ psi}$ indicated the generation of very-strong, low-mobility foam. This behavior was not observed in the experiment with $\Delta p \sim 2 \text{ psi}$.

High pressure drop or high pressure gradient is indeed a necessary condition for the generation of strong foam. Ransohoff and Radke [1988] found the existence of a critical pressure drop for the generation of strong foam. Below this critical pressure drop, only weak foam with relatively high mobility could be generated. Li, Rossen and
Shan et al [2004, 2005] also investigated the critical pressure gradient for strong foam to be generated in homogeneous porous media. Tanzil [2001] confirmed the existence of the critical pressure drop and determined the necessary pressure drop for the generation of strong foam in 1-ft-long one-dimensional sandpacks. We will present more discussion on how to deal with different pressure drop in our laboratory and scale up field simulations in Chapter 7.

4.2.2.4 Experimental results in heterogeneous sandpack

The heterogeneous sandpack configuration presents a greater challenge for gas sweep efficiency. This is especially true with the more permeable layer at the top of the sandpack. Most of the injected gas flows in this thief zone, especially in the absence of foam. Two pairs of experiments were performed in the heterogeneous sandpack, each pair consisting of experiments with and without surfactant. These experiments are preliminary, following the same procedure used for the preliminary experiments in the homogeneous sandpacks. The first pair of experiments in the heterogeneous sandpack was performed with a target injection pressure of 2 psig. The second pair was performed with a higher target injection pressure of 10 psig. Air was used as the injected gas.
Figure 4.11  Gas Saturation after approximately 1PV air injected at $\Delta p \sim 2\,psi$

Even at the lower injection pressure, the benefit of foam was apparent. Figure 4.11 compares the propagation profiles after 1 PV of air was injected with the 2-psig target injection pressure. Without surfactant (Figure 4.11.A), most of the gas flowed along the top of the sandpack in the high-permeability layer. The average gas saturation $S_g$ at 1 PV with no surfactant was only 16%. With surfactant (Figure 4.11.B), more gas entered both layers and $S_g$ was considerably higher, at 43%.

At the higher injection pressure, gas sweep was improved both without and with surfactant. Figure 4.12 displays photographs of the sandpack taken after 1 PV of air was injected at 10-psig target injection pressure. Without surfactant, $S_g$ reached 27%. With surfactant, $S_g$ reached 59%. The benefit of foam was more apparent after about 10 PV of air was injected in both cases (Figure 4.13). Without surfactant, gas flowed mostly in the upper high-permeability region and only about $\frac{1}{4}$ of the low-permeability
layer was swept by gas. In contrast, gas swept the entire sandpack in the surfactant case. Average gas saturation at about 10 PV was $S_g = 48\%$ without surfactant and $S_g = 98\%$ with surfactant.

Figure 4.14 plots the gas saturation history for the 10-psig experiments in the heterogeneous sandpack. The benefit of foam was also very apparent after liquid
Figure 4.14  Gas saturation in the heterogeneous sandpack with air injected at a target injection pressure of 10 psi.

(either water or surfactant solution) was injected following the end of gas injection. Without surfactant, $S_g$ dropped from 48\% to about 20\% as the injected water mobilized most of the gas. With surfactant, however, very small fraction of the gas was mobilized when the surfactant solution was injected and $S_g$ remained above 90\%.

4.3 Conclusions

Surfactant screening experiments were performed using 1-D sand columns. The foamabilities of some surfactants were tested. Among these surfactants, we found that the mixture of C13-4PO and CS330 (1:1) has the strongest foamability in the presence of the nutrient solution. Also, since the surfactant concentration cannot be too high
and inhibit the biodegradation process, we will choose the total concentration of surfactant solution to be 0.1% (wt) for our 3-D experiments.

The effect of different surfactant concentration fractions of C13-4PO and CS330 was investigated. The experimental results show that there exists an optimum mixture range of these two surfactants, which is between 0.4~0.6 (C13-4PO). The strongest foam can be generated when these two surfactants are mixed using a fraction in this range.

Some preliminary 2-D foam experiments were performed. Foam was proved to be able to increase both the gas sweep and the average gas saturation in the sand pack, either homogeneous or heterogeneous. Injection pressure can affect the experimental results. In our 2-D sand pack experiments, higher sweep efficiency and gas saturation can be obtained under higher injection pressure.
Chapter 5

THREE DIMENSIONAL FOAM FLOW

According to some experimental results from Tanzil [2001], foam strength declines as the flow dimension increases, i.e. 1-D foam is stronger than 2-D and 2-D foam is stronger than 3-D. So although we performed some preliminary 2-D experiments which proved the enhancement by foam of gas sweep and trapped gas saturation, it is necessary for us to perform some foam experiments in 3-dimensional experimental equipment to verify the effect of foam. Also, the 3-D foam experiments are indispensable when building a foam simulation model to simulate 3-D foam flow. Literature survey shows no suitable data are available for 3-D foam modeling and simulations.

5.1 3-Dimensional sand tank experiments

5.1.1 3-D tank set up experimental procedures

A 3-D sandpack was designed and constructed for the 3-dimensional foam experiments. The stainless steel frame and the grass walls of the tank were constructed by Aquarium Environments Inc. We designed and constructed the rest of the tank.
Figure 5.1 shows a photograph of the empty tank with wells and sampling tubes. The tank is set on a wood table frame. It has glass walls for its four sides. The thickness of the glass is 0.75 inch. Steel frame is used in the corners and edges to make the tank strong enough to hold the experimental pressure. The actual scale of the tank is 2ft×2ft×2.5ft with a height 2.5ft. But we still call it ‘2x2x2 ft tank’ because the extra 0.5 ft in its height was not packed by sand in our 3-D experiments. The term ‘2x2x2 ft’ here only means the porous media size inside the tank.

There are nine sampling tubes and four injection/production wells in the tank. Figure 5.2 gives sketches of the side/diagonal and top views of the sand tank. The sampling tubes are placed in lines and in each line, they are 0.5 ft from each other. The distance from line to line is also 0.5 ft. These tubes are made by \( \frac{1}{4} \) inch stainless steel tube. In each of these sampling tubes, there are four sample openings. The heights of these
openings are 0, 0.5, 1 and 1.5 ft from the bottom of the tank. Four individual plastic tubes connect these openings to the outside of the tank. During experiments, these sampling tubes can be used to get information such as gas and surfactant solution distribution inside the tank.

The tank has one injection well and three production wells as shown in Figure 5.2. These wells are made by perforated PVC tubes. The diameter of these tubes is 1.75 inch. To keep sand out of these wells, these tubes are wound with 200 mesh stainless steel screen. The injection well is 3.5 inches high, and the three production wells are 2 ft high. All the production wells have their outlets at the bottom of the tank but use a
1/4" inch stainless steel tube to make the flow outlet to be at the same level as the height of the sand pack. This is just to keep the pressure inside the production wells at hydrostatic pressure and simulate an unconfined aquifer. Figure 5.2 also gives a snapshot of the injection well and several sampling tubes.

A 150 mesh screen and a ~200 lbs overburden are put on the top of the sand pack, which is to keep the sand from flowing upwards during gas injection at high pressure. The ~200 lbs overburden can increase the maximum possible injection pressure of the sand pack without fluidizing the sand.

Two different sand packings were used. The sand used was from U.S. Silica. Figure 5.3 shows a drawing of these two packings. One is a homogeneous sand pack using F-42 sand which has a permeability of about 40 darcy. The other is a heterogeneous sand
pack, where two layers of high permeability sand (200 darcy) were packed in the lower part of the tank. Both of these layers are 2.5 inch thick. One is located 2.5 inches and the other 7.5 inches above the bottom of the tank. The rest of the tank is packed with 40 darcy sand. In the heterogeneous pack, injection is into all of the lower, high permeability layer and part of the bottom layer.

Figure 5.4 shows the experimental procedure for the 3-D tank experiments. A pressure transducer was connected to the injection line to measure the injection pressure. A water manometer was installed at the injection line to monitor the air injection pressure. This manometer can hold 2 psig pressure. When injection pressure exceeds 2 psig, water will be blown out to avoid fluidizing the sand in the tank. Two air flow controllers were installed in the injection line. Their flow rate ranges are
0.1~10LPM and 1~100LPM. A three-way valve was installed in the injection line. It can switch between these two controllers during the experiments to get the desired flow rate. Three pressure transducers were installed along the diagonal cross section of the tank at points 0.5 foot from the bottom of the tank. P1, P2 and P3 of Figure 5.4 indicate the locations of these transducers.

Both air/water and foam experiments were performed in the sand tank. The tank was filled with surfactant-free water or surfactant solution before each experiment. As discussed in Chapter 4, the surfactants solution was a 1:1 mixture of 0.05%(wt)CS-330 and 0.05%(wt)C13-4PO. Nutrient salts were also added into the solution, their concentrations being: 0.04%(wt)Mg, 0.23%(wt)Na, 0.069%(wt)Ca. Air was injected into the tank either continuously or intermittently. In most of our experiments, we kept the injection pressure constant by adjusting the air injection flow rate. After each experiment, CO$_2$ was injected into the tank to blow out the remaining gas. Then water was injected. Because of the solubility of CO$_2$ in water, the tank will be filled by water again and ready for the next experiment.

5.1.2 Comparison of air/water and foam experimental results

Experiments were performed in both the homogeneous and heterogeneous sand packs to compare the difference between air/water and foam results.
In air/water injection, because of the low density and viscosity of gas, the injected gas flows mainly upwards and much of the bottom region is left uncontacted. For a heterogeneous system, the uncontacted region may be larger because in such system, the high permeability region will act as a shortcut for the gas flow and then less gas can flow into the low permeability region at the bottom of the tank.

Foam can reduce gas mobility in either homogeneous or heterogeneous system. With the effect of foam, gas apparent viscosity can be greatly increased and the transport of gas along the bottom will be increased. In a homogeneous system, lamella division is the basic foam generation mechanism which happens when a moving lamella train encounters a branch in the flow path. For lamella division to occur, snap-off is important because in the very beginning of foam generation it can provide lamellae which will divide later on. But the mechanism of snap-off is not the main mechanism to generate strong foam in homogeneous system because there is no permeability contrast in it and repeated snap-off is unlikely in such a system [Rossen, 2000]. In a heterogeneous system, both lamella division and snap-off play important roles in determining the strength of generated foam. In a heterogeneous system, when gas flows from a low permeability region to a high permeability region and when there is a permeability contrast of more than 4 [Tanzil, 2002], lamella snap-off will occur because of the difference of the capillary pressure in these two regions. Lamellae generated along the boundary between the low and high permeability sands will block flow paths of gas and hence increase its apparent viscosity in the high permeability regions. More
gas can then flow into the low permeability region. So we expect the effect of foam to be more apparent in a heterogeneous system than in a homogeneous system.

5.1.2.1 Results from homogeneous tank

Figure 5.5 shows the plot of gas injection time vs. gas injection rate in liters per minute (LPM) for the air/water experiment in the homogeneous tank. The air/water experiment was performed at a constant injection pressure ~0.8 psig over hydrostatic pressure. From the plotted curve we can see after about 7 minutes' injection, the gas injection rate reached a steady state. At steady state, the injection rate was about 28 LPM. The total injection time was about 17 minutes and about 6 PV air was injected into the tank in this period. By measuring the produced water volume, we calculated the average gas saturation in the tank at the end of the experiment, which was about 23%.

Figure 5.6 shows the curve of the gas injection rate vs. gas injection time for the foam experiment performed using the same injection pressure as in the air/water experiment. From this plot we can see after about 25 minutes' injection, the injection rate reached a steady state value of approximately 0.8 LPM. The total injection time for 1 PV gas was about 80 minutes. After 1 PV gas was injected, the average gas saturation in the tank was about 66%.
By comparing Figure 5.5 and 5.6, we can find the difference in gas injectivity between air/water case and foam case. The steady state of the injection rate can be reached with fewer PV of gas injected in foam experiment. In foam case, the gas needed to reach
the steady state was about 6 times less than in air/water case (only 0.5 PV needed in foam case but 3 PV gas needed in air/water case). Also in foam case, the injection rate at steady state was much lower than in air/water case. It was about 30 times less than that in the air/water case.

Another big difference between air/water and foam results is the total gas saturation in the tank. In the air/water case, the average gas saturation was only about 23% after 6 PV gas injected. But in the foam case, the average gas saturation was as high as 66% with only about 1 PV gas injected. The average gas saturation in the foam case was about three times higher than in the air/water case with only 1/6 amount of gas injected. The average gas saturation in the foam case was even higher after more PV
gas injected. After 2 PV gas injected in the foam case, the average gas saturation reached about 80%, which was about four times higher than in the air/water case.

From the sample tubes we obtained the gas fractional flow information in the sand tank. Figure 5.7 shows the gas fractional flow contour plots after ~6 PV gas injected for the air/water case. The figures were plotted using Surfer, a contouring and surface mapping software from Golden Software. The dots in these figures represent the sampling ports in the tank. Gas fractional flow plots for the four sampling layers are plotted. Each corresponds to 0.05, 0.5, 1, 1.5 foot from the bottom of the tank. From these plots we can see gas contacted about half of the tank at the bottom layer (0.05 foot from bottom). In the layer 0.5 foot from the bottom, gas contacted about 80% of the tank. For the upper two layers (1 and 1.5 foot from bottom), gas contacted almost all the sample layer. Figure 5.8.A shows the contour plots after 0.37 PV gas injected for the foam case. By that time, gas had contacted about 1/2 of the tank in the lower three sampling layers (0.05, 0.5, 1 foot from the bottom). For the layer 1.5 foot from the bottom, gas contacted only about 1/3 of it. Figure 5.8.B shows the results after about 1PV gas injected. Gas contacted more than about 4/5 area of the tank area in the lower three sampling layers. For the top layer (1.5 feet from the bottom), gas contacted about 2/3 of the area. These results show that more gas was conducted horizontally than vertically in the tank during the foam injection.
From Figures 5.7, 5.8, we can find the big differences between air/water and foam experiments on gas distribution in the tank. With the help of foam, gas contacted much more volume in the tank. Figure 5.9 gives the diagonal cross section gas fraction flow
contour plots for both of these experiments. The difference between air/water and foam is more obvious in these diagonal plots. From the plots we can see that in the air/water case after 6 PV gas injected, there was still quite a lot of the bottom of the tank left uncontacted by gas. In this case, most of the injected gas tended to flow upwards and then out of the top of the tank. In the foam case, after only about 0.37 PV gas injected the area contacted by gas at the bottom of the tank was already almost as large as in the air/water case after 6 PV injected. Gas continued to propagate horizontally along the bottom of the tank with the injection of more gas. After 2 PV gas was injected, almost all the bottom of the tank was contacted by gas.
Figure 5.10  Air/water, heterogeneous sand tank, Injection rate curve
Continuous gas injection, pressure ~0.8 psi, 6 PV gas injected

Figure 5.11  Foam, heterogeneous sand tank, Injection rate curve
Continuous gas injection, pressure ~0.8 psi

5.1.2.2  Results from heterogeneous tank

Figure 5.10 shows the injection rate for the air/water case as a function of time in the heterogeneous sand pack. Gas was injected into the tank at a constant injection
pressure of 0.8 psig over the hydrostatic pressure. From Figure 5.10 we can see that the shape of the curve is similar to the curve of the air/water case in the homogeneous pack. The injection rate increased from the beginning of gas injection and reached a steady state after about 15 minutes' injection. At steady state the injection rate was about \( \sim 30 \) LPM. After about 23 minutes' injection, 6 PV gas was injected into the tank. After 1 PV gas had been injected, the average gas saturation in the tank was about 18%. After 6 PV gas had been injected, the average gas saturation increased to about 39%. Figure 5.11 shows the injection rate for the foam experiment in the heterogeneous tank. More than 1 PV gas was injected into the tank in this case. The injection rate reached its steady state after about 45 minutes' injection. At that time around 0.37 PV gas was injected. At steady state, the injection rate was about 1 LPM which was a little higher than in the homogeneous foam case (\( \sim 0.8 \) LPM). The average gas saturation after 0.37 PV gas injected was 37%, which means gas did not break through to the top of the tank and all the injected gas was trapped in the tank at that time. Compared to the homogeneous foam case, the horizontal transport of gas was increased by heterogeneity and more gas was traveling horizontally. It took a longer time for the injected gas to reach the top of the tank and break through. After 1 PV gas was injected, the average gas saturation in the tank was about 82%, which was 4 times higher than that in the heterogeneous air/water case. From Figure 5.10 and 5.11, we can see the steady state gas injection rate in the foam case is also about 1/30 of the value in the air/water case. As in the homogeneous sand pack, less gas is needed to reach the
steady state gas injection rate when foam is present (∼0.4 PV in the foam case and ∼3 PV in the air/water case). Figure 5.12 (A and B) is the gas fractional flow contour plots for the air/water case in the heterogeneous pack after 1 PV and 6 PV gas injected.
Figure 5.13.A  Foam, Heterogeneous sand tank, gas fraction flow contour plot
Constant injection pressure, ~0.8 psi, ~0.37 PV gas injected

Figure 5.13.B  Foam, Heterogeneous sand tank, gas fraction flow contour plot
Constant injection pressure, ~0.8 psi, ~1 PV gas injected

From the plots we can find that the gas sweep at the bottom of the tank is poor. After
6 PV gas was injected, all the bottom of the tank was still uncontacted by gas. Most of
the injected gas flowed through the high permeability layer and then flowed upwards
out of the tank. It was hard for gas to flow into the low permeability layer at the bottom of the tank. Figure 5.13 (A and B) gives the gas fractional flow contour plots for the heterogeneous foam experiment. We can see that because of the two high permeability layers in the lower part of the tank, gas sweep efficiency was greatly increased, especially near the bottom of the tank. After only 0.37 PV gas was injected, more than 90% percent of the bottom of the tank was already contacted by gas. Also, gas contacted almost all the layer of 0.5 foot from the bottom. After 1 PV gas injected, all the bottom layer was contacted by gas (the gas fractional flow was 100% from all 9 sampling points in the bottom). Gas also contacted almost all of the area of the other three upper layers.
Figure 5.14 shows a comparison of the gas fractional flow contour plots along the diagonal cross section in the heterogeneous tank. The difference between air/water and foam is more apparent in these plots. In the air/water case, the gas flow direction was mainly upwards and the shape of the flow area resembled a cone. But in the foam case, gas flow was very different with a much stronger lateral component. In the air/water case, after 1 PV gas was injected, average gas saturation was only 18% and most of the lower part of the tank was uncontacted by gas. After even 6 PV gas injected, most of the lower part of the tank was still not contacted by gas and average gas saturation was still low (about 39%). On the contrary, in the foam case, after 1 PV gas was injected, average gas saturation was as high as 82% and most of the lower part of the tank was contacted by gas. After 2 PV gas was injected, almost all the tank was contacted by gas and the average gas saturation increased to about 90%. From these comparisons we can see that in the heterogeneous system, foam greatly increased the gas sweep efficiency and the average gas saturation. Without foam, it is very difficult to sweep the whole tank, especially in the low permeability regions.

Figure 5.15 (A and B) shows the pressure profile along the diagonal cross section of the tank 6 inch from the bottom. From the plots we can see that in air/water case, most of the pressure drop was around the injection well. P1 was the highest pressure drop among the three measured pressure drops. P2 and P3 were negligible compared to P1. In foam case, P1 was not the highest pressure drop. Instead, P2 was higher than P1 and P3. The pressure profiles demonstrated that in air/water case, there was little flow
Figure 5.15.A  Air/Water; Heterogeneous pack, Constant injection pressure ≈ 0.8 psi
Pressure profiles along the diagonal cross section of the tank

Figure 5.15.B  Foam; Heterogeneous pack, Constant injection pressure ≈ 0.8 psi
Pressure profiles along the diagonal cross section of the tank

except near the injection well. In foam case, gas flowed throughout the cross section of
the tank. The fact that P1 was lower than P2 also told us that foam had lower strength around the near well region than in the farther region. We observed this phenomenon not only in this heterogeneous foam experiment, but also in all the other 3-D foam experiments. Shear thinning effect of foam under high injection rate may be the reason for this phenomenon. In Chapter 6, we will have more discussion on building a model and simulating the 3-D foam flow. The proposed simulation model successfully history matched the pressure profile by taking into account of the shear thinning effect of foam.

5.1.2.3 Summary

From all these comparisons, we found that foam can greatly increase the lateral gas distribution and average gas saturation in both the homogeneous and the heterogeneous 3-D sand tanks. These increases can benefit the hydrogen biosparging processes. Also, at steady state, foam will result in a lower injection rate compared to the air/water case. The ratio between foam and air/water was about 1/30 in both the homogeneous and the heterogeneous packs.

Though foam can reduce gas mobility in both of the homogeneous and heterogeneous pack, the effect of foam is more apparent in the heterogeneous pack than in the homogeneous pack. The average gas saturation was higher in the heterogeneous pack than in the homogeneous pack. After 1 PV gas was injected, the average gas saturation
in the heterogeneous tank was about 82%. Compared to the 66% gas saturation in the homogeneous tank after 1 PV gas was injected, the gas saturation in the heterogeneous sand pack increased by 16% because of the effect of heterogeneity. The gas contacted area in the heterogeneous pack was also larger than in the homogeneous pack. By comparing Figures 5.8 and 5.13 we can easily see that the gas sweep in the lower part of the sand tank was larger in the heterogeneous case.

5.1.3 Comparison of different injection strategies

Two other kinds of foam experiments were performed in both the homogeneous and the heterogeneous 3-D tank to test the effect of different injection strategies. One was performed using an intermittent gas injection method: gas was injected into the tank in
a 5 minutes on and 5 minutes off cycle. The other one was performed using a lower injection pressure at about 0.4 psi, which was about a half of the constant injection pressure (0.8 psi) chosen in our former foam experiment.

5.1.3.1 Results from homogeneous tank

Figure 5.16 shows the behavior of the injection rate for the intermittent injection foam experiment in the homogeneous tank. The rate was about 3.5 LPM at the beginning of gas injection. As injection time went on, it declined and reached its steady state after about 100 minutes operation time. Because it was an intermittent injection, the actual gas injection time was about 50 minutes. At steady state, the injection rate while flowing was about 0.5 LPM, which was lower than the ~0.8 LPM in the continuous gas injection foam experiment.

Figure 5.17.A and B show the gas fractional flow contour plots after 0.37 PV and 1 PV gas were injected in this intermittent injection experiment. After 0.37 PV gas was injected, around 80% of the bottom layer was already contacted by gas. Almost no gas had flowed out of the tank at this time as the average gas saturation in the tank was about 35%. After 1 PV gas was injected, almost all the bottom of the tank was contacted by gas. Gas also contacted more than 90% area of the upper part of the tank. At that time, average gas saturation was about 73%, which was significantly higher than the 66% found in the continuous air injection foam case.
Figure 5.17.A  Foam, Homogeneous sand tank, gas fraction flow contour plot
Intermittent gas injection, ~0.8 psi, ~0.37 PV gas injected

Figure 5.17.B  Foam, Homogeneous sand tank, gas fraction flow contour plot
Intermittent gas injection, ~0.8 psi, ~1 PV gas injected

Figure 5.18(A and B) shows the gas fractional flow contour plots for a constant injection rate (~0.4 LPM) foam experiment. Though it was a constant injection rate experiment, in this experiment, the injection pressure reached steady state very quickly
Figure 5.18.A Foam, Homogeneous sand tank, gas fraction flow contour plot
Constant rate gas injection, ~0.39 LPM, ~0.37 PV gas injected

Figure 5.18.B Foam, Homogeneous sand tank, gas fraction flow contour plot
Constant rate gas injection, ~0.39 LPM, ~1 PV gas injected

and stayed at about 0.4 psi, in contrast to the 0.8 psi of the other experiments. So, it was also a low injection pressure (0.4 psi) foam experiment. From Figure 5.18 we can see that this constant injection rate (low injection pressure) experiment does not have a
good gas sweep. After 0.37 PV gas was injected, in the bottom of the tank, only a small area around the injection well was contacted by gas. After 1 PV gas injected, there was still about 80% of the bottom not contacted by gas. For the upper layers, gas sweep was also not good. Gas can not propagate far horizontally and most of the injected gas flowed out from the top of the tank. One can also tell this from the gas saturation in the tank, which after 1 PV gas injected was only 37%, much less than that in the other foam experiments.

By comparing Figures 5.8, 5.17 and 5.18, we can find we obtained the best gas distribution and the highest gas saturation in the intermittent gas injection experiment. Let us take the bottom layer as an example for comparison. In the constant injection pressure of 0.8 psi, continuous air injection case, gas contacted about 1/2 of the tank in the bottom layer after 0.37PV gas was injected and about 4/5 of the bottom layer after 1PV gas was injected. In the constant injection pressure of 0.8 psi, intermittent air injection case, gas contacted about 3/4 of the tank in the bottom layer after 0.37PV gas was injected and almost all of the bottom layer after 1PV gas was injected. In the constant gas injection rate (~0.4 psi max) case, gas contacted about 1/16 of the tank in the bottom layer after 0.37PV gas was injected but only about 1/5 of the bottom layer after 1PV gas was injected.

We can see that the intermittent injection method can increase the lateral transport of the gas in the tank. The shut-in intervals during the experiment allow the sands to be
Figure 5.19  Foam, heterogeneous sand tank, Injection rate curve
Intermittent gas injection, pressure ~0.8 psi

partially re-saturated, and this can keep the foam from drying and thus breaking. The worst case in gas distribution was the constant injection rate (lower injection pressure) case. In this case the injection pressure was only about 0.4 psi above hydrostatic pressure, about half of the pressure in the other foam experiments. Because of the lower injection pressure, the pressure gradient was lower and there was no strong foam generated. So the gas flow was dominated by gravity, and most of the gas flowed upwards and did not contact much of the bottom of the tank. To obtain best results, it is important to inject gas using a high enough injection pressure. With regard to average gas saturation in the tank, gas contacted more volume and foam was stronger in the intermittent air injection case. We obtained higher average gas saturation in this case as well.
5.1.3.2  Results from heterogeneous tank

Figure 5.19 shows the behavior of the injection rate in the heterogeneous tank. It used the same injection pressure as in the continuous gas injection experiment: 0.8 psi over hydrostatic pressure. As in the homogeneous intermittent foam experiment, gas was also injected into the tank using a 5 minutes on and 5 minutes off strategy.

After about 1 hour’s intermittent injection (30 minutes actual injection time), the injection rate reached a steady state. At steady state, the injection rate while flowing was about 0.6 LPM, which is lower than the steady state injection rate (~1 LPM) in the continuous injection case. The lower rate indicates that stronger foam was generated in the tank than in the continuous injection case. The explanation for this phenomenon is the same as for the homogeneous packing, i.e., water saturation increases in the foam regions when gas is not being injected. As a result, the foam does not become too dry, which would cause lamellae to break. In this intermittent experiment, after about 0.37 PV gas was injected, average gas saturation inside the tank was about 37%. Gas did not break through at that moment. After 1 PV gas was injected, average gas saturation in the tank reached about 85%, which was about 3% higher than in the continuous gas injection foam case.

Figure 5.20 (A and B) shows the gas fractional flow contour plots for this intermittent injection foam experiment. By comparing with Figure 5.13 (A and B), we find that the
Figure 5.20.A  Foam, Heterogeneous sand tank, gas fraction flow contour plot
Intermittent gas injection, ~0.8 psi, ~0.37 PV gas injected

Figure 5.20.B  Foam, Heterogeneous sand tank, gas fraction flow contour plot
Intermittent gas injection, ~0.8 psi, ~1 PV gas injected

gas sweep results of the intermittent injection case were very similar to those of the continuous injection case. Both had good gas sweep efficiency in the lower part of the tank. But strictly speaking, the intermittent injection case had a better sweep efficiency
than the continuous case, though the difference between them is slight. For example, after 1 PV gas was injected, in the intermittent case, the layer 0.5 ft from the bottom was completely contacted by gas. But in the continuous injection case, there were still some areas where the gas fractional flow was less than 100%.

Figure 5.21 gives the behavior of the gas injection rate for the lower injection pressure foam experiment. This experiment was performed using 0.4 psi over hydrostatic pressure, which is half of the injection pressure we used in our former heterogeneous foam experiment. The injection rate reached a steady value of about 0.5 LPM after about 45 minutes injection which was about half of the steady state rate with 0.8 psi injection pressure. It took about 150 minutes to inject 1 PV gas into the tank. After 1
PV gas was injected, the gas saturation in the tank was only about 60%, which was 22% lower than in the 0.8 psi foam experiment. Figure 5.22 (A and B) shows the gas
fractional flow contour plots when 0.37 and 1 PV gas was injected into the tank. From these plots we can see that though the gas contacted area was relatively large in this 0.4 psi foam experiment, the gas sweep efficiency was obviously worse than in the 0.8 psi foam experiment (Figure 5.13 A and B). After 0.37 PV gas was injected in the 0.4 psi foam experiment case, only about 75% area of the bottom was contacted by gas. But in the 0.8 psi foam experiment case, more than 90% was contacted by gas. After 1 PV gas was injected, in the 0.4 psi case, there was still quite a lot area in the lower two layers which had not been contacted by gas. In the 0.8 psi case, almost all of the lower part of the tank was contacted by gas. This can be easily identified from the shade of the contour plots. In the 0.4 psi case, there is a large dark area in the bottom, which means low gas fractional flow there. But in the 0.8 psi case, almost all the bottom of the tank is white, which means a very high value of gas fractional flow.

5.1.3.3 Summary

Shi and Rossen [1998] argued that injection well pressure is the key to avoid gravity segregation of gas. Our 3-D experimental results also prove that the injection pressure is very important to obtain a good gas sweep and high gas saturation. In both the homogeneous and the heterogeneous sand packs, the injection pressure should be high enough to generate strong foam, which promotes the horizontal flow.
Also, for a constant injection pressure experiment, the intermittent injection method provides better gas sweep efficiency and higher average gas saturation than the continuous injection method. In the heterogeneous pack, the effect of intermittent injection is not as great as in the homogeneous pack. Nevertheless, the intermittent injection method still benefits gas sweep efficiency and average gas saturation in the tank, either in the homogeneous pack or the heterogeneous pack.

5.1.4 Foam stability

In the biodegradation process, hydrogen acts as an electron donor and halogenated compounds such as chlorinated solvents act as electron acceptors that are reduced in the reductive dechlorination process. So foam stability is another important consideration in the hydrogen biosparging process. If foam is stable, hydrogen can be trapped in the aquifer for a longer time, which benefits the biodegradation process. A foam stability experiment was performed after a 0.8 psi continuous gas injection foam experiment in the heterogeneous sand pack. After 1 PV gas was injected into the tank, gas injection was stopped and a water table was added on the top of the sand pack. By measuring the change of the water level on the top of the sand and performing a material balance, we can calculate the gas saturation inside the tank. Figure 5.23 shows the change of the average gas saturation with time. From this plot we can see that the generated foam is quite stable. After about 20 days, gas saturation in the tank only changed about 5 percent, dropping from about 85% to 80%.
Figure 5.23  Foam, heterogeneous sand tank, constant injection pressure ~0.8 psi After 1 PV gas injected, the change of average gas saturation in the tank

5.2    Rice ECRS Tank Experiments

Besides the 3-D tank laboratory experiments, we performed 3-D foam experiments on a larger scale in the Rice ECRS tank. The scale of this tank is intermediate between the laboratory bench-scale and full-scale field implementation. By doing these experiments, we can obtain more information on how foam affects the gas flow on a larger scale, i.e. a field application.

5.2.1    Experimental

Figure 5.24 shows the layout of the Rice ECRS tank. It is a 756 cubic feet rectangular container with dimensions 18 feet long, 7 feet wide and 6 feet deep. It was constructed
by Galbreath Inc (Model OS1872). The tank is filled with 20 darcy sand. At each end of the tank, there is a pea gravel layer which is about 1 foot thick and 4 feet high. The permeability of the pea gravel layer is much higher than 20 darcy. There are two sampling layers in the tank, one 6 inches from the bottom of the tank and the other about 2 feet from the bottom. As shown in Figure 5.24, the red dots and some of the blue dots are the sampling points of the 6-inch layer. The green dots and the rest of the blue dots are the sampling points in the 2-foot layer. During the experiments, samples can be obtained through these tubes, and information such as gas or surfactant distribution can be obtained. The surfactant solution we chose was the same as in our 3-D tank experiment, a ratio of 1:1 mixture of 0.05% (wt) CS-330 and 0.05% (wt) C13-4PO.
Before an experiment, the ECRS tank was filled with water or surfactant solution. Then gas was injected into the tank from the injection ports, which were located six inches from the bottom of the tank. In the foam experiments, we did not fill the whole tank with surfactant solution. Instead, we injected 1/3 PV water into the tank first and then injected 2/3 PV surfactant solution to fill the tank. This was because we were short of surfactant solution and could not fill the whole tank with it. In the later part of this thesis (Chapter 7), we will prove that the 2/3 PV surfactant is enough to generate strong foam and obtain similar results as in a tank completely filled with surfactant solution.

During all these experiments, we kept the injection pressure at 5 psig over hydrostatic pressure, which was the maximum feasible pressure considering the condition of the tank. There was no screen or overburden on the top of the tank. If the injection pressure was higher than 5 psig, the sand in the tank would be fluidized and then no useful results could be obtained. In these experiments, gas was injected either continuously or intermittently. For intermittent injection experiments, gas was injected intermittently with a time interval of 5 minutes.

5.2.2 Experimental Results

Figure 5.25 shows the gas distribution expressed as contours of gas fractional flow for the air injection case. About 0.63 PV gas was injected into the tank from the injection
Figure 5.25  Gas distribution for the gas injection case, injection pressure 5 psig, 0.63 PV gas injected, average injection rate 1 ft\(^3\)/min

port. Air was observed to channel and bubble from several locations where a pile of fluidized sand was brought to the surface. The average injection rate was about 1 ft\(^3\)/min. In this air injection experiment, the water level change at the top of the tank was not measurable, which indicated that only a small amount of the injected air was trapped in the tank.

After the air injection experiment, we refilled the tank with water and then injected the surfactant solution. Figure 5.26 shows the surfactant distribution in the tank before the foam experiment as determined by analyzing samples taken from the various sampling points. Surfactant solution was injected from the middle injection port of the tank, which is the blue dot in Figure 5.26. The injection port was 6 inches above the bottom. From the plots we can see that we obtained the maximum surfactant concentration around the injection port. After injection of the surfactant solution, we injected gas into
the tank using the same injection port as in the air/water experiment and in the surfactant solution injection process. The injection pressure was kept at 5 psig. Figure 5.27 shows the gas distribution in the tank for the foam experiment after 0.075 PV gas injected. The average injection rate we obtained was about 0.22 ft³/min, about 1/5 that
in the air/water case. From these contour plots we can see, after only 0.075 PV gas injected, the gas distribution profile was already similar to the gas distribution in the air/water case. But in the air/water case, 0.63 PV gas was injected, which was about 9 times more than in the foam case.

After injecting 0.075 PV gas into the tank from the middle injection point, we changed our injection point to another location, which was at the same level of the original injection point but was on the left side of it. One reason for this injection location change was because we suspected that during the air/water experiment some channels and holes might have formed just above the middle injection port. Then in the later foam experiment foam would tend to flow into these channels and holes and so would not spread much laterally. If this were the case, we would not obtain the real effect of foam flow on gas distribution in a well packed homogeneous porous medium.

Considering this, we changed the location of our injection port and injected gas from the new port on two separate days. Figure 5.28.A shows the gas distribution profile after the first day's experiment. About 0.03 PV gas was injected into the tank during the day with an average injection rate of about 0.04 ft³/min. Most of the injected gas, around 84%, was trapped in the tank. Only a few bubbles broke through to the top of the tank. From Figure 5.28.A we can also see that most of the injected gas flowed along the bottom of the tank. The layer 6 inches from the bottom layer has a higher gas saturation than the layer 2 ft from the bottom.
Figure 5.28.A  First day, Foam, left injection port, 5 psig, 0.03PV gas injected, Average injection rate 0.04 ft$^3$/min, Percent of trapped gas 84%

Figure 5.28.B  Second day, Foam, left injection port, 5 psig, 0.05PV more gas injected, Average injection rate 0.09 ft$^3$/min, Percent of trapped gas 50%

After the first day’s experiment, gas injection was shut off, the tank was left overnight and gas injection was continued in the second day. Figure 5.28.B shows the gas distribution profile after the second day. In this injection period, we injected about 0.051PV gas into the tank at an average injection rate of about 0.09 ft$^3$/min. About
Figure 5.29  Remaining gas distribution in the tank, after vibration

Figure 5.30  Gas distribution after gas reinjection from the middle injection point, Foam, 5 psig, 0.025PV gas injected, Average injection rate 0.08 ft³/min, Percent of trapped gas 60%

50% of the injected gas was trapped. From Figure 5.28.B we can see that the gas-contacted area increased and was larger than in the first day’s experiment. Around the injection point, almost all the layer 6 inches from the bottom was contacted by gas. Though the gas-contacted area in the layer 2 ft from the bottom also increased, it was
less than in the lower layer. This indicates that with foam, the horizontal transport of
gas in the porous medium was greatly increased. Compared to air/water injection,
more of the injected gas can flow along the horizontal direction and hence increase the
gas sweep in the bottom of the tank. The time of gas breakthrough was also delayed by
the presence of foam and the trapped gas in the tank was increased.

After finishing the left injection point experiments, we used a vibrator to vibrate the
sand in the middle part of the tank in an attempt to remove the possible holes and
channels above the middle injection port. Then we re-injected foam from the middle
injection port. During the vibration, most of the trapped gas escaped from the tank,
but some gas still remained. Figure 5.29 shows the remaining gas distribution after we
vibrated the tank. Figure 5.30 shows the gas distribution after we re-injected surfactant
solution and then gas from the middle injection port. About 0.025 PV gas was injected.
The average injection rate was about 0.08 ft³/min. Compared to the first foam
experiment using this injection port, the injection rate decreased from 0.22 ft³/min to
0.08 ft³/min. This decrease in injection rate confirmed that there were some channels
or holes above the middle injection point when we first injected foam. These channels
and holes were removed by the vibration. In the re-injection experiment, about 60% percent of the injected gas was trapped in the tank. We can also find from these plots
that gas contacted more area in the bottom layer than in the layer 2 ft from the bottom.
Moreover, the area of the sand contacted at both levels was significantly greater after
vibration (Figure 5.30) than before vibration (Figure 5.27).
These ECRS tank experiments proved that in a quasi-field scale, foam affects the flow of gas and increases the lateral gas distribution along the bottom. It also increases the total gas saturation. In a porous medium which has channels or big holes, foam effects will be weakened because gas will tend to flow into these regions, bypassing nearby regions. Also, we found that in the ECRS tank, when foam was present and the porous medium was tightly packed, the injection rate was about 1/25 compared to the air/water injection rate. In our 3-D tank experiments, this ratio was about 1/30. The difference of these two ratios was caused most likely by experimental variations. In general, in the 3-D foam flow under our experimental conditions, either in the 3-D sand tank or in the larger ECRS tank, the air/water injection rate vs. foam injection rate was around 1/30.

5.3 Conclusions

3-D foam experiments were performed to validate the effects of foam on the enhancement of gas/hydrogen sparging. Some were performed in a 2x2x2 foot tank, others in an 18x7x6 ft tank. The following conclusions can be drawn from the experimental results:

1. In both the larger and the smaller tank, foam greatly increased the lateral transport of gas and increased gas sweep efficiency. A heterogeneous packing was tested in the 2x2x2 foot tank and it proved that when heterogeneity consisted of high-permeability layers, the gas sweep efficiency was better than in homogeneous case.
2. Foam can greatly increase the gas saturation in the tank.

3. The best injection strategy for a foam experiment, either in homogeneous pack or heterogeneous pack, is intermittent injection at constant injection pressure. Higher gas saturation and better gas sweep can be obtained by using this injection method.

4. If the porous medium is not packed tightly, i.e. some channels and holes exist inside it, the effect of foam will not be as good as in a tightly packed porous medium. Gas will flow into the channels and holes, bypassing tightly packed regions and breaking through quickly.

5. In both the laboratory 3-D tank and the Rice ECRS tank experiments, the injection rate ratio between the air/water case and foam cases was about 30:1 for the same injection pressure.

6. The generated foam is stable. Remaining gas saturation in the tank is high and remains almost the same 20 days after stopping gas flow.
Chapter 6

FOAM MODELING AND SIMULATION-----FROM 1-D TO 3-D

Besides the experimental validation of the effects of foam in porous media, we need to build a model to simulate foam flow. By having a foam simulation model, we can use a simulator to simulate and predict 3-D foam behavior. It will save time and labor because it takes too much time and effort to perform a single 3-D tank experiment and it is not feasible to conduct experiments for porous media having all dimensions of interest. The reservoir simulator UTCHEM was modified for foam flow. The foam parameters were measured in 1-D sand columns and the simulator was modified to match the 1-D and 3-D experiments.

6.1 UTCHEM

UTCHEM is a multiphase, multicomponent, three-dimensional chemical compositional finite-difference simulator. This simulator was developed following the concept of Pope and Nelson [1978] to simulate 1-D surfactant-enhanced oil recovery processes. It was then extended to include other chemical processes and a variety of geochemical reactions between the aqueous and solid phases. In this simulator, the flow and mass-transport equations are solved for any number of user-specified
chemical components and these components can form up to four fluid phases (gas, water, oil, and microemulsion) [Delshad et al 1996].

In UTCHEM, the balance equations are as follows: mass conservation equations, an overall balance equation that determines the pressure for up to four fluid phases, and an energy balance equation to determine the temperature. The flow equations allow for chemical reactions and phase behavior and are complemented by constitutive relations.

In the mass conservation equation, the assumptions imposed when developing the flow equations are local thermodynamic equilibrium except for tracers and dissolution of organic components, immobile solid phases, slightly compressible soil and fluids, Fickian dispersion, ideal mixing, and Darcy’s law. The energy balance equation is derived by assuming that energy is a function of temperature only and energy flux in the aquifer or reservoir occurs by advection and heat conduction only. The aqueous pressure equation is developed by summing the mass balance equations over all volume-occupying components. Darcy’s law is substituted for the phase flux terms, using the definition of capillary pressure to relate pressures in the various phases.

The resulting flow equations are solved using a block-centered finite-difference scheme. The solution method for these equations is implicit in pressure and explicit in concentration (IMPES type). One- and two-point upstream and third-order spatial
discretizations are available as options in the code. A scheme that is approximately third-order in space is used to minimize numerical dispersion and grid-orientation effects. The third-order method gives the most accurate solution.

The model includes options for multiple wells completed either horizontally or vertically. The boundary conditions are no-flow and no-dispersive flux across the impermeable boundaries, unless the option of open lateral boundaries is specified. Heterogeneity and variation in relative permeability and capillary pressure are allowed throughout the porous medium, since for example, each gridblock can have a different permeability and porosity.

The phases consist of a single component gas phase and up to three liquid phases: aqueous, oleic, and microemulsion, depending on the relative amounts of the various components and effective electrolyte concentration (salinity) of the phase environment. The number of components is variable depending on the application, but would include at least surfactant, oil and water for SEAR modeling. When gas, electrolytes, tracers, co-solvents, polymer, and other commonly needed components are included, the number of components may be on the order of twenty or more. The tracers can partition, adsorb, and decay if they are radioactive. UTCHEM can model partitioning interwell tracer tests (PITTs) for the detection and estimation of contaminants and for remediation performance assessment in both saturated and vadose zones [Jin et al, 1995].
Surfactant phase behavior modeling is based in part on the Hand representation of the ternary phase diagram [Hand, 1939]. A pseudophase theory [Prouvost et al., 1984; Prouvost et al., 1985] reduces the water, oil, surfactant, and co-surfactant fluid mixtures to a pseudoternary composition space. The major physical phenomena modeled are density, viscosity, velocity-dependent dispersion, molecular diffusion, adsorption, interfacial tension, relative permeability, capillary pressure, capillary trapping, cation exchange, and polymer and gel properties such as permeability reduction, inaccessible pore volume, and non-Newtonian rheology. The phase mobilization is modeled through entrapped phase saturation and relative permeability dependence on trapping number.

Non-equilibrium mass transfer of an organic component from the oleic phase to the surfactant-rich microemulsion phase is modeled using a linear mass transfer model similar to that given by Powers et al. [1991]. Non-equilibrium mass transfer of tracer components is modeled by a generalized Coats-Smith model [Smith et al., 1988]. The model includes options for multiple wells completed either horizontally or vertically. Aquifer boundaries are modeled as constant-potential surfaces or as closed surfaces.

6.2 Foam Modeling Methods in Porous Media

There are many ways to model foam flow in porous media. Most of the models modify gas mobility when foam is generated. These foam models can be classified into
four major groups. They are empirical and semi-empirical models, population balance models, fractional-flow theory models and percolation (statistical networks) models.

As mentioned earlier, foam has no direct impact on water mobility. Gas mobility is reduced significantly when foam is present; the stronger the foam, the lower the gas mobility. Foam texture (lamella density) determines the strength of foam and itself depends on many factors such as pore structure, heterogeneity, surfactant formulation, capillary pressure, flow rates, presence of non-wetting phase, etc. It is very difficult and complex to investigate the relation between foam mobility and these factors. Many investigators tried to present foam mobility as an empirical function of some key factors such as velocity, permeability, surfactant concentration and gas saturation, etc., using various correlations. An example of the empirical modeling is the STARS foam model developed by the Computer Modeling Group in Calgary, Canada.

Another more-comprehensive approach which fully describes foam mechanisms is the "population balance" method. Several investigators [Falls et al., 1988; Kovscek et al., 1994] have used this approach in modeling foam in porous media. The significant achievement of the method is accounting for non-Newtonian gas mobility with respect to bubble population dynamics. In this approach, foam texture is explicitly taken into account. They solve a number of equations to describe lamella generation and destruction processes. The effective foam viscosity is determined by the calculated lamella density. The population balance approach has been used to successfully model
a number of homogenous core experiments [e.g. Fergui et al., 1998]. The shortcoming of this model is its complexity. Many parameters need to be determined in this approach. In the model of Kovscek et al.[1994], ten parameters need to be determined by performing corresponding experiments.

Attempts were performed to simplify the population-balance model by some investigators. Hatzivramidis et al. [1995] proposed a simplified population-balance model. They did not include the population balance equation, the key equation that describes foam texture, in their model. When the foam is weak, only the relative permeability of the gas was modified. In the case of strong foam, the viscosity of the gas was also modified. Their model was incorporated into a thermal simulator, THERMS. Bertin et al. [1998] offered a simplified model of the full population balance model of Kovscek et al. [1994]. Foam texture was calculated using a bubble-population correlation. It was represented as a function of porosity, permeability, gas saturation, the limiting capillary pressure and the flowing foam fraction. The effective gas viscosity was modified when foam was present. This model was shown to give satisfactory results in modeling transient core experiments. However, it does not produce the steady-state independence of pressure drop on liquid rates at high foam qualities and on gas rates at low foam qualities as observed by Osterloh and Jante [1992].
Zhou and Rossen [1992] first used the fractional flow theory to model foam. The heart of fractional-flow models for foams is the time-distance diagram. They developed the fixed-$P_c^*$ model following the idea of Khatib et al [1988]. The model assumes that foam changes from strong foam to weak foam in a narrow range of a limiting capillary pressure, $P_c^*$. No foam will exist above $P_c^*$ and when capillary pressure is below $P_c^*$, a constant mobility reduction factor for strong foam will be used. Their model can represent the high-quality steady-state foam behavior very well and can also approximate foam behavior in the low-quality regime. Incorporating the concept of limiting capillary pressure into the framework of the fractional-flow solution greatly simplifies the modeling task without loss of generality. If the steady-state foam quality and Sw* are known, the model will offer a simple solution for gas mobility without calculating the complex population-balance equations.

Rossen and Gauglitz [1990] presented a percolation approach to foam modeling that describes the generation and displacement of foam in a porous medium. Kharabaf and Yortsos [1998] modified the percolation approach using a pore network model to simulate continuous and discontinuous gas regimes given a snap-off probability. Only snap-off and leave-behind were considered as foam generation mechanisms. Although these approaches provide good qualitative predictions, they may require intensive computations. Moreover, foam generation mechanisms depend on many factors. These models only assume a specific mechanism while trying to predict effects
resulting from a wide range of these factors. They cannot be applied directly using available reservoir simulators.

6.3 A Population Correlation Foam Model

As we mentioned in Chapter 2, foam in porous media is defined as a dispersion of gas in a liquid such that the liquid phase is continuous, and at least some part of the gas is made discontinuous by thin liquid films called lamellae.

The transport of foam in porous media is governed by Darcy’s Law:

\[ u_g = \frac{k k^f_{rg}}{\mu^f_g} \nabla p \]  

(6-1)

Flowing foams occur when snap-off or lamella division produces discrete bubbles. When foam is present, both the gas relative permeability \( k^f_{rg} \) and the gas apparent viscosity \( \mu^f_g \) are affected. Its relative permeability will be smaller than in conventional two-phase flow and its viscosity larger because of the resistance to movement of lamellae. The reduction of gas relative permeability arises because only a fraction of the gas phase is actually flowing when foam is present, i.e., some gas is trapped. The increase of apparent gas viscosity comes from the flow of foam bubbles. Resistance to
flow of the bubbles is greater than resistance to flow of gas when no lamellae are present.

6.3.1 Change of $k_{rg}^f$

In the model, the relative permeabilities $k_{rl}$ for liquid and gas phases are calculated using the Corey model as follows:

$$k_{rl} = k_{rl}^0 \left( \frac{S_l - S_{rl}}{1 - S_{rl}} \right)^{e_l}$$  \hspace{1cm} (6-2)

Where $k_{rl}^0$, $S_l$, $S_{rl}$, $e_l$ are the relative permeability endpoint, saturation, residual saturation and exponent of phase $l$. As we mentioned in Chapter 2, the liquid relative permeability is the same function of liquid saturation either with or without foam. Gas relative permeability, $k_{rg}^f$, is changed, however, as discussed above.

Some investigators, e.g., Falls et al [1989], suggested that the effective foam permeability $k_{rg}^f$ is reduced proportionally to the flowing gas fraction $x_f$:

$$k_{rg}^f (S_g) = x_f k_{rg} (S_g)$$  \hspace{1cm} (6-3)
However, the fraction of gas that is flowing is a complex function of velocity, saturation, and capillary pressure. It is not easy to determine this function by simple experiments. Since the reason for the changing of gas relative permeability is the increased gas trapping inside the porous medium, we propose a simpler way to account for this: we simply increase the gas residual saturation when calculating the gas relative permeability:

\[ k_{rg}^f = k_{rg}^0 \left( \frac{S_g - S_{rg}^f}{1 - S_{rg}^f} \right)^{e_i} \]  

(6-4)

When foam is weak, which means the flowing gas fraction is high, the value of \( S_{rg}^f \) should be lower compared to the value of \( S_{rg}^f \) in strong foam. The value of \( S_{rg}^f \) can be determined by doing sand pack experiments. Its value is different under different \( \nabla p \).

### 6.3.2 Change of \( \mu_g^f \)

Friedmann et al [1991] used the following expression for gas apparent viscosity when foam is present:

\[ \mu_g^f = \mu_g^0 F_g k^{3/2} n_f (v_{gref}/v_{rref})^{n-1} \text{ for } \mu_g^f > \mu_g \]  

(6-5)

and \( \mu_g^f = \mu_g \) for \( \mu_g^f \leq \mu_g \)
where \( \mu_g \) is gas viscosity without foam, \( F_g \) is a geometric factor and the last term accounts for the shear-thinning nature of the foam. In their simulation approach, \( n_f \) is the foam texture and is calculated by population-balance equations, \( v_g \) is the interstitial gas velocity and \( v_{ref} \) is a reference velocity beyond which the shear thinning effect occurs. \( n \) is the exponent for the shear thinning effect.

However, to solve a population-balance equation, many parameters need to be determined. These parameters are not easy to determine, and so it is not very convenient to apply the equation to field situations. Here, based on their thoughts, instead of solving the population-balance equation, we seek to find some population correlation equation to calculate \( \mu_g' \).

As we mentioned earlier in this chapter, Bertin et al suggested a bubble-population correlation model to calculate foam texture \( n_f \):

\[
n_f = \left( \frac{180(1 - \phi)^2}{\phi^3 k} \right)^{-3/2} S_g x_f \left( \frac{P_c' - P_c(S_w)}{P_c(S_w)} \right)
\]  

(6-6)

He considered the limiting capillary pressure effect in his model. The lamellae become more fragile when capillary pressure increases and are destroyed when \( P_c \) reaches its
Figure 6.1  Relationship between Sg and $n_f$

limiting value $P_r$. Capillary pressure is a function of gas saturation. $x_f$ also mainly depends on gas saturation. So in general, we can simplify Eq. (6-6) into the following way:

$$n_f = C_{nf} F(S_g) \quad (6-7)$$

Where $C_{nf}$ is a constant coefficient and $F(S_g)$ is a function of $S_g$. It implies that

$n_f$ is a function of $S_g$.

Now we need to find a detailed expression for $F(S_g)$ and then for $n_f$. Let's consider a foam generation process when gas invades the porous medium. Figure 6.1 shows a sketch of how the value of $n_f$ changes with the changing of $S_g$. 

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When $S_g = 0$, which means there is no gas inside the porous medium, of course there will be no foam texture, then we can get $F(S_g) = 0$ and $n_f = 0$.

With the increasing of gas saturation, lamellae are generated in the porous medium. During this period, the foam generation rate is greater than the foam coalescence rate. We can call it the lamella density accumulating region. The lamella density value, $n_f$, increases in this region.

With the lamella density continuously accumulating, more and more lamellae are generated inside the porous medium, and the lamella coalescence rate will increase. When the gas saturation is greater than some particular value, $S_{gm}$, the foam generation rate and coalescence rate will be equal to each other. For simplicity we just assume that they remain equal until gas saturation reaches the critical gas saturation $S_g^*$ at which foam breaks. During this period, $n_f$ reaches its maximum value and remains a constant. We can call it lamella density steady state region.

When $S_g \geq S_g^*$ where $S_g^*$ is the saturation at which $P_c(S_g^*) = P_c^*$, the capillary pressure in the porous medium is greater than the limiting capillary pressure. According to the limiting capillary pressure theory, no foam bubbles exist under this condition. So we will get $n_f = 0$ and $F(S_g) = 0$ again.
Following this reasoning, we can define a correlation equation for \( n_f \) as a function of \( S_g \) and derive a expression of \( \mu^f \) in the following format:

When \( S_g < S_{gm} \) in the lamella density accumulating region,

\[
F(S_g) = \left( \frac{S_g}{S_{gm}} \right)^m, \text{ and } n_f = C_{nf} \left( \frac{S_g}{S_{gm}} \right)^m
\]  
\((6-8)\)

Substituting Eq.(6-8) into Eq.(6-5), combining the coefficients \( k^{3/2} C_{nf} \) into a new coefficient \( C_{\mu_f} \) and using the superficial velocity instead of the interstitial velocity, we can get the expression for \( \mu^f \) in this region:

\[
\mu^f = \mu_g F_g C_{\mu_f} \left( \frac{S_g}{S_{gm}} \right)^m \left( \frac{u_g}{u_{ref}} \right)^{n-1}
\]  
\((6-9)\)

When \( S_{gm} < S_g \leq (S_g^* - \epsilon) \), the lamella density steady state region, we have:

\[
F(S_g) = 1, \text{ and } n_f = C_{nf}
\]  
\((6-10)\)

The expression for \( \mu^f_g \) in this region is:

\[
\mu^f_g = \mu_g F_g C_{\mu_f} \left( \frac{u_g}{u_{ref}} \right)^{n-1}
\]  
\((6-11)\)
When \((S_g^* - \varepsilon) < S_g \leq (S_g^* + \varepsilon)\), foam breaks in this transient region,

\[
F(S_g) = \left( \frac{S_g^* + \varepsilon - S_g}{2\varepsilon} \right) \text{ and } n_f = C_f \left( \frac{S_g^* + \varepsilon - S_g}{2\varepsilon} \right) \tag{6-12}
\]

Moreover,

\[
\mu_g^f = \mu_g F_g C_f \left( \frac{S_g^* + \varepsilon - S_g}{2\varepsilon} \right) \left( \frac{u_g}{u_{ref}} \right)^{n-1} \tag{6-13}
\]

When \(S_g > (S_g^* + \varepsilon)\), the capillary pressure is larger than the limiting capillary pressure and no foam exists,

\[
F(S_g) = 0 \text{ and } n_f = 0 \tag{6-14}
\]

In this region where there is no foam,

\[
\mu_g^f = \mu_g \tag{6-15}
\]

Here we defined four foam regions: 1. lamella density accumulating, 2. lamella density steady state, 3. foam breaking transient, 4. no foam region. Actually in our 1-D column
and 3-D sand tank experiments, we only observed the first two regions. In other words, the generated foam is stable enough and didn't break under our experimental conditions. Our investigation and simulation are basically thus limited to these first two regions. But we still list the proposed equations for the last two foam regions here for completeness of the foam model.

### 6.3.3 Model Summary and incorporation into UTCHEM

This model modifies both of the gas relative permeability curve and the apparent gas viscosity to simulate foam flow in porous media.

In this model, there are 9 parameters from these equations: \( S_{r_g}^f, S_{gm}, C_{uf}, u_{ref}, m, n, \)
\( F_g, S_g^* \) and \( \mathcal{E} \).

Among these parameters, \( S_g^* \) and \( \mathcal{E} \) are parameters for the foam breaking transient region and the no foam region. Because in our experiments we did not observe these two regions, we did not try to determine these two parameters in our experiments and just focused our efforts on determining the parameters in the first two foam regions.

Among the remaining parameters, \( S_{r_g}^f, S_{gm}, u_{ref}, m \) and \( n \) can be determined by performing column foam experiments. \( C_{uf} \) is a coefficient which combines the effects of pressure gradient, permeability and surfactant concentration. Its value represents the strength of the generated foam at steady state and can also be determined by 1-D
column experiments. $F_g$ is a geometric factor which represents the effects of flow dimension on foam strength. For simplicity, we just define $F_g$ equal to one in 1-D foam flow. From our experimental observation among 1-D and 3-D experiments, the value of $F_g$ is different for 1-D and 3-D foam flow. The $F_g$ value for 3-D foam flow can be estimated by doing history match simulations.

Following the equations 6-4 and 6-8 to 6-15, the corresponding subroutines in UTCHEM were modified to incorporate the foam model. The Corey model (Eq. 6-4) was used in the simulation. It can avoid the problems of calculating non-wetting phase relative permeability in 3- or 4- phase problems involving more than one non-wetting phase. The corresponding changes were made in the “TRAPG” subroutine. The subroutine “UTFoam” was modified to incorporate the foam effect on gas flow (Eq. 6-8 to 6-15). The two modified subroutines are attached in the Appendix of this thesis.

Besides the modifications of foam model in UTCHEM, a drainage capillary pressure model was also added for the gas phase following the discussions of Tanzil[2001]. The drainage capillary pressure for gas is calculated as follow:

$$P_{cg} = C_{pc} \sqrt{\frac{\phi}{k}} \left(1 - \frac{S_g}{1 - \sum_{l=\text{gas}} S_{sl}}\right)^{-1/4}$$

(6-16)
where $C_{pc}$ is a user defined parameter. The purpose of this drainage capillary pressure is to account for the capillary barrier which exists in the low-permeability regions. It provides a non-zero capillary entry pressure when gas flows from a high permeability into a low permeability region, where the capillary pressure is different because of the different permeability. Also, a capillary entry pressure for gas was added to the gridblocks where the production wells exist. The purpose of this capillary entry pressure is to account for the resistance produced by the screen of the wells when gas flows from the gridblock to the wells. These screens have small resistance to flowing water but have relatively higher resistance to flowing gas. So a separate entry pressure for gas is needed. These modifications were also performed in the “TRAPG” subroutine and can be found in the Appendix.

6.4 1-D column experiments: parameter determination

6.4.1 Experimental

Some 1-D column foam experiments were performed to determine the simulation parameters for the simulation model. The experimental set up is similar to that in the surfactant screening experiment (Figure 4.1). The horizontal column is 1 ft long and packed with 40 darcy or 200 darcy sand. Gas or surfactant solution can be injected from one end of the column and fluids produced from the other end. A pressure transducer is used to record the injection pressure when needed. The only difference
from Figure 4.1 is we were not using co-injection in these parameter determining experiments. Instead, f_g was 100% in these experiments.

6.4.2 Residual saturation with foam

To determine the residual gas saturation inside the column when foam is present, the column was pre-filled with 0.05% CS330+0.05% C13-4PO surfactant solution. Gas was injected into the column at a constant injection pressure. After all of the column was swept by foam and the injection rate reached its steady state, gas injection was turned off and surfactant solution was re-injected into the column under the same constant injection pressure. When the injected liquid volume equals to the produced liquid volume in some time interval, by doing a material balance of the total injected and produced liquid volume, we can calculate the residual gas saturation inside the column. The gas residual saturations for both the 40 darcy and 200 darcy sands were measured. For each of these sands, two different injection pressures, (0.2 psi and 0.4 psi) experiments were performed. Figure 6.2 shows the measured gas saturation vs. injected liquid PV. From the results we can see that for 40 darcy sand, the gas residual saturation when foam was present was about 40%, which did not change much with the change of injection pressure. For 200 darcy sand, the gas residual saturation when foam was present was about 70% and it also did not change much with the change of injection pressure.
6.4.3 Parameters of shear thinning effect ($u_{ref}$ and $n$)

From Eq. (6-9), we can get the following relationship:

$$\ln(\mu_g^f) - (n - 1) \ln(u_g / u_{ref}) = \ln(\mu_g F G C_{f_r}) - m \ln S_{gm} + m \ln S_g$$  \hspace{1cm} (6-17)$$

From this equation, we can find that when the value of $S_g$ is a constant, the right side of the equation will be a constant and there will exist a linear relationship between $\ln(\mu_g^f)$ and $\ln(u_g)$. From the slope of the plot we can get the value of $n$. 

Figure 6.2 Gas residual saturation measurement using 1-D column
The determination of \( m \) depends on which kinds of experiments are performed. If the experiment is performed under constant injection rate, which means \( u_g \) is a constant, then there will be a linear relationship between \( \ln(\mu'_g) \) and \( \ln S_g \). The slope of the plots will be \( m \). For constant injection pressure experiments, we can record every corresponding \( u_g \) for every measured \( S_g \), and a linear relationship will exist between \( \ln(\mu'_g) - (n-1)\ln(u_g / u_{ref}) \) and \( \ln S_g \). The slope of this plot will also be \( m \).

To determine \( u_{ref} \) and \( n \), the column was filled by surfactant solution first and then gas was injected into the column in a high injection pressure, i.e. 7 psi. After all of the column was swept by strong foam and the average gas saturation in the column did not change any more, gas injection was turned off for several minutes to let the inside pressure of the column drop to zero. Then gas was re-injected into the column at different injection rates. The pressure drop for each injection rate was recorded and the corresponding effective gas viscosity calculated using Eq. (6-1) and (6-2). During this process, almost no liquid was produced so the gas saturation in the column was near a constant. Both the 40 darcy and 200 darcy sands were tested to measure the shear thinning effect parameters.

Figure 6.3 shows the plot of gas superficial velocity vs. \( \mu'_g \) for 40 darcy sand column. From this figure we can see when gas superficial velocity is less than about 2 ft/day,
Figure 6.3  Foam shear thinning effect at high velocity, 40 darcy sand

Figure 6.4  Foam shear thinning effect at high velocity, 200 darcy sand

there is no shear thinning effect. When the velocity becomes greater than 2 ft/day, the
shear thinning effect reduces the value of $\mu'_g$ and the value of the power law exponent, $n$, is about 0.2. So for 40 darcy sand, we can get $u_{ref} = 2$ ft/day and $n = 0.2$.

Figure 6.4 shows the results for the 200 darcy sand column. The reference velocity for 200 darcy sand is greater than that for 40 darcy sand. From this figure we can see when gas superficial velocity is greater than about 6 ft/day, the shear thinning effect reduces the value of $\mu'_g$. The value of the power law exponent, $n$, is about 0.4 which is also greater than that for the 40 darcy sand. The values of $u_{ref}$ and $n$ for 200 darcy sand are thus 6 ft/day and 0.4 respectively.

6.4.4 Parameters of gas saturation effect ($S_{gs}$, $m$ and $C_{\mu_f}$)

These three parameters can be determined by doing constant injection pressure foam experiments. The average gas saturation in the column and the injection rate were recorded as a function of time and the corresponding values of $\mu'_g$ were calculated from these records.

- 40 darcy sand column, 0.4 psi constant injection pressure

Figure 6.5 shows the relationship between $\mu'_g$ and $S_g$ in a 0.4 psi constant injection pressure foam experiment for the 40 darcy sand column. From this figure we can see
that with increasing gas saturation, foam effective viscosity also increased. The value of $\mu_\varepsilon^f$ kept increasing when $S_g$ was less than 0.8 and increased dramatically when $S_g$ was between 0.75 and 0.8. But when $S_g$ was greater than 0.8, the value of $\mu_\varepsilon^f$ was approximately constant. So for this experiment, the value of $S_{gm}$ should be around 0.8. When $S_g < S_{gm}$, foam generation rate is greater than foam coalescence rate and the value of $\mu_\varepsilon^f$ increases. When $S_g > S_{gm}$, these two rates are equal and $\mu_\varepsilon^f$ is approximately constant.

Also, from Figure 6.5, we can find that at steady state, the gas saturation is more than 80% and the gas superficial velocity is less than the reference velocity 2 ft/day. So, there was no velocity effect (shear thinning) at steady state. From Eq. 6-11, we can get:
Figure 6.6  Relationship between foam effective viscosity and gas saturation
40 darcy sand, 0.4 psi constant injection

\[ \mu_g^f = \mu_k F_g C_{\mu g} \]  \hspace{1cm} (6-18)

Since we define \( F_g \) to be 1.0 in 1-D foam flow and from Figure 6.5 we can find \( \mu_g^f \)
was about 90 cp at steady state, if we use 0.02 cp as the value of \( \mu_k \), we can calculate
the value of \( C_{\mu g} \). From the calculation, \( C_{\mu g} \) is around 4500.

Figure 6.6 shows the plot of the relationship of \( \{\ln(\mu_g^f) - (n-1)\ln(u_g/u_{ref})\} \) vs.
\( \{\ln S_g\} \) (\( S_g \) is plotted using a log-scale). According to Eq. 6-17, for constant injection
pressure experiments, there should be a linear relationship between them. The slope of
it will be the value of m. From the plots we can see the linear relationship exists and the value of m is around 5.0.

- 40 darcy sand column, 0.2 psi constant injection pressure

A 0.2 psi constant injection pressure experiment was also performed in this 40 darcy column. Figure 6.7 shows the relationship among $S_g$, $\mu_g^f$ and gas superficial velocity. The curves have a similar shape as in the 0.4 psi experimental results. Foam effective viscosity increased with increasing gas saturation and increased dramatically when $S_g$ was between 0.77 and 0.78. The highest $S_g$ which was reached in the 0.2 psi experiment was less than 80%, which is lower than the highest $S_g$ value reached in the 0.4 psi experiment. This is because in the 0.2 psi experiment, the injection pressure was
lower and the generated foam was weaker. Less gas can invade the small pores of the porous medium, which results in a lower gas saturation. In the 0.2 psi constant injection pressure experiment, since the highest gas saturation is lower than 0.8, we can still take the reference $S_g^{m}$ value to be 0.8 in the simulation model. From Figure 6.7 we can also find out that at the steady state, there was no shear thinning effect on foam effective viscosity value. Then from Eq. 6-18, we can determine the value of $C_{\mu_f}$, which is about 2700 for this experiment.

Figure 6.8 shows the plot of the relationship between $\{\ln(\mu_f')-(n-1)\ln(u_g/u_{ref})\}$ and $\ln S_g$ ($S_g$ is plotted using a log-scale). From the slope of the plot we get the value of $m$, which is around 5.6. Compared to the $m$ value, 5.0, in the 0.4 psi experiment, the
value of $m$ did not change much with the change of injection pressure. It is reasonable that $m$ is a little larger in the 0.2 psi injection pressure experiment because the pressure gradient is lower and it should take a longer time to reach the same foam strength compared to the 0.4 psi injection pressure experiment. But since these two $m$ values are not greatly different, for simplicity, we just take $m$ to be 5.0 for both injection pressures in our simulations.

- 200 darcy sand column, 0.4 psi constant injection pressure

Figure 6.9 shows the relationship among $S_g$, $\mu_g'$ and gas superficial velocity for the 200 darcy sand column under 0.4 psi constant injection pressure. The value of $\mu_g'$
increased with increasing $S_g$. The highest gas saturation we reached in this experiment was about 0.85. However, we did not observe a plateau in this plot where $\mu^f_g$ did not change much with changing $S_g$. The plateau may exist for some higher gas saturation values, but in this experimental condition, it hadn’t been reached. The value of $S_{gm}$ should be between 0.85 and the water residual saturation. Since the value of 0.85 is already very high and very close to the water residual saturation, we just choose 0.85 as the value of $S_{gm}$. The simulated results will not change much by making this simplification. At steady state, the value of $\mu^f_g$ reached its highest value, which was about 9 cp. The superficial gas velocity at steady state was about 23 ft/day, which was higher than the reference gas velocity (6 ft/day) determined in our shear thinning effect.
experiment. From Eq. 6-11, we can calculate that $C_{\mu_f}$ was about 1200 for this experiment. Figure 6.10 shows the plot of the relationship between $\{\ln(\mu_g^f) - (n-1)\ln(u_g/u_{ref})\}$ and $\{\ln S_g\}$ ($S_g$ is plotted using a log-scale). From this plot we can determine the value of $m$, which was about 12 for this experiment.

- 200 darcy sand column, 0.2 psi constant injection pressure

A low injection pressure experiment with 0.2 psi constant injection pressure, was also performed in this 200 darcy sand column. Figure 6.11 shows the relationship among $S_g$, $\mu_g^f$ and gas superficial velocity. At steady state, the highest gas saturation value reached was also about 85%, and again we did not observe a plateau in the $\mu_g^f$ curve.

As in the 0.4 psi constant injection pressure experiment, we take $S_g^{gm}$ to be the steady
state $S_g$ value, 0.85. In this experiment, at steady state, the highest value of $\mu_s^f$ was about 8 cp. The superficial gas velocity at steady state was about 13 ft/day, which is still larger than the reference gas velocity. Again, from Eq. 6-11, we can calculate the value of $C_{uf}$ for this experiment, which was about 650. Figure 6.12 shows the plot of the relationship between $\{\ln(\mu_s^f) - (n-1)\ln(u_g/\bar{u}_{ref})\}$ and $\{\ln S_g\}$. We found that the value of $m$ was still about 12, the value for the 0.4 psi constant pressure injection experiment.

<table>
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<tr>
<th>1-D column</th>
<th>Injection pressure</th>
<th>$S^f_{rg}$</th>
<th>$u_{ref}$</th>
<th>$n$</th>
<th>$S_{gm}$</th>
<th>$m$</th>
<th>$C_{uf}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>40 darcy</td>
<td>0.4 psi</td>
<td>0.4</td>
<td>2 ft/day</td>
<td>0.2</td>
<td>0.80</td>
<td>5</td>
<td>4,500</td>
</tr>
<tr>
<td></td>
<td>0.2 psi</td>
<td>0.4</td>
<td>2 ft/day</td>
<td>0.2</td>
<td>0.80</td>
<td>5</td>
<td>2,700</td>
</tr>
<tr>
<td>200 darcy</td>
<td>0.4 psi</td>
<td>0.7</td>
<td>6 ft/day</td>
<td>0.4</td>
<td>0.85</td>
<td>12</td>
<td>1,200</td>
</tr>
<tr>
<td></td>
<td>0.2 psi</td>
<td>0.7</td>
<td>6 ft/day</td>
<td>0.4</td>
<td>0.85</td>
<td>12</td>
<td>650</td>
</tr>
</tbody>
</table>

Table 6.1 Parameters determined from 1-D column experiments
Table 6.1 lists the parameters we determined from the 1-D column experiments for 40 darcy and 200 darcy sands under 0.4 psi and 0.2 psi constant injection pressure.

6.5 Simulation results: comparison between 1-D and 3-D

6.5.1 1-D column simulation results

The determined foam model parameters were used to simulate the corresponding 1-D column foam experiments. Figure 6.13, 6.14, 6.15, 6.16 show the simulated injection rate compared to the experimental result for 40 darcy and 200 darcy sands under 0.4 and 0.2 constant injection pressures. The simulated results matched the experimental results. Table 6.2 compares simulated and experimental average gas saturations. The simulated gas saturation matched the experimental results. From these comparisons we can see the 1-D column experimental results can be simulated and matched by using the proposed foam model and determined parameters.

<table>
<thead>
<tr>
<th>0.05%CS-330</th>
<th>40 darcy sand column</th>
<th>200 darcy sand column</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.05%C13-4PO fg=100%</td>
<td>0.4 psi</td>
<td>0.2 psi</td>
</tr>
<tr>
<td>Sg</td>
<td>Experimental</td>
<td>82%</td>
</tr>
<tr>
<td></td>
<td>Simulated</td>
<td>84%</td>
</tr>
</tbody>
</table>

Table 6.2 Comparison of simulated and experimental gas saturation
Figure 6.13 1-D column simulation results vs. experimental data
40 darcy sand, 0.4 psi constant injection pressure

Figure 6.14 1-D column simulation results vs. experimental data
40 darcy sand, 0.2 psi constant injection pressure
200 darcy sand, 0.4 psi constant pressure, 0.05% CS330 + 0.05% C13-4PO fg=100%

Steady state gas saturation:
Exp: 85%
Simu: 86%

Figure 6.15 1-D column simulation results vs. experimental data
200 darcy sand, 0.4 psi constant injection pressure

200 darcy sand, 0.2 psi constant pressure, 0.05% CS330 + 0.05% C13-4PO fg=100%

Steady state gas saturation:
Exp: ~85%
Simu: ~84%

Figure 6.16 1-D column simulation results vs. experimental data
200 darcy sand, 0.2 psi constant injection pressure
6.5.2 3-D tank simulation results

6.5.2.1 Homogeneous sand tank simulations

Following the 1-D column simulations, we conducted 3-D sand tank history match simulations using the parameters obtained in the 1-D simulations.

- ~0.8 psi constant injection pressure, homogeneous, air/water

The first simulation is a history match simulation for the air/water experiment in the homogeneous 3-D tank. The details of the sand tank and this experiment are described in Chapter 5, 5.1.2.1. Figure 6.17 shows the comparison of experimental and simulated injection rates for this air/water experiment. From the plot we can see the simulation
Homogeneous Sand Tank, Air/Water experiment

Experimental Results
Gas saturation: 23\%

Simulated Results
Gas saturation: 28\%

Figure 6.18  Gas fractional flow contour plots, diagonal cross section
~0.8 psi constant pressure injection, 6 PV gas injected

results matched the experimental results well. After 6 PV gas injected, the simulated average gas saturation was about 28% which is close to the experimental result of 23%.

Figure 6.18 shows the comparison of the diagonal cross section gas fractional contour plots. The simulated result matched the experimental result in most parts of the tank except for some difference at the bottom of the tank. The reason for this was due to the heterogeneity of the sand pack. It was not perfectly homogeneous. The bottom gas fractional flow contour plot (Figure 5.7 of Chapter 5) shows this heterogeneity. Gas front along the diagonal propagated much farther than the gas fronts in other flow directions. So when we plot the results along the diagonal cross section of the tank, it seems that gas contacted much of the volume of the bottom but in fact there still remains a large volume of the bottom unswept by gas (Figure 5.7). In a simulation, it is difficult to include this particular heterogeneity. So the diagonal cross section contour
plots only cannot give the complete picture of the gas fractional flow everywhere in the tank.

<table>
<thead>
<tr>
<th></th>
<th>$k_r^0$</th>
<th>$S_{rl}$</th>
<th>$e_l$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>1.0</td>
<td>0.1</td>
<td>2.3</td>
</tr>
<tr>
<td>Gas</td>
<td>1.0</td>
<td>0.05</td>
<td>1.5</td>
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</tbody>
</table>

Table 6.3 Parameters of the relative permeability curve

Table 6.3 gives the parameters of the relative permeability equations (Eq. 6.4) for both water and gas without foam. These parameters were verified by the 3-D sand tank air/water history match simulation and will be applied throughout the simulation study of this thesis.

After the history match simulation for the air/water experiment, the 3-D homogeneous foam experiments discussed in Chapter 5 were also simulated using the modified simulator. The overall pressure gradients in the tank experiments were used as the comparison standard to compare to the corresponding 1-D column experiments. For example, in the 0.8 psi constant injection pressure tank experiment, the overall pressure gradient was about 0.4psi/ft, which was the same as the pressure gradient in the 0.4 psi constant pressure 1-D column experiment and the parameters obtained from this 1-D column experiment will be used to simulate the 3-D tank experiment. For the 0.39 LPM constant injection rate experiment, since the measured injection pressure reached and remained 0.4 psi almost from the beginning of the experiment, we just use the 0.2 psi constant injection pressure 1-D column experiment results as its comparison
standard since both these experiments have a constant overall pressure gradient of about 0.2 psi/ft.

In our 3-D sand tank simulations, we kept all the parameters the same as in the 1-D column simulations except for the value of $F_g$. This value represents the effect of flow dimension on foam strength. To get the best match simulation results, we needed to choose a smaller $F_g$ value for the tank simulations than for the 1-D column simulations. In 1-D foam flow, for convenience, we defined this value to be one. In 3-D simulations, we found this value must be set to be around 0.21 to get the best match results, as is seen below.

- 0.8 psi constant injection pressure, homogeneous, foam

For the 0.8 psi constant injection pressure 3-D foam experiment, Figure 6.19 shows the simulated injection rate compared to the experimental data. Agreement is good for both the rate and the average gas saturation. After around 1 PV gas was injected, the simulated average gas saturation inside the tank was about 69% and the experimental data is 66%. Figure 6.20 shows the simulated gas fractional flow contour plots compared to the experimental data. After about 1 PV gas injected, gas contacted more than 75% of the cross sectional area of the tank. Figure 6.21 shows the simulated inside pressure profile compared to the experimental data. From the pressure profile we can see that the highest pressure drop is around the middle part of the tank. The
region near the injection well (p1) has a lower pressure drop compared to the middle region (p2).
Figure 6.21 Homogeneous 3-D sand tank, foam, pressure profile
0.8 psi constant injection pressure

Homogeneous Sand Tank

Experimental Results
Gas saturation: 37\%

Simulated Results
Gas saturation: 33\%

Figure 6.22 Gas fractional flow contour plots, diagonal cross section
0.39 LPM constant injection rate, 1 PV gas injected

➢ 0.39 LPM constant injection rate (0.4 psi), homogeneous, foam

For the 0.39 LPM constant injection rate (0.4 psi) 3-D foam experiment, Figure 6.22 shows the simulated gas fractional flow contour plots match the experimental data well.
The average gas saturation values are also in good agreement. In this experiment, the average gas saturation after about 1 PV gas injected was about 37%, compared to the simulated result of about 33%. Figure 6.23 shows the comparison between the simulated pressure profile and the experimental data. Just as in the 0.8 psi foam experiment, the pressure drop near the injection well (p1) is lower than that in the farther region of the tank (p2). Experiments show that foam flow in 1-D is stronger than in 3-D. The reason for this phenomenon is not fully understood but may be related to the fact that more diverging pathways are available for gas flow in 3-D. As indicated above, we defined a dimensional parameter $F_x$ to represent this behavior and found that its value is about 0.21. That is, under the same conditions in our experiments, the 3-D foam flow is 5 times weaker than the 1-D foam flow.
6.5.2.2  Heterogeneous sand tank simulations

These simulations were also history match simulations for the 3-D heterogeneous foam experiments discussed in Chapter 5. The configuration of the heterogeneous packing is shown in Figure 5.3. We did not try to history match the heterogeneous air/water experiment. It is because the heterogeneous pack was repacked by using the sand from the homogeneous pack, which may contain small amount of surfactant left from the homogenous foam experiments and slightly affect the flow of air in it. Though the air/water experiment in the heterogeneous pack can still show reasonable results qualitatively, these results are not good for a quantitative history match approach. In the foam history match simulations, for both the 40 darcy sand and the 200 darcy sand, we kept most of the parameters obtained from 1-D column experiments the same. We only changed the value of $C_{\mu f}$ between 1-D and 3-D to get the best match results.

Table 6.4 lists the parameters which were chosen for the best match simulations. From this table we can see if we keep the $F_g$ value the same as that found from the homogeneous sand tank simulations, the value of $C_{\mu f}$ in the high permeability layer needs to be higher than in the 1-D column experiments to get the best match to experimental results. For example, in the 200 darcy column experiment, $C_{\mu f}$ is found to be about 1200, but in the 3-D heterogeneous simulation, keeping $F_g$ as 0.21, a higher $C_{\mu f}$ value (3100) is needed which is about 3 times larger than the 1-D column
<table>
<thead>
<tr>
<th></th>
<th>$S_g^f$</th>
<th>$u_{ref}$</th>
<th>$N$</th>
<th>$S_{gw}$</th>
<th>$M$</th>
<th>$C_{pf}$</th>
<th>$F_g$</th>
</tr>
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<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
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<td>0.4</td>
<td>2</td>
<td>0.2</td>
<td>0.80</td>
<td>5</td>
<td>4,500</td>
<td>1.00</td>
</tr>
<tr>
<td><em>(1-D column, 1 ft)</em></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.8 psi constant injection pressure</td>
<td>0.4</td>
<td>2</td>
<td>0.2</td>
<td>0.80</td>
<td>5</td>
<td>4,500</td>
<td>0.21</td>
</tr>
<tr>
<td><em>(3-D tank, 2x2x2 ft)</em></td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>0.2 psi constant injection pressure</td>
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<td>2</td>
<td>0.2</td>
<td>0.80</td>
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<td></td>
</tr>
<tr>
<td><strong>Heterogeneous Sand (40 &amp; 200 darcy sand)</strong></td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Case 1: 0.8psi constant injection pressure</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>High perm (200 darcy)</td>
<td>0.7</td>
<td>6</td>
<td>0.4</td>
<td>0.85</td>
<td>12</td>
<td>1,200</td>
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<tr>
<td><em>(1-D column)</em></td>
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<tr>
<td>3-D sand tank</td>
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<td>0.4</td>
<td>0.85</td>
<td>12</td>
<td>3,100</td>
<td>0.21</td>
</tr>
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<td><strong>Case 2: 0.4psi constant injection pressure</strong></td>
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<td></td>
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</tr>
<tr>
<td>High perm (200 darcy)</td>
<td>0.7</td>
<td>6</td>
<td>0.4</td>
<td>0.85</td>
<td>12</td>
<td>650</td>
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<td><em>(1-D column)</em></td>
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<td></td>
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<tr>
<td>3-D sand tank</td>
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<td>0.4</td>
<td>0.85</td>
<td>12</td>
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</tr>
<tr>
<td>Low perm (40 darcy)</td>
<td>0.4</td>
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<td>0.2</td>
<td>0.80</td>
<td>5</td>
<td>4,000</td>
<td>0.21</td>
</tr>
</tbody>
</table>

Table 6.4  Comparison of parameters for 1-D and 3-D simulation

value. This can be explained by the foam generation mechanism of snap-off. When gas flows from a low permeability region to a high permeability region, because of the change of capillary pressure, foam can be generated along the boundary between the regions by snap-off and hence the effective foam viscosity can be increased.

- 0.8 psi constant injection pressure, heterogeneous, foam

Figure 6.24 shows the comparison of simulated and experimental injection rates for the 0.8 psi constant injection pressure experiment. The simulated average gas saturation
after 1 PV gas injected was about 73%, while the corresponding experimental result was about 82%. Figure 6.25 shows the gas fractional flow contour plots after 1 PV gas injected. We can see that most of the bottom of the tank was contacted by gas.
Figure 6.26  Heterogeneous 3-D tank, 0.8 psi constant injection pressure
Pressure profile

Compared to Figure 6.22 for the homogeneous case, lateral gas transport along the bottom of the tank was greatly increased. Figure 6.26 shows the simulated pressure profile compared to the experimental data. The strongest foam region is in the middle part of the tank.

- 0.4 psi constant injection pressure, heterogeneous, foam

Another history match simulation was performed to simulate the 0.4 psi constant injection pressure foam experiment. Table 6.4 also lists the simulation parameters for this experiment. Because the injection pressure is lower than in the 0.8 psi case, the value of $C_{\mu f}$ was also lower. From the best history match results, we can still find that the value of $C_{\mu f}$ in 3-D is larger than in 1-D column experiments. For the high
permeability layer, the value of $C_{\mu f}$ increased more than 3 times and in the low permeability region, the value of $C_{\mu f}$ also increased from 2700 to 4000. Thus, in this case the heterogeneity not only increased the foam strength in the high permeability region but also increased the foam strength in the low permeability region. Figure 6.27
Figure 6.29  Heterogeneous 3-D tank, 0.4 psi constant injection pressure
Pressure profile

shows the comparison of simulated and experimental injection rates for the 0.4 psi constant injection pressure experiment. Figure 6.28 shows the comparison of gas fractional flow plots after 1 PV gas injected. The simulated average gas saturation after 1 PV gas injected was about 68%, and the experimental result was about 60%. Figure 6.29 shows the simulated and experimental pressure profiles. The simulated pressure profile matched the experimental results. The simulated highest pressure drop was also in the P2 region, just as the result from the experiment.
6.5.2.3 Sensitivity study of $C_{\mu f}$

The most important parameter in this foam model which may affect the simulation results is the value of $C_{\mu f}$. Some simulations were performed to investigate the sensitivity of this parameter. Figure 6.30 shows the simulated injection rates for the constant 0.8 psi over hydrostatic pressure, homogeneous 3-D foam case. Different $C_{\mu f}$ values were used but with the other parameters kept the same as in the best match simulation. From the plots we can see when the $C_{\mu f}$ value changed within a $\pm 5\%$ range, the simulated injection rates did not change compared to the best match result and these results were acceptable. These results also show that the simulated injection
Homogeneous sand pack, ~0.8 psi constant pressure, diagonal cross section, gas fractional flow contour plots

\[ C_{\mu f} = 4250 \quad C_{\mu f} = 4500 \quad C_{\mu f} = 4750 \]

Simu Sg=65%  Simu Sg=69%  Simu Sg=71%

Figure 6.31 Comparison of the gas fractional contour plots, Different \( C_{\mu f} \) value, 1 PV gas injected

rate has a negative relationship with the value of \( C_{\mu f} \): the larger the \( C_{\mu f} \) value, the smaller the simulated rate. This is explainable because \( C_{\mu f} \) represents the steady state foam strength. So a larger \( C_{\mu f} \) value indicates stronger foam and lower gas flow rate.

Figure 6.31 compares the simulated gas fractional flow contour plots along the diagonal cross section of the tank when 1 PV gas was injected. From this figure we can see for these three different \( C_{\mu f} \) values, the differences on the simulated gas fractional flow plots were very small. The simulated total gas saturations were also close. For the case of \( C_{\mu f} \) equals to 4250, the simulated gas saturation was about 65%, which was 4% less than the best match result. For the case of \( C_{\mu f} \) equals to 4750, the simulated gas saturation was only 2% higher than the best match result.
Figure 6.30 and 6.31 present the sensitivity of the change of $C_{\mu f}$ value on the simulated results. When $C_{\mu f}$ value changes in a $\pm 5\%$ range, the simulated results for injection rate, gas saturation and gas sweep are acceptable. From Figure 6.31 we can also see that the gas sweep profiles were hardly changed with the change of $C_{\mu f}$. The value of $C_{\mu f}$ can be changed in a broader range than $\pm 5\%$ when only the gas sweep profiles are wanted.

6.6 Discussion and summary

Foam generation is a complex process. For different experimental conditions, i.e. different surfactant concentrations, different injection pressures or injection rates, the generated foam strength may vary. A foam simulation model is presented in this chapter with the objective of simulating foam flow in 3-D by doing only 1-D experiments to evaluate key parameters. In this model, when foam is present, both the gas relative permeability curve and the apparent viscosity of the gas are changed. The gas relative permeability curve changed because of the increased trapped gas saturation. The apparent viscosity is defined as a function of gas saturation, gas velocity and flow dimension. Most of its parameters can be determined by 1-D column experiments. Foam flow simulations for a homogeneous 3-D tank were performed using the parameters determined from the 1-D column experiments. A value for $F_g$ of about 0.21 was found to be needed to history match the 3-D homogeneous tank results of
Chapter 5 above. This represents an effective decrease in foam strength in 3-D possibly due, among other things, to the presence of more diverging pathways for gas to flow through the sand. Taking this $F_g$ value, additional simulations were performed for a heterogeneous sand pack like that in the experiments of Chapter 5. From the history match with the experiments, we found that foam strength is increased because of heterogeneity. In the high permeability layers, the foam strength parameter $C_{\mu f}$ increased about 3 times possibly owing to snap-off which occurred as gas entered these layers from the underlying low-permeability layers. In the low permeability region, the value of $C_{\mu f}$ increased by about 50% for one of the two experiments but was the same as for the homogeneous tank in the other experiment.
Chapter 7

HYPOTHETICAL FIELD APPLICATION DESIGN

As our 2-D and 3-D foam experiments have demonstrated, foam can improve the gas sweep efficiency and increase gas saturation in porous media. As we discussed in Chapter 3, a new application of foam is in the area of aquifer remediation. In an aquifer remediation process using surfactants, foam was used for mobility control to displace DNAPL from low permeability sands that are often unswept during such processes. The first field demonstration of the surfactant/foam process for removal of DNAPL from a heterogeneous, alluvial sand was conducted at Hill Air Force Base in Utah [Hirasaki et al 1997, 2000]. Following the surfactant/foam process, a bioremediation process can be applied to the aquifer to dechlorinate the remaining chlorinated compounds. Direct hydrogen addition, where hydrogen is delivered without the use of fermentation substrates or carbon sources, is an in-situ bioremediation technology [Hughes et al, 1997]. In this process, hydrogen acts as an electron donor and halogenated compounds such as chlorinated solvents act as electron acceptors that are reduced in the reductive dechlorination process. Hydrogen can be delivered to the aquifer by sparging with an injection well as is done during biosparging. But due to the low density and viscosity of hydrogen, hydrogen injected at the base of the aquifer
tends to flow upwards and cannot contact much of the bottom of the aquifer laterally [Newell et al, 2000, 2001]. The role of foam in hydrogen biosparging is to promote the lateral transport of gas in the aquifer to contact the contaminants in the bottom of the aquifer, especially when the contaminants are DNAPL.

In this chapter, we will design a hypothetical field application of hydrogen foam. The necessary conditions, which are required for a successful field foam application on aquifer remediation, are investigated.

7.1 Preliminary experiments for field application

Before designing a hypothetical field application, some experiments and simulations are needed to answer several questions which will be encountered in a field application.

7.1.1 Threshold surfactant concentration

In our previous 1-D or 3-D sand pack experiment, the surfactant concentration was high enough to generate foam wherever gas was present. But in a field application, the smaller pore volume of surfactant injected prior to foam and the lack of confinement may allow gas to overtake the surfactant front. There may be some places where surfactant concentration is not high enough to generate strong foam. It is important to
Figure 7.1 Surfactant concentration effect on steady state foam effective viscosity

know the threshold surfactant concentration below which strong foam cannot be generated.

Some 1-D foam experiments were performed using solutions of different surfactant concentrations to test the foamabilities of these surfactants. The experiments were performed in a 40 darcy sand column and the surfactant chosen was still the surfactant mixture of CS-330 and C13-4PO with an active weight ratio of 1:1. Different total concentrations were tested. Figure 7.1 shows the experimental results. Note that the effective foam viscosity drops dramatically when the total surfactant concentration is lower than 0.02%. So, in our simulation, we just set the threshold surfactant concentration to be 0.02% and set 0.02%±0.002% to be the transition region. When the total surfactant concentration is greater than 0.022%, the surfactant solution has
the ability to generate strong foam. And just for simplicity, when surfactant solution concentration is higher than 0.022%, we will take the steady state foam effective viscosity to be that of the 0.1% surfactant solution. When the total surfactant concentration is less than 0.018%, the surfactant solution is assumed to be too dilute to generate any foam. When the total surfactant concentration is between 0.018% and 0.022%, it is in a transition region and foam strength drops linearly. The dashed line in Figure 7.1 shows the simplified curve we used in our simulations.

7.1.2 Minimum amount of surfactant solution needed

After we determined the threshold surfactant concentration, the next step is to determine the amount of surfactant solution needed for the field application. In our 3-D tank experiments, the tank was filled with surfactant solution before any gas was injected. In a field application, one would not inject such a large amount of surfactant because it is not efficient and indeed not feasible to fill the aquifer with surfactant solution. Here we will perform some simulations to determine the minimum amount of surfactant solution required. If normal air sparging technology is used, much of the bottom portion of the aquifer cannot be contacted by hydrogen. So in the hydrogen biosparging foam field application, the most important issue is to distribute the injected hydrogen throughout the whole aquifer, especially near the bottom. We did several simulations in our 3-D tank model and compared the gas distribution difference along the bottom sampling layer. In these simulations, different fractional PV quantities of
Experimental Results, Full of surfactant before gas injection,
After 1 PV gas injected, Sg: 66%

Simulated Results, different PV surfactant solution injected:

*Full of surfactant, Sg:69%
0.5 PV surfactant, Sg: 69%
0.25 PV surfactant, Sg: 67%
0.125 PV surfactant, Sg: 55%
0.1 PV surfactant, Sg: 50%
0.05 PV surfactant, Sg: 40%*

*Figure 7.2 Effect of different surfactant amount on foam sweep efficiency
Comparison based on a homogeneous 3-D sand tank foam experiment,
0.8 psi over hydrostatic constant injection pressure, bottom sampling layer*

surfactant solution were injected prior to gas injection, and after 1 PV gas was injected,
the simulated bottom layer gas distribution profiles were compared with the experimental results. Figure 7.2 shows the comparison. From these figures we find
that, when the amount of injected surfactant solution is greater than 0.25 PV, there is almost no difference in the gas swept area of the bottom sampling layer. The total average gas saturation after 1 PV gas injected also did not change. Beginning from the 0.125 PV surfactant injection case, the gas sweep efficiency and the average gas saturation decreased with decreasing volume of injected surfactant solution. From these comparisons, we conclude that the threshold surfactant volume which is needed to get the same results as when the aquifer is initially full of surfactant is between 0.125 and 0.25 PV. Taking a conservative estimation, we choose 0.2 PV to be the minimum surfactant amount needed to be injected in a field application.

7.1.3 Effect of injection pressure on simulation parameters

In our previous 3-D sand tank foam experiments discussed in Chapter 5, the highest injection pressure we tested was only 0.8 psi over hydrostatic pressure. In a field application, a higher injection pressure may be required to increase the injection efficiency. So it is necessary for us to find out how the simulation parameters change with changing of injection pressure.

Some 1-D foam experiments were performed in 40 darcy and 200 darcy 1-ft sand columns to investigate the effect of different injection pressure (or different overall pressure gradient) on foam strength and the value of simulation parameters. Figure 7.3 shows the value of the steady state foam viscosity at different pressure gradient for the
Figure 7.3 Steady state foam effective viscosity at different pressure gradient

40 darcy and 200 darcy 1 ft sand columns. From this figure we can see that when the overall pressure gradient is low, the generated foam is not strong and the steady state effective foam viscosity is also low. With increasing of the overall pressure gradient, the effective foam viscosity also increases. Shear thinning effect will reduce the effective foam viscosity when the overall pressure gradient is high enough. This shear thinning effect is beneficial because it allows strong foam without excess pressure limitation near the injection well where the velocity is high. So in a foam process, the overall pressure gradient should be high enough for satisfactory performance. Table 7.1 lists the simulation parameters found for the different injection pressure experiments. From the table we can see that these five parameters: $S_{rg}$, $u_{ref}$, $n$, $S_m$, $m$ do not change much with changing injection pressure, where $S_{rg}$ is the gas residual saturation.
<table>
<thead>
<tr>
<th>Injection pressure</th>
<th>( S_{ref} )</th>
<th>( u_{ref} ) ( \text{ft/day} )</th>
<th>( n )</th>
<th>( S_{gm} )</th>
<th>( m )</th>
<th>( C_{\mu f} )</th>
<th>( F_g )</th>
</tr>
</thead>
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<tr>
<td>40 darcy sand column</td>
<td>0.2 psi</td>
<td>0.4</td>
<td>2</td>
<td>0.2</td>
<td>0.8</td>
<td>5.60</td>
<td>2,700</td>
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<tr>
<td></td>
<td>0.4 psi</td>
<td>0.4</td>
<td>2</td>
<td>0.2</td>
<td>0.8</td>
<td>5.04</td>
<td>4,500</td>
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<tr>
<td></td>
<td>0.8 psi</td>
<td>0.4</td>
<td>2</td>
<td>0.2</td>
<td>0.8</td>
<td>5.08</td>
<td>8,010</td>
</tr>
<tr>
<td></td>
<td>1.6 psi</td>
<td>0.4</td>
<td>2</td>
<td>0.2</td>
<td>0.8</td>
<td>4.92</td>
<td>8,080</td>
</tr>
<tr>
<td>200 darcy sand column</td>
<td>0.2 psi</td>
<td>0.7</td>
<td>6</td>
<td>0.4</td>
<td>0.84</td>
<td>12.10</td>
<td>650</td>
</tr>
<tr>
<td></td>
<td>0.4 psi</td>
<td>0.7</td>
<td>6</td>
<td>0.4</td>
<td>0.84</td>
<td>11.77</td>
<td>1,200</td>
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<tr>
<td></td>
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<td>11.65</td>
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<td></td>
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<td>0.4</td>
<td>0.84</td>
<td>11.40</td>
<td>3,150</td>
</tr>
</tbody>
</table>

Table 7.1 Simulation parameters under different injection pressure

when foam is present, \( u_{ref} \), \( n \) are the parameters representing the shear thinning effect on the strength of foam and \( S_{gm} \), \( m \) are the parameters representing the saturation effect on the strength of foam (see details in Chapter 6). The only parameter which does change is \( C_{\mu f} \), which represents the steady state foam strength. Figure 7.3 shows a plot of \( C_{\mu f} \) as a function of overall pressure gradient. From this plot we can find that when the pressure gradient is higher than some threshold value, i.e. 0.6~0.8 psi/ft in the 40 darcy column and \( \sim 1.5 \) psi/ft in the 200 darcy column, the \( C_{\mu f} \) value reaches its maximum value and levels off. When the overall pressure gradient is greater than the threshold value, \( C_{\mu f} \) does not change with further increase of the overall
pressure gradient. So, during a foam process, when the pressure gradient is high enough, i.e. higher than the threshold pressure gradient, all of the simulation parameters will be the same including the $C_{uf}$ value (at its maximum value). When the pressure gradient is lower than the threshold pressure gradient, the value of $C_{uf}$ will be lower than its maximum value and weaker foam will be generated at steady state, as shown in Figure 7.4.

The parameters we determined here are for the surfactant mixture at 0.1% total active concentration. They will surely vary to some extent with the change of the surfactant composition and concentration (which means the foamability of the solution changes). For different surfactant solutions, one may need to do additional experiments to determine the corresponding simulation parameters. But in general, the surfactant
mixture used here should be representative of good foamers, and the conclusions for this mixture should be applicable for other good foaming surfactants.

In our previous 3-D tank experiments, the highest injection pressure we have tested was 0.8 psi over hydrostatic pressure (the overall pressure gradient was 0.4 psi/ft). From Figure 7.4 we can see at this overall pressure gradient, the value of $C_{\mu f}$ is less than its maximum value. In a field application, usually the injection pressure is much higher and $C_{\mu f}$ will then be at its maximum value. So it is useful for us to investigate how foam behaves under higher injection pressure where $C_{\mu f}$ is in its maximum value. A 3-D tank foam experiment was performed in the heterogeneous sand pack using a higher injection pressure. In this experiment, the injection pressure was about 1.6 psi.
over hydrostatic pressure (overall pressure gradient was 0.8 psi/ft) and the $C_{nf}$ value was near its maximum value. Figure 7.5 shows the comparison of the experimental results between this 1.6 psi case and a lower injection pressure (0.8 psi) case. These plots are the gas fractional flow contour plots along the diagonal cross section of the tank when different PVs of gas were injected. From Figure 7.5 we can see, when 0.37 PV gas was injected, it is obvious that more of the bottom volume of the tank was swept by gas in the 1.6 psi case than in the 0.8 psi case. After 1 PV and 2 PV gas was injected, because in both these two cases the gas sweep efficiency was already very high, the results of these two cases were similar. But in the 1.6 psi case, gas still swept slightly more bottom volume than in the 0.8 psi case and the obtained average gas saturation was also slightly higher. For the injectivity, Figure 7.6 shows a plot of the injection rate
vs. injection time for the 1.6 psi case. By comparing the injection rate curve with the results of the 0.8 psi case (Figure 5.11), we can see at steady state, the injection rate in the 1.6 psi case is higher than in the 0.8 psi case (~1 LPM). From these comparisons we can find that the higher injection pressure can increase the gas sweep along the bottom of the sand tank and also increase the average gas saturation (Figure 7.5). High injection pressure can benefit the generation and propagation of strong foam farther away from the injection well. And at the same time, the injectivity can still be good because the shear thinning effect will aid the injectivity by reducing the foam apparent viscosity around the injection well. So in general, to get satisfactory performance in a field foam application process, a high injection pressure is desirable.

7.2 Extend to field scale simulation

The foam simulation model has been described in Chapter 6. The model sets a connection between 1-D foam and 3-D foam. Parameters obtained from 1-D column experiments can be applied to 3-D foam simulations and only one geometric parameter, $F_{gs}$, is changed due to the difference of foam strength in 1-D and 3-D flow. We found that if the $F_{g}$ value is defined as 1.0 in 1-D foam flow, then in the 3-D simulation, this value should be set to about 0.21 to get the best history match results. We will use this 1-D and 3-D relationship in our scaling up simulations.
To extend to field scale simulation, we use a pressure gradient which is calculated by using the injection pressure (over hydrostatic) divided by 2 ft as a comparison standard to the 1-D column. For example, for an 8 psi over hydrostatic pressure injection case, the calculated pressure gradient will be 4 psi/ft and then we will choose the simulation parameters from the corresponding 4 psi/ft 1-D experimental results. The reason we choose 2 ft here is because it is the same dimension as the 3-D tank in our lab and the $F_g$ relationship we found is based on this dimension. Also, we assume the generated foam within the 2 ft dimension can propagate farther away and keep the same strength. For the simulation parameters, as we discussed earlier in this chapter, we found that these simulation parameters will keep the same when the pressure gradient is higher than some threshold value, i.e. 0.6~0.8 psi/ft for the 40 darcy sand and ~1.5 psi/ft for the 200 darcy sand.

The other issue we need to consider in a field simulation is the shear thinning effect between the well bore and the grid block. In the 3-D tank simulations in Chapter 6, we modeled the shear thinning effect among grid blocks. Because in our 3-D tank, the pressure difference between the well bore and the nearest grid block is very small, the shear thinning effect is also small between them and can be ignored. But in the field simulation, because the grid block is much bigger than the well bore, there will be a significant velocity/viscosity difference between the well bore and the grid block, just as the velocity and viscosity profiles shown in Figure 7.7. We need to consider the shear thinning effect between them in our field simulation and add a model for it in the
Figure 7.7 Velocity and viscosity profiles from the injection well (radial flow)

simulator. Following the discussion of Bondor, Hirasaki and Tham[1972] on a well model of polymer injection, we added a negative, rate-dependent apparent skin factor $S_p$ in the well model to represent the non-Newtonian effects between the well bore and the gridblock,

$$S_p = \frac{1}{(1-n)} \left[ \ln(v^N N_u^{(1-v)}) - v + 1 \right] \quad \text{when } N_u \leq v \quad (7-1)$$

and

$$S_p = \frac{1}{(1-n)} \left[ \ln(N_u^N) - N_u + 1 \right] \quad \text{when } N_u > v \quad (7-2)$$

There $n$ is the exponent of the shear thinning effect, $v$ is the ratio between the minimum viscosity and the viscosity of the gridblock which contains the injection well $v = \frac{\mu_{\text{min}}}{\mu_{\text{gridblock}}}$. $N_u$ is a dimensionless viscosity group which is the ratio between the
viscosity of the injection well and the grid block, \( N_u = \frac{\mu_{\text{well}}}{\mu_{\text{gridblock}}} \). From the definitions of \( N_u \) and \( n \), we can see Eq. (7-1) represents the case in which the minimum viscosity is attained in the formation and (7-2) represents the case in which the minimum viscosity is not attained. The value of \( n \) and the equations to calculate foam viscosities were discussed in Chapter 6.

By using this model, the injection rate will then be a function of this apparent skin factor due to non-Newtonian effects. We can get higher injection rate because of this non-Newtonian effect (From our hypothetical field simulations, with this non-Newtonian effect, we found that the injectivity is greater by a factor of about 3~4 than if the non-Newtonian effect was not included). The modifications of the simulator were made in the “well” subroutine in UTCHEM and the modified codes are given in the appendix.

### 7.3 Hypothetical hydrogen sparging in aquifer

#### 7.3.1 Description of a hypothetical aquifer

A field application of hydrogen biosparging was performed at Cape Canaveral Air Station Florida by Newell et al. [2001]. Results from their eighteen-month low-volume pulsed hydrogen biosparging pilot test showed extensive biological dechlorination in a
30x30 ft zone located 15 to 20 ft below the water table in a sandy aquifer. In this case, hydrogen was injected about 20 ft below the water table and a 5 ft vadose zone existed above the water table. In the surfactant/foam process in Hill Air Force Base, the depth of the aquifer below the water table was also about 20 ft, but the vadose above the water table was thicker, of order 20 ft. Air was also injected from the bottom. So, just for comparison convenience, we will also take our hypothetical aquifer to be 20 ft under water table and set the vadose zone to be 5 feet in depth above it. Hydrogen will
also be injected into the aquifer from the bottom. Figure 7.8 shows the side view of the hypothetical aquifer. Figure 7.9 shows the top view of the hypothetical aquifer. The blue circles there are the pattern of injection wells. Injection will be for only one well at a time. From the figure we can see the injected gas flow should be symmetric for each injection well. So, we can just take one quarter of the adjacent area (the region in dash line in Figure 7.9) around an injection well and simulate the gas flow in this region. Figure 7.10 shows the scale of the simulated region, which is 25x25 ft in the horizontal cross section. In the simulation, the four vertical boundaries (B1, B2, B3, B4) are closed. But since the scale of the simulated area is quite large (25x25 ft), before gas breakthrough, gas can always flow towards the B1 and B2 boundaries in the simulations. Simulations will show that larger well spacing is possible with hydrogen-foam than with hydrogen sparging without foam. And with the wider well spacing, one can still completely remediate the entire aquifer between the wells, especially the base which is poorly contacted in conventional biosparging.
Just as we discussed earlier, in a field application, the injection pressure should be high enough to generate strong foam. A high injection pressure can provide enough driving force to distribute hydrogen horizontally along the bottom of the aquifer and the generated strong foam can also benefit the lateral flow of hydrogen. Taking the depth of the hypothetical aquifer to be 25 ft (including the vadose zone), the highest possible injection pressure will be about 17.5 psi, which is about 8.8 psi over the hydrostatic pressure. If the injection pressure is higher than 17.5 psi, it is possible that the sand in the aquifer would be fluidized and the wells or formation of the aquifer damaged. To be conservative, here we will take 8 psi over hydrostatic as our operation injection pressure. We will use this injection pressure in our following simulations. The allowable injection pressure would be even greater if we had assumed a thicker vadose zone as at Hill AFB.

7.3.2 Case studies of two different aquifer formations

Two different hypothetical aquifer formations are investigated. The first one is a homogeneous sand aquifer with a permeability of 40 darcy. The second one is a heterogeneous sand aquifer with two layers of high perm sand in its lower part. The high perm layers are 1 ft in thickness and have a permeability of 200 darcy. One is 1.5 ft above the bottom, the other 4.5 ft above the bottom. The rest of the aquifer is 40 darcy sand. The side views of these two aquifers are shown in Figure 7.11.
Figure 7.11 Side views of the two hypothetical aquifers

7.3.2.1 40 darcy homogeneous sand aquifer

A natural aquifer always has some heterogeneity, but it is always useful for us to start from a homogeneous case and make some basic comparisons and conclusions. The first and most important thing we are interested is the spacing of the injection wells. We are expecting to get larger well spacing and at the same time contact all the bottom of the aquifer by using foam. Since hydrogen is explosive when mixed with air, it is important to ensure that no hydrogen is leaked into the atmosphere during the sparging process. We must stop the injection as soon as hydrogen breaks through from
Figure 7.12 Gas saturation contour plots for with and without foam cases, homogeneous aquifer, injection pressure 8 psi over hydrostatic pressure.

the top of the aquifer. So our comparisons will be based on simulated results up to the breakthrough time of hydrogen.
Figure 7.12A shows gas saturation contour plots along the diagonal cross section of the simulated aquifer when foam is present. The gas flow is symmetric around an injection well so we just simulated one quarter of the total region. From the simulation we found that at the time of hydrogen breakthrough, the farthest distance along the diagonal direction reached by hydrogen was about 12.5 ft, as shown by the red line in Figure 7.12A. Within this 12.5 ft, the injected hydrogen can contact almost all the bottom of the aquifer and most of the lower half of the aquifer. If we convert this diagonal distance into well spacing distance, the optimum well spacing will be about 18 ft. Figure 7.12B shows the simulated results when there is no foam in the aquifer. From the comparison of Figures 7.12A and 7.12B we can see the difference between no foam and foam results. For hydrogen biosparging without foam, the injected hydrogen flows upwards and breaks through from the top very quickly. The area contacted by gas is smaller than in the foam case. At the time when hydrogen breaks through, the farthest distance along the diagonal direction reached by hydrogen is only about 7.5 ft. So if one wants to contact all of the aquifer without using foam, the needed well spacing will be about 10 ft, a factor of 1.8 smaller than that when foam is present.

Also, from the plots we can see that hydrogen saturation in the foam case is substantially larger than in the absence of foam, especially in the bottom 5 ft. In the foam case, hydrogen breaks through to the top of the aquifer after about 14,200 liters of hydrogen have been injected. When there is no foam, only about 1,840 liters of hydrogen can be injected before it breaks through to the top. So by the time of
hydrogen breakthrough, the average saturation of hydrogen in foam case is about 8 times larger than in the without foam case. This high hydrogen saturation is a beneficial factor to the bioremediation process, i.e., more contaminant can be degraded because of the presence of more trapped hydrogen.

Figure 7.13 shows the simulated injection rate for the field application when foam is present. From the simulation, it takes about 10 hours for the injected hydrogen to break through to the top of the aquifer. The injection rate is decreasing and levels off to steady state after about 1 hour of injection. At steady state the injection rate is around 20 LPM. Figure 7.14 shows the hydrogen injection rate when there is no foam. Hydrogen breaks through to the top after only 10 mins of injection. The injection rate
Figure 7.14 Homogeneous case, Gas injection rate, without foam in the aquifer. Constant injection pressure, 8 psi over hydrostatic pressure.

is much higher than in the foam case, increasing to about 250 LPM when hydrogen breaks through to the top of the aquifer.

7.3.2.2 40 darcy and 200 darcy heterogeneous sand aquifer

The second case investigated is a hypothetical heterogeneous aquifer. Though foam can reduce the mobility of gas in both of the high permeability and low permeability regions of porous media, it has the potential of selectively reducing the mobility more in higher permeability layers in contact with lower permeability layers. The most common explanation for this is the snap-off mechanism of foam [Falls et al., 1988; Ransohoff and Radke, 1988; Tanzil, 2001]. When gas flows from a low permeability
region to a high permeability region and encounters a lower capillary pressure, more lamellae will be generated due to the effect of snap-off. As a result, gas is hindered from flowing upward into the high permeability region. In our simulations this effect is accounted for in an approximate manner by increasing the apparent viscosity of gas in the high permeability region. Because of this effect of heterogeneity, we expect to have larger well spacing and better contact efficiency in the heterogeneous aquifer than in the homogeneous aquifer. As in the study of the homogeneous case, the maximum possible spacing of the injection wells when foam is present is investigated by simulations. Again, the time when hydrogen breaks through to the top of the aquifer is taken as the basis for the comparison.

Figure 7.15A shows the simulated gas saturation contour plots along the diagonal cross section of the aquifer when foam is present. Again, because of the symmetry of the injection flow, only a quarter of the total region around the injection well was simulated. In this heterogeneous case, the farthest distance along the diagonal direction reached by foam is about 20 ft. Hydrogen contacted almost all of the lower half of the aquifer within this 20 ft range. If we convert this distance into well spacing, the well spacing for this heterogeneous aquifer when foam is present will be about 29 ft. Compared to the homogeneous case, the well spacing we can have in this heterogeneous aquifer is larger by a factor of 1.6. Figure 7.15B shows the simulated results when there is no foam in the heterogeneous aquifer. Just as in the homogeneous case, the injected hydrogen breaks through to the top very fast. With the 8 psi over hydrostatic injection
Cross section gas saturation contour plots:

A: With Foam

B: Without Foam

Figure 7.15 Gas saturation contour plots for with and without foam cases, heterogeneous aquifer, injection pressure 8 psi over hydrostatic pressure

pressure, the farthest distance along the diagonal cross section contacted by gas is only
about 7.5 ft, which corresponds to a well spacing of about 11 ft. The well spacing when foam is present is more than 2.5 times larger.

By comparing Figure 7.15B with Figure 7.12B, which is the result without foam in the homogeneous case, we can find that the gas sweep distance in the bottom of the aquifer is similar in these two cases. Both of them are around 7.5 ft along the diagonal cross section of the aquifer. However, heterogeneity has a relatively favorable effect in the higher part of the aquifer where the high permeability sand exists. Gas in the heterogeneous case can flow as far as 12 ft along the diagonal cross section. In the homogeneous case, the farthest distance contacted by gas is still only about 7.5 ft.

In the heterogeneous case, the hydrogen saturation when foam is present is also much larger than without foam. With foam the lower half of the aquifer has a high hydrogen saturation and the injected hydrogen breaks through to the top after about 24,400 liters of hydrogen injected. When there is no foam, only about 2,120 liters of hydrogen can be injected before breakthrough – more than an order of magnitude lower.

Figure 7.16 shows the hydrogen injection rate when foam is present. Hydrogen breaks through to the top of the aquifer after about 24,400 liters injected in a total injection time of about 15 hours. The injection rate levels off and reaches its steady state after about 1 hour injection and stays around 25 LPM until breakthrough. Compared to the steady state simulated injection rate of 20 LPM in the homogeneous case (Figure 7.13),
the rate in the heterogeneous case is a little bit higher. Without foam, hydrogen breakthrough to the top occurs after about 10 mins injection and only about 2,120
liters of hydrogen injected (Figure 7.17). The injection rate when there is no foam is also much higher than in the foam case. It increases very fast and reaches about 270 LPM at the time when hydrogen breaks through, which is about 11 times larger than the rate we get in the foam case.

7.4 Discussion and summary

We can make a rough comparison here with the results of hydrogen biosparging test in the Cape Canaveral aquifer. Based on slug test results for 15 shallow monitoring wells, the average permeability of the aquifer was estimated to be about 34 darcy, which is very close to the 40 darcy sand we used in our simulations. The depth of the aquifer under the water table is about 20 ft, while above the water table a 5 ft high vadose zone exists. The injection pressure there was about 10 psi over hydrostatic pressure which is also close to the injection pressure of 8 psi over hydrostatic that we chose in our hypothetical design. So we can roughly compare our simulated results with the Cape Canaveral results and see the benefits of foam. Figure 7.18 shows the hydrogen distribution plot after hydrogen sparging without foam at Cape Canaveral. The numbers in this plot are dissolved gas concentrations. Newell et al [2000] found that each sparge point appeared to deliver hydrogen within a 5 ft radius of the sparge point, which means that the well spacing without foam should be about 10 ft. This result is consistent with our homogeneous case simulation results where we also found that the best well spacing when foam is not present is about 10 ft (Figure 7.12B). Also, from
Figure 7.18 Hydrogen sparging result from Cape Canaveral aquifer

Figure 7.18 we see that much of the bottom of the aquifer was not contacted by the injected gas, and the dissolved gas concentration is very low there. Compared to our 40 darcy homogenous foam case study (Figure 7.12A, where we can contact the whole bottom of the aquifer using a well spacing of about 18 ft and obtain a high trapped gas saturation), it is very clear that foam can make a big improvement in the application of hydrogen biosparging.

In this chapter, we investigated several conditions which need to be known before a field hydrogen foam application. Also, we investigated two hypothetical aquifers and estimated the foam effect on well spacing using simulation. We can get the following conclusions:
1. The threshold surfactant concentration for the surfactant mixture we are testing is about 0.02%. When the surfactant concentration is below this value, hydrogen injection is not able to generate strong foam (compared to foam generated from 0.1% (wt) surfactant solution).

2. To get the same result as in a surfactant filled aquifer, the minimum surfactant amount needed is about 0.2 PV. The number of 0.2 PV is obtained from our 2x2x2 ft tank which is a cube with a dimension of the depth of the sand pack. So in a field scale, when scaling up, the criteria to choose the 0.2 PV will be based on the volume of a cube which has a dimension of the depth of the aquifer, i.e. 20x20x20 ft in our hypothetical aquifer since the depth of it is 20 ft. (In the hypothetical simulations in this chapter, the injected PV is 0.2 PV of 25x25x20 ft, which is slightly larger than 0.2 PV of 20x20x20 ft.)

3. For the surfactant mixture we are testing, when the pressure gradient is higher than some threshold value, the simulation parameters will remain the same and not change with the increasing of pressure gradient. Also, in a field application, high injection pressure is desirable to get satisfactory performance.

4. For a 40 darcy homogeneous aquifer 25 ft deep with the water table 5 ft lower than the ground surface, the optimum well spacing is about 18 ft when hydrogen is injected from the bottom to generate foam. When there is some heterogeneity (two layers of 200 darcy sand in the lower part of the aquifer), the optimum well spacing increases to about 29 ft. This phenomenon shows that the heterogeneities in aquifers can help the transport and distribution of the injected hydrogen.
5. Foam can delay the breakthrough time of hydrogen and thus increase the average gas saturation in the aquifer. When there is no foam, hydrogen breaks through to the top after only about 1,900 liters hydrogen injection for both the homogeneous and heterogeneous cases. But when foam is present, one can inject much more hydrogen without breaking through to the top. For the homogeneous case, about 8 times more hydrogen can be injected before breakthrough and for the heterogeneous case, it is greater than 10 times more.
CONCLUSIONS AND RECOMMENDATIONS

In this dissertation, the properties of 3-D foam flow in porous media are studied and discussed. The foamabilities of several surfactant systems were screened. 2-D and 3-D foam experiments were performed to demonstrate the effect of foam on enhancement of gas/hydrogen sparging. A foam simulation model was proposed to simulate 3-D foam flow by using parameters from 1-D column experiments. Reservoir simulator UTCHEM was modified to incorporate this foam model. A hypothetical field foam application was designed with the help of the modified simulator and using the criteria obtained from the 3-D tank experiments.

8.1 Conclusions

The 1-D column surfactant screening experiments showed that, among all the surfactants tested (Neodol 25-7, Tween80, Aerosol MA80, AOS14-16, CS230, CS330, C12-3PO, C14-4PO and C13-4PO), the mixture of C13-4PO and CS330 (1:1) has the strongest foamability in the presence of the nutrient solution. For this surfactant mixture, there exists an optimum fraction (which is between 0.4~0.6) of C13-4PO in
the total surfactant concentration. The strongest foam can be obtained if these two surfactants are mixed in this range.

The 3-D foam experiments demonstrated that, under similar experimental condition, the mobility of foam in a 3-D tank is greater than that in a 1-D column. They also showed that foam can greatly increases lateral gas distribution along the bottom of the tank and the overall average gas saturation for both homogeneous and heterogeneous packings with the effects being significantly larger in the latter case. The generated foam is stable. Gas saturation in the tank remains almost the same 20 days after the stopping of gas flow. The experimental results represent an advance in understanding of foam flow in 3-D. They indicate that foam is a promising method for delivering hydrogen to aquifers to enhance anaerobic biodegradation.

The reservoir simulator UTCHEM was modified for foam flow. The foam parameters were measured in 1-D sand columns and the simulator was modified to match the 1-D and 3-D experiments. The model changes the gas relative permeability curve to account for the increased trapped gas saturation. It also uses an apparent gas viscosity which is a function of gas saturation, gas velocity and flow dimension. A geometric factor is defined to represent the mobility difference between 1-D and 3-D foam. It is the only parameter which cannot be measured in 1-D, and its value was found to be about 0.21 (in 1-D its value is 1.0). The proposed model successfully history matched the homogeneous and heterogeneous 3-D sand tank experimental results for total gas
saturation, gas injection rate, gas distribution and pressure profile along the tank diagonal 6 inches from the bottom.

The simulator along with additional 1-D foam experiments were used to design a hypothetical foam field application. The threshold total surfactant concentration to generate strong foam was found to be 0.02\% (wt) (compared to 0.1\% (wt) injected surfactant solution). A successful field application should satisfy this concentration requirement. Also, the simulation studies on two hypothetical aquifer formations (one is homogeneous and the other is heterogeneous) indicated that foam can greatly increase the optimum injection well spacing, in either homogeneous or heterogeneous formation. The optimum well spacing was larger in the heterogeneous aquifer where the transport and distribution of the injected hydrogen were increased because of the heterogeneities present, i.e., high permeability layers.

8.2 Recommendations for future work

More 3-D experiments are needed to investigate more of the flow properties of foam. Experiments using different surfactant systems or different kinds of sand which have different permeability are useful for us to understand more about the properties of 3-D foam. Also, more heterogeneous formations should be tested besides the particular heterogeneity we chose. It can give us a systemic understanding of how the heterogeneity affects the flow of foam.
For the simulation part, the conclusion that $F_g=0.21$ in 3-D foam flow was drawn from history match simulation of the current experimental results. For the phenomena we observed from our experiments (the mobility of 3-D foam is greater than 1-D), there is still lack of a comprehensive explanation for it. Qualitatively, one explanation may be that in 3-D the flowing gas can find more flowing paths than in 1-D and so gas mobility is higher in 3-D. But more efforts, either experimentally or theoretically, are needed to make this explanation quantitatively. A foam model which can reveal the mechanism of the relationship between 1-D and 3-D foam flow is desirable.

Also, in the heterogeneous system, to history match the experimental results, besides choosing the $F_g$ value to be equal to 0.21, we need to increase the $C_{\mu f}$ value to be about 3 times larger than the value obtained from 1-D column (Table 6.4). Here we assumed the $F_g$ value keeps the same in the heterogeneous system and adjusted $C_{\mu f}$ value to get the best history match simulation results. Our explanation is that the $C_{\mu f}$ value is increased due to the snap-off effect along the boundary of high and low permeability boundaries. The explanation is reasonable but there may still have some other possibilities. For example, it is possible that in the heterogeneous system, both of the $F_g$ value and the $C_{\mu f}$ are changed due to the heterogeneity effect. More experiments and simulations are needed to investigate the foam flow behavior in heterogeneous systems.
REFERENCES


Derjaguin, B.V.; Kussakov, M.M. Acta Physicochim. URSS 1939, 10(1), 25-44.


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Appendix A

Modified "UTOFOAM" subroutine

SUBROUTINE UTOFOAM

PURPOSE: REDUCE GAS-PHASE RELATIVE PERMEABILITY WHEN FOAM IS
PRESENT

CALL : NON

IMPLICIT DOUBLE PRECISION (A-H,O-Z)

INCLUDE 'PARAM.INC'

PARAMETER (MBX=NNX*NNY*NNZ)
PARAMETER (MBXW=MBX+MBW)

COMMON /DATEAD/ ZERO, ONE, ONEM, ONEM4, ONEM5, ONEM6, ONEM7, ONEM8, ONEM9
& ONEM10, ONEM12, ONEM15, ONEM50, ONEM52, ONEM55, ONEM58, ONEM59

* PIE, FIP8

COMMON /DEB1/ VBM(MBX), CSION(MBXW), TSURF(MBXW), PSURF(MBXW, MBX)
COMMON/FOAM1/EPXLO, SOSTAR, CSTAR, SWSTAR(MBX), SHRTN(MBXW),
* VELGR(MBXW), RFMAX(MBXW), SGRMX(MBXW), AGMX(MBXW), RFATT(MBXW),
* VELG(MBXW), VELG1(MBXW), HIYSTG(MBXW)

COMMON /GAS1/ P4MW(MBX), E4W(MBX), S4RC, P4RC, E4C, T44, S4RW(MBX)
* SGI, IGAS, NPHAS

COMMON /H1/ CTOT(MBXW, MXC), C(MBXW, MXC, MXP), CSE(MBXW), S(MBXW, MBX)
* CE(MBX, MXC, MXP)

COMMON /H3/ XIPT1(MBXW), XIPT2(MBXW), ALPHAM, BETA, LJK1, NP,
* NPAS(MBXW)

COMMON /H6/ VISM(MBX, MXP), RPERS(MBX, MXP), PERMX(MBX), PERMY(MBX),
* PERMZ(MBX), Q1(MXW, MXP), QB(MXW, MXBW), Q1(MXW, MXBW), Q1(MXW, MXBW),
* CUMOQ(MXW), CUMPG(MXW), PIW(MXW)

COMMON /H11/ DT, CURANT, NMX1, NX, NY, NZ, NMXNY, NBLN, NBLW, N
COMMON /H2/ TRKX(MBX, MXP), TRKY(MBX, MXP), TRKZ(MBX, MXP), TX(MBX),
* TY(MBX), TZ(MBX), CONVX(MBX, MXC, MXP), CONVY(MBX, MXC, MXP),
* Conv2(MBX, MXC, MXP), VELX(MBX, MXP), VELY(MBX, MXP), VELZ(MBX, MXP)

COMMON /REST/ CUNI(MXC), CUMP(MXC), O1P(MXC), O1P(MXC), T, TINJ, WHPV
* FRP, ICNT, IINJ, INEC, IRST

COMMON /WKSPL/ SWET(MBXW), FACTS(MBXW), WSPL5(MBXW)

parameter (EPSCS=0.00002)

IGAS: FLAG FOR FOAM MODEL SELECTION (IGAS=2)
SWSTAR: MINIMUM AQUEOUS-PHASE SATURATION FOR FOAM TO EXIST
OR LIMITING WATER SATURATION FOR "FIXED PC" MODEL
THIS IS A FUNCTION OF PERM.
SOSTAR: MAXIMUM OIL-PHASE SATURATION FOR FOAM TO EXIST
CSTAR: MINIMUM SURFACANT CONCENTRATION FOR FOAM TO EXIST
RFMAX: MAX. FACTOR BY WHICH FOAM CAN REDUCE GAS MOBILITY
EOPXLO: THE RANGE IN WATER SATURATION OVER WHICH FOAM COLLAPSES
SHRTN: A PARAMETER FOR SHARE-THINNING BEHAVIOUR OF FOAM
RFATT: RESISTANT FACTOR OF FOAMS
VELGR: GAS VELOCITY AT THE REF. PERM. (FT/DAY)

INITIALIZE ARRAYS

IF (ICNT.LE.1) THEN
    DO I1 = 1, NBL


199
RFACT(I) = 1.0

CONTINUE
ENDIF

C
*FIXED PC** MODEL :IGAS =2

C
DO 2 I = 1,NBL
    SWET(I) = S(I,1)
    j=1
    IF (S(I,1).LE.PRCSN) then
        SWET(I) = S(I,3)
        j=3
    endif
    FACTS(I) = 0.0
    SWT(i)=min(swet(i),one)
    Swet(i)=max(zero,swet(i))
    2 CONTINUE

C effect of gas saturation

IF (IGAS.GT.1) THEN
    DO 10 I = 1,NBL

        IF (TSURF(I).LE.(CSTAR-epsco).OR.S(I,2).GT.SOSTAR) THEN
            RFAC(I) = 1
        ELSEIF (SWET(I).LT.(SOSTAR-I)-EPXLO) THEN
            RFAC(I) = 1
        ELSEIF (SWET(I).GE.(SOSTAR-I)-EPXLO).AND.
            & (SWET(I).LE.(SOSTAR-I)+EPXLO) THEN
            RFAC(I) = 1+(RFMAX(I)-1)*(SWET(I)-SOSTAR(I)+EPXLO)
            & /EPXLO/2
        ELSE
            IF (Swet(i).ge.(1.0-Sgm(i))) then
                RFAC(I)=RFMAX(i) * ((1-SWET(I))/sgm(i))**sgmexp(i)
            elseif((RFMAX(i)-1).LT.1e-3) RFAC(I)=1.0
            elseif((Swet(i).LT.1.0-Sgm(i)).AND.
                & (Swet(i).GT.(SOSTAR(I)+EPXLO))) then
                RFAC(I)=RFMAX(i)
            endif
        endif
    10 CONTINUE
ENDIF

C
EFFECT OF GAS VELOCITY, AND SHEAR THINNING

C
DO 20 I = 1,NBL
    VELG(I) = SQRT(VELX(I,NPHAS)**2+VELY(I,NPHAS)**2)*
        +VELZ(I,NPHAS)**2

    20 CONTINUE

DO 40 I = 1,NBL
    IF(VELG(i).GT.VELGR(i)) then
        FACTS(I)=max(onem12, (VELG(I)/VELGR(i)))**((SHRTN(I)-1))
    else
        facts(i)=1.0
    endif
    RFACT(I) = RFAC(I)*FACTS(I)
rfact(i) = max(one,rfact(i))
40 CONTINUE

Ceffect of surfactant concentration

do 42 i = 1,nbl
   if (tsurf(i).gt.(cstar-epsca)) then
      if (tsurf(i).gt.(cstar-epsca)) then
         facts(i) = 1.0
      else
         facts(i) = ((tsurf(i)-cstar-epsca)/(2*epsca))
      endif
   endif
   rfact(i) = rfact(i)**facts(i)
   rfact(i) = max(one,rfact(i))
   rfact(i) = min(rfact(i),1000000000.0)
42 continue

C
CREDUCE GAS RELATIVE PERMEABILITY
C
DO 50 I = 1,NBL
   RPERM(I,NPHAS) = RPERM(I,NPHAS)/RFACT(I)

CHere just modified the rperm for simplicity
Creaders can always change to modify the gas viscosity as the following
Ccode shows, the results will be the same. 0.02: gas viscosity without foam
Cvis(i,nphas)=0.02*rfact(i)

50 CONTINUE
C
RETURN
END
Appendix B

Modified "TRAPG" subroutine

SUBROUTINE TRAPG

-- PURPOSE: CALCULATES CAPILLARY NO., RESIDUAL SAT., RELATIVE PERMEABILITY AND CAPILLARY PRESSURE WHEN GAS PHASE IS PRESENT IN ADDITION TO OIL/WATER/MET Phases

CALL: NONE

--

IMPLICIT DOUBLE PRECISION (A-H,O-Z)

INCLUDE 'PARAM.INC'

PARAMETER (NXB=NNX*NNY*NNZ)
PARAMETER (NXBW=NXB+NXW)
PARAMETER (pctol=1e-6)

LOGICAL LWSKP1
COMMON /COMPRC/ PR(NXB), FOLD(NXB), PERC(NXB), CORPP(NXB), CORPF(NXB)
COMMON /DATAD/ ZERO, ONE, ONEX, ONEX4, ONEK5, ONEM5, ONEW7, ONEM9, ONEM10, ONEM12, ONEP12, ONEM50, ONEP50, ONEM5M, PONEM, ONE199, PCRSM
* , PIE, FL8
COMMON /DEB1/ VBN(NXB), CSION(NXB), TSURF(NXB), PSURF(NXBW, NXW)
COMMON /DILV/ DDZ(NXB), WKS4(NXB), WKS5(NXBW), WKS6(NXBW),
* WKS7(NXBW), WKS8(NXBW), WKS9(NXBW), WKS10(NXBW),
* WKS11(NXBW)

C added by dicken
common /dpv/ DPVINJ
COMMON /FOAM/ FOAM, FOAMT, FOAMX, FOAMY, SWSTAR, WSHRM, SHRTN(NXBW),
* VELGR(NXBW), RMAX(NXB), SGM(NXBW), SGEXP(NXBW), RFAC(NXBW),
* VELG(NXBW), S40D(NXBW), IHYSTG(NXBW),
common /busheng/ RP40D(NXBW), RPTIME(NXBW)

COMMON /WELL1/ NWELL, IRO, IDW(NXBW), IFLAG(NXBW), IDIR(NXBW),
* ICU(NXBW, NXBW), JVC(NXBW, NXBW), JAC(NXBW, NXBW), NWBC(NXBW)
COMMON /HH10/ EL(NXB), DX(NNX), DY(NNY), DZ(NNZ), R(NNX), RP(NNX),
* RP3(NNX), IJLP3S(NNX, NNY, NNZ), IPRESS

COMMON /GA51/ P4RW(NXBW), E4W(NXBW), S4RC, P4RC, E4C, T44, S4RW(NXBW)
* , SGI, IGS, NPHASE
COMMON /GA52/ V1S4, VSLOP, X1FTG, X1FTGW, S2RW4(NXBW), S2RC4, S1R1(NXBW)
* , SR2(NXB)
COMMON /HH1/ CTOT(NXBW, NXC), C(NXBW, NXC, NXP), CSE(NXBW, SXBNW, MXW)
* , CE(NXBW, MXC, MXP)
COMMON /HH2/ C2PLC, C2PRC, B1, B2, B3, F1, F2, F11, F12, G11, G12, G13, D12, G22, G23,
* XIFW, CSEL(NXBW), CSEU(NXBW), CHUH, AHUH, IFT, IHAND
COMMON /HH3/ X1FT1(NXBW), X1FT2(NXBW), ALPHA, BETA, IJK1, NP,
* NPHASE(NXBW)
COMMON /HH4/ V5S(NXBW, MXW), RPERM(NXBW, MXP), PERMX(NXBW), PERMY(NXBW),
* PERMZ(NXBW), QI(NXBW, MXP), Q(NXBW, MXW, MXP), QT(NXBW),
* CUMQI(NXBW), CUMQW(NXBW, PFW(NXW)
COMMON /HH5/ S1RW(NXBW), S2RW(NXBW), T11, T22, T33, P1RW(NXBW), P2RW(NXBW)
* , P3RW(NXBW), E1W(NXBW), E2W(NXBW), E3W(NXBW), P1RC, P2RC, P3RC, S3RW(NXBW)
* , CNUM(NXBW, MXP), S1RC, S2RC, S3RC, E13C, E23C, E31C, SR(NXBW, MXP), ITRAP
* , IPERM
COMMON /HH6/ DT, CURANT, NXM1, NX, NY, NZ, NXNY, NBL, NBLW, N

202
C

do 5 i = 1,nbl
    swet(i)=s(i,1)
    if (s(i,1).le.prcessn) swet(i) = s(i,3)
    swet(i)=min(swet(i),one)
    swet(i)=max(zero,swet(i))
    if (ihystg(i).eq.0) then
        if (s(i,4).gt.gastol.and.(s4old(i)-s(i,4)).gt.3*dpvinj)
            ihystg(i)=1
        else if (ihystg(i).eq.1) then
            if (s(i,4).gt.gastol.and.
                (s(i,4)-s4old(i)).gt.10*dpvinj)
                ihystg(i)=0
    endif
    if ((tsurf(i).ge.cstar).and.(swet(i).ge.swstar(i))).and.
        ihystg(i).eq.1) then
        wksp97(i)=sgrf(i)-s4rw(i)
    else
        wksp97(i)=0.0
    endif
  5 continue

do 20 l = 1,mphas
  do 10 i = 1,nbl
    prc(i,l) = 0.0
    sr(i,l) = 0.0
  10 continue

do 30 i = 1,nbl
  s4old(i)=s(i,mphas)
  if (s4old(i).gt.zero.and.s4old(i).lt.gastol) then
    s(i,1)=s(i,1)/(1.0-s4old(i))
    s(i,2)=s(i,2)/(1.0-s4old(i))
    s(i,3)=s(i,3)/(1.0-s4old(i))
    s(i,4)=zero
  endif
  sr1(i) = 0.0
  sr2(i) = 0.0
  srg(i) = 0.0
  cnum2(i) = 0.0
203
IF (NPHASE(I),EQ.1) THEN
  P(I,2) = P(I,1)
P(I,3) = P(I,1)
P(I,NPHAS) = P(I,1)
ENDIF
if (igas.ne.2) then
  conf=10.0**(-xiftw)
  conf2=10.0**xiftg
  pcr(i,nphas) = conf*cpcwgpormy(i)*sqrt(corfpi)**conf2
  p(i,nphas) = p(i,1)+pcr(i,nphas)
endif
30 CONTINUE

C TYPE II(+) BRINE/MICROEMULSION FLOW W/O GAS

C DO 180 I = 1,NBL
  IF (TSURF(I).LT.EPSME.OR.NPHASE(I).EQ.3.OR.(CSE(I).LT.CSEU(I)
     ZERO)) THEN
    WKSP1(I) = 0.0
  ELSE
    WKSP1(I) = 1.0
  ENDIF
180 CONTINUE

C CALL WHENEQ (NBL,WKSP1,1,ONE,LL,IEND)
C IF (IEND.EQ.0) GO TO 270
DO 190 I = 1,IEND
SR(LL(I),1) = MIN(S(LL(I),1),S1RW(LL(I)))
SR(LL(I),3) = MIN(S(LL(I),3),S3RW(LL(I)))
SR(LL(I),NPHAS) = MIN(S(LL(I),NPHAS),S4RW(LL(I)))
WKSP3(I) = P1RW(LL(I))
WKSP4(I) = P3RW(LL(I))
WKSP7(I) = P4RW(LL(I))
WKSP5(I) = E1W(LL(I))
WKSP6(I) = E3W(LL(I))
WKSP9(I) = E4W(LL(I))
WKSP8(I) = XIFT1(LL(I))
WKSP8(I) = 10.0**WKSP8(I)
190 CONTINUE

C CDIRS IVDEP

C BRINE PHASE RESIDUAL SATURATION

C IF (ITRAP.EQ.1) THEN
DO 200 I = 1,IEND
  WKSP9(I) = CNUM(LL(I),1)
  IF (ABS(WKSP9(I)).GE.PRCSN) THEN
    WKSP9(I) = WKSP9(I)/WKSP8(I)
    WKSP1(I) = S1RC+(S1RW(LL(I))-S1RC)/(1.+T11*WKSP9(I))
  ENDIF
  CNUM(LL(I),1) = WKSP9(I)
200 CONTINUE

DO 210 I = 1,IEND
  WKSP1(I) = MIN(S1RW(LL(I)),WKSP1(I))
  WKSP1(I) = MAX(ZERO,WKSP1(I))
  WKSP7(I) = S(LL(I),1)
  WKSP1(I) = MIN(WKSP7(I),WKSP1(I))
  SR(LL(I),1) = WKSP1(I)
210 CONTINUE

C CDIRS IVDEP
MICROEMULSION RESIDUAL SATURATION

DO 230 I = 1, IEND
   WKSP9(I) = CNUM(LL(I), 3)
   IF (ABS(WKSP9(I)) .GE. PRCSN) THEN
      WKSP9(I) = WKSP9(I) / WKSP8(I)
      WKSP2(I) = S3RC + (S3RM(LL(I)) - S3RC)/(1. + T33 * WKSP9(I))
   ENDIF
   CNUM(LL(I), 3) = WKSP9(I)
230 CONTINUE

DO 240 I = 1, IEND
   WKSP2(I) = MIN(S3RW(LL(I)), WKSP2(I))
   WKSP9(I) = S(LL(I), 3)
   WKSP2(I) = MIN(WKSP9(I), WKSP2(I))
   SR(LL(I), 3) = WKSP2(I)
240 CONTINUE

CDIR$ IVDEP

GAS PHASE RESIDUAL SATURATION

CONF1 = 10.0**XIFI$GW

DO 244 I = 1, IEND
   WKSP9(I) = CNUM(LL(I), NPHAS)
   IF (ABS(WKSP9(I)) .GE. PRCSN) THEN
      WKSP9(I) = WKSP9(I) / CONF1
      WKSP11(I) = S4RC + (S4RW(LL(I)) - S4RC)/(1. + T44 * WKSP9(I))
   ENDIF
   CNUM(LL(I), NPHAS) = WKSP9(I)
244 CONTINUE

DO 246 I = 1, IEND
   WKSP11(I) = MIN(S4RW(LL(I)), WKSP11(I))
   WKSP11(I) = MAX(ZERO, WKSP11(I))
   WKSP9(I) = S(LL(I), NPHAS)
   WKSP11(I) = MIN(WKSP9(I), WKSP11(I))
   SR(LL(I), NPHAS) = WKSP11(I)
246 CONTINUE

END POINT RELATIVE PERMEABILITIES & CURVATURES

DO 250 I = 1, IEND
   WKSP3(I) = P1RW(LL(I)) + (S3RW(LL(I)) - SR(LL(I), 3)) * (P1RC -
   P1RW(LL(I))) / (S3RW(LL(I)) - S3RC)
   WKSP4(I) = P3RW(LL(I)) + (S1RW(LL(I)) - SR(LL(I), 1)) * (P3RC -
   P3RW(LL(I))) / (S1RW(LL(I)) - S1RC)
   WKSP7(I) = P4RW(LL(I)) + (S1RW(LL(I)) - SR(LL(I), 1)) * (P4RC -
   P4RW(LL(I))) / (S1RW(LL(I)) - S1RC)
   WKSP5(I) = E1W(LL(I)) + (S3RW(LL(I)) - SR(LL(I), 3)) * (E13C -
   E1W(LL(I))) / (S3RW(LL(I)) - S3RC)
   WKSP6(I) = E3W(LL(I)) + (S1RW(LL(I)) - SR(LL(I), 1)) * (E31C -
   E3W(LL(I))) / (S1RW(LL(I)) - S1RC)
   WKSP9(I) = E4W(LL(I)) + (S1RW(LL(I)) - SR(LL(I), 1)) * (E43C -
   E4W(LL(I))) / (S1RW(LL(I)) - S1RC)
   IF (ABS(WKSP5(I)) .LE. PRCSN) WKSP5(I) = ONEM6
   IF (ABS(WKSP6(I)) .LE. PRCSN) WKSP6(I) = ONEM6
   IF (ABS(WKSP9(I)) .LE. PRCSN) WKSP9(I) = ONEM6
250 CONTINUE

ENDIF

DO 252 I = 1, IEND
   SNORM = 1.0 - SR(LL(I), 1) - SR(LL(I), 3) - SR(LL(I), NPHAS)
   SNORM = 1.0 - SR(LL(I), 1) - SR(LL(I), 3) - SR(LL(I), NPHAS)
WKSP1(I) = (S(LL(I),1)-SR(LL(I),1))/SNORM
WKSP1(I) = MAX(ZERO,WKSP1(I))
WKSP1(I) = MIN(ONE,WKSP1(I))
WKSP2(I) = (S(LL(I),3)-SR(LL(I),3))/SNORM
WKSP2(I) = MAX(ZERO,WKSP2(I))
WKSP2(I) = MIN(ONE,WKSP2(I))
WKSP10(I) = (S(LL(I),NPHAS)-SR(LL(I),NPHAS))/SNORM
WKSP10(I) = MAX(ZERO,WKSP10(I))
WKSP10(I) = MIN(ONE,WKSP10(I))

252 CONTINUE
C
C RELATIVE PERMEABILITIES AND CAPILLARY PRESSURE FOR TYPE II(*)
C
CONF = 10.0**(-XIPTW)
C
CDIR$ IVDEP
C
CONF1 = 10.0**XIPTG
DO 260 I = 1,IEND
C * IF (WKSP1(I).GT.PRCSN) RPERM(LL(I),1) = WKSP3(I)*(WKSP1(I)
C * **WKSP5(I))
C * IF (WKSP2(I).GT.PRCSN) RPERM(LL(I),3) = WKSP4(I)*(WKSP2(I)
C * **WKSP6(I))
C * IF (WKSP10(I).GT.PRCSN) RPERM(LL(I),NPHAS) = WKSP7(I)*
C * (WKSP10(I)**WKSP9(I))
C
**************************************************************************

IF (WKSP1(I).GT.PRCSN) RPERM(LL(I),1) =
  *((s(ll(i),1)-sr(ll(i),1))/(1-sr(ll(i),1)))**WKSP5(I)
IF (WKSP2(I).GT.PRCSN) RPERM(LL(I),3) =
  *((s(ll(i),3)-sr(ll(i),3))/(1-sr(ll(i),3)))**WKSP6(I)
IF (WKSP10(I).GT.PRCSN) RPERM(LL(I),NPHAS) =
  *((s(ll(i),nphas)-sr(ll(i)))/(1-sr(ll(i))))**WKSP9(I)
**************************************************************************

RPERM(LL(I),2) = 0.0
C
conf: 1 / oil water interfacial tension
conf1: water gas interfacial tension
pORMY(LL(I))*SRT(CORFP(LL(I)))): sqrt(#/k)
wksps is the interfacial tension between microemulsion and oil
 CPC(LL(i),1) is CPC in the input file
epc(LL(i),1) is EPC in the input file
WKSP19(I) = CONF*CPC(LL(I),1)*PORMY(LL(I))*SRT(CORFP(LL(I))))
PRC(LL(I),3) = WKSP19(I)*WKSP8(I)*(1.0-WKSP1(I))**EPC(LL(I),1)
P(LL(I),3) = PRC(LL(I),3)+P(LL(I),1)
if (igas.eq.2) then
  PRC(LL(I),NPHAS) = WKSP19(I)*CONF1*(1.0-WKSP1(I))**EPC(LL(I),1)
else
  j = ll(i)
  WKSP1(i) = (1.-s(j,nphas)-sr(j,1)-sr(j,3)) /
  (1.-sr(j,1)-sr(j,3))
  WKSP1(I) = MAX(pctol,WKSP1(I))
  WKSP1(I) = MIN(ONE,WKSP1(I))
  prc(i,nphas) = conf*cpcw*pormy(j)*srt(corfp(j))
  *conf1*WSKPL(i)**epcwg
endif
P(LL(I),NPHAS) = PRC(LL(I),NPHAS)+P(LL(I),1)

260 CONTINUE
C
C TYPE II(-) OIL/MICROEMULSION FLOW W/O GAS used in foam simu

206
270 DO 280 I = 1,NBL
  IF (TSURF(I).LT.EPSME.OR.NPHASE(I).EQ.3.OR.CSE(I).GE.CSEU(I)
    & .OR.(NPHASE(I).EQ.1 AND S(I,NPHAS).LE.ZERO)) THEN
    WKSP1(I) = 0.0
  ELSE
    WKSP1(I) = 1.0
  ENDIF
280 CONTINUE
CALL WHENEQ (NBL,WKSP1,1,ONE,LL,IEND)
IF (IEND.EQ.0) GO TO 370
DO 290 I = 1,IEND
  SR1(LL(I)) = MIN(S(LL(I),2),S2RW(LL(I)))
  IF there is no oil, then oil residual saturation equals to zero.
  SR2(LL(I)) = MIN(S(LL(I),2),S2RW4(LL(I)))
  SR(LL(I),3) = MIN(S(LL(I),3),S3RW(LL(I)))
  SR(LL(I),NPHAS) = MIN(S(LL(I),NPHAS),S4RW(LL(I)))
  Srg(LL(I))=MIN(S(LL(I),NPHAS),S4RW(LL(I)))+WKSP97(LL(I))
  WKSP2(I) = P4RW(LL(I))
  WKSP3(I) = P3RW(LL(I))
  WKSP4(I) = P2RW(LL(I))
  WKSP5(I) = E3W(LL(I))
  WKSP6(I) = E2W(LL(I))
  WKSP7(I) = E4W(LL(I))
290 CONTINUE

C CDIR$ IVDEP
C RESIDUAL OIL SATURATION TO MICROEMULSION
C IF (ITRAP.EQ.1) THEN
  DO 300 I = 1,IEND
    WKSP7(I) = CNUM(LL(I),2)
    WKSP8(I) = XIFT2(LL(I))
    WKSP8(I) = 10.0**WKSP8(I)
    IF (ABS(WKSP7(I)) .GE. PRCSN) THEN
      WKSP7(I) = WKSP7(I)/WKSP8(I)
      WKSP1(I) = S2RC+(S2RW(LL(I))-S2RC)/(1.0+T22*WKSP7(I))
    ENDIF
  CNUM(LL(I),2) = WKSP7(I)
300 CONTINUE
DO 310 I = 1,IEND
  WKSP1(I) = MIN(S2RW(LL(I)),WKSP1(I))
  WKSP2(I) = MAX(ZERO,WKSP1(I))
  WKSP7(I) = S(LL(I),2)
  WKSP1(I) = MIN(WKSP7(I),WKSP1(I))
  SR1(LL(I)) = WKSP1(I)
310 CONTINUE

C CDIR$ IVDEP
C RESIDUAL OIL SATURATION TO GAS
C CONF2 = 10.0**XIPTG
DO 314 I = 1,IEND
  WKSP7(I) = CNUM(LL(I),2)
  IF (ABS(WKSP7(I)) .GE. PRCSN) THEN
    WKSP7(I) = WKSP7(I)/CONF2
    WKSP1(I) = S2RC+(S2RW(LL(I))-S2RC)/(1.0+T22*WKSP7(I))
  ENDIF
  CNUM2(LL(I)) = WKSP7(I)
314 CONTINUE
DO 316 I = 1,IEND
WKSP1(I) = MIN(S2RW4(LL(I)),WKSP1(I))
WKSP1(I) = MAX(ZERO,WKSP1(I))
WKSP7(I) = S(LL(I),2)
WKSP1(I) = MIN(WKSP7(I),WKSP1(I))
SR2(LL(I)) = WKSP1(I)

316    CONTINUE

C
CDIR$ IVDEP
C
MICROEMULSION RESIDUAL SATURATION

DO 330 I = 1,IEND
WKSP7(I) = CNUM(LL(I),3)
IF (ABS(WKSP7(I)).GE.PRCSN) THEN
  WKSP7(I) = WKSP7(I)/WKSP8(I)
  WKSP2(I) = S3RC+(S3RW(LL(I))-S3RC)/(1.+T33*WKSP7(I))
ENDIF
CNUM(LL(I),3) = WKSP7(I)

330    CONTINUE

DO 340 I = 1,IEND
WKSP2(I) = MIN(S3RW(LL(I)),WKSP2(I))
WKSP2(I) = MAX(ZERO,WKSP2(I))
WKSP7(I) = S(LL(I),3)
WKSP2(I) = MIN(WKSP7(I),WKSP2(I))
SR(LL(I),3) = WKSP2(I)

340    CONTINUE

C
CDIR$ IVDEP
C
RESIDUAL GAS SATURATION

CONF2 = 10.**XIPTG

DO 344 I = 1,IEND
WKSP7(I) = CNUM(LL(I),NPHAS)
IF (ABS(WKSP7(I)).GE.PRCSN) THEN
  WKSP7(I) = WKSP7(I)/CONF2
  WKSP2(I) = S4RC-(S4RW(LL(I))-S4RC)/(1.+T44*WKSP7(I))
  srg(ll(i)) = wksp2(i)+wksp97(ll(i))
ENDIF
CNUM(LL(I),NPHAS) = WKSP7(I)

344    CONTINUE

DO 346 I = 1,IEND
WKSP2(I) = MIN(S4RW(LL(I)),WKSP2(I))
WKSP2(I) = MAX(ZERO,WKSP2(I))
WKSP7(I) = S(LL(I),NPHAS)
WKSP2(I) = MIN(WKSP7(I),WKSP2(I))
SR(LL(I),NPHAS) = WKSP2(I)
  srg(llll(i)) = MIN(S4RW(LL(I))+wksp97(ll(i)),srg(lll(i)))
  srg(lll(i)) = MAX(ZERO,srg(lll(i)))
  srg(ll(i)) = MIN(WKSP7(I),srg(ll(i)))

346    CONTINUE

C
END POINT RELATIVE PERMEABILITIES & CURVATURES

DO 350 I = 1,IEND
WKSP2(I) = P4RW(LL(I))+(S2RW4(LL(I))-SR2(LL(I)))*(P4RC-
P4RW(LL(I)))/(S2RW4(LL(I))-S2RC4)
WKSP3(I) = P3RW(LL(I))+(S2RW(LL(I))-SR1(LL(I)))*(P3RC-
P3RW(LL(I)))/(S2RW(LL(I))-S2RC)
WKSP4(I) = P2RW(LL(I))+(S3RW(LL(I))-SR(LL(I),3))*(P2RC-
P2RW(LL(I)))/(S3RW(LL(I))-S3RC)
WKSP5(I) = E3W(LL(I))+(S2RW(LL(I))-SR1(LL(I)))*(E31C-
E3W(LL(I)))/(S2RW(LL(I))-S2RC)

208
WKSP6(I) = E2W(LL(I)) + (S3RW(LL(I)) - SR(LL(I),3))*(E23C-
* E2W(LL(I)))/(S3RW(LL(I)) - S3RC)
WKSP7(I) = E4W(LL(I)) + (S2RW4(LL(I)) - SR2(LL(I)))*(E4C-
* E4W(LL(I)))/(S2RW4(LL(I)) - S2RC4)
IF (ABS(WKSP5(I)) .LE. PRCSN) WKSP5(I) = ONE65
IF (ABS(WKSP6(I)) .LE. PRCSN) WKSP6(I) = ONE65
IF (ABS(WKSP7(I)) .LE. PRCSN) WKSP7(I) = ONE65
ENDIF

NORMALIZE SATURATIONS FOR MICROEMULSION AND GAS PHASES

DO 352 I = 1, IEND
WKSP1(I) = (S(L(L(I),3) - SR(L(L(I),3)))/(1.0 - SR(L(L(I),3)) -
* SR(L(L(I),NPHAS) - SR1(L(L(I))))
WKSP1(I) = MAX(ZERO, WKSP1(I))
WKSP1(I) = MIN(ONE, WKSP1(I))
WKSP9(I) = (S(L(L(I),NPHAS) - SR3(L(L(I))))/(1.0 - SR3(L(L(I)) -
* SR(L(L(I),2)) - SR2(L(L(I))))
WKSP9(I) = MAX(ZERO, WKSP9(I))
WKSP9(I) = MIN(ONE, WKSP9(I))
END DO

NORMALIZE OIL SATURATION, USE FAHEY'S EQUATION TO CALCULATE
THREE PHASE OIL RESIDUAL SATURATION

DO 354 I = 1, IEND
SNORM = 1.0 - SR(L(L(I),3) - SR2(L(L(I))
SR(L(L(I),2) = SR1(L(L(I)))*(1.0 - S(L(L(I),NPHAS))/SNORM + SR2(L(L(I)) -
* S(L(L(I),NPHAS))/SNORM
IF (S(L(L(I),3) .LE. PRCSN) SR(L(L(I),2) = SR2(L(L(I))
IF (SR(L(L(I),2) .LE. ZERO) SR(L(L(I),2) = 0.0
IF (SR(L(L(I),2)) .GT. S(L(L(I),2)) SR(L(L(I),2) = S(L(L(I),2)
WKSP10(I) = (S(L(L(I),2) - SR(L(L(I),2)))/(1.0 - SR(L(L(I),3) -
* SR(L(L(I),NPHAS) - SR(L(L(I),2))
WKSP10(I) = MAX(ZERO, WKSP10(I))
WKSP10(I) = MIN(ONE, WKSP10(I))
END DO

RELATIVE PERMEABILITIES FOR TYPE II(-) W/O GAS
CDIR$ IVEP

DO 360 I = 1, IEND
IF (WKSP1(I) .GT. PRCSN) RPERM(LL(I),3) = WKSP3(I)*WKSP1(I)
**WKSP5(I)
IF (WKSP9(I) .GT. PRCSN) RPERM(LL(I),NPHAS) = WKSP2(I)*WKSP9(I)
**WKSP7(I)
IF (WKSP10(I) .GT. PRCSN) RPERM(LL(I),2) = WKSP4(I)*WKSP10(I)
**WKSP6(I)

**Modified code: ******************************************************************************************************
IF (WKSP1(I) .GT. PRCSN) RPERM(LL(I),3) =
* ((S(L(L(I),3) - SR(L(L(I),3)))/(1 - SR(L(L(I),3))))**WKSP5(I)
IF (WKSP9(I) .GT. PRCSN) RPERM(LL(I),NPHAS) =
* ((S(L(L(I),NPHAS) - SR3(L(L(I))))/(1 - SR3(L(L(I)))))**WKSP7(I)
IF (WKSP10(I) .GT. PRCSN) RPERM(LL(I),2) =
* ((S(L(L(I),2) - SR(L(L(I),2)))/(1 - SR(L(L(I),2))))**WKSP6(I)

RPERM(LL(I),1) = 0.0
END DO

CAPILLARY PRESSURE
CONF = 10.0**(-XIFTW)

C
CDIR$ IVDEP
C
CONF$ = 10.0**XIFTG
DO 362 I = 1, IEND
   WKSP8(I) = XIFT2(LL(I))
   WKSP8(I) = 10.0**WKSP8(I)
   WKSP1(I) = (S(LL(I),3)-SR(LL(I),3))/(1.-SR(LL(I),3)-
   * SR(LL(I),2)-SR(LL(I),NPHAS))
   WKSP1(I) = MAX(ZERO,WKSP1(I))
   WKSP1(I) = MIN(ONE,WKSP1(I))
   WKSP2(I) = S(LL(I),2)-SR(LL(I),2)
   WKSP3(I) = S(LL(I),NPHAS)-SR(LL(I),NPHAS)
   WKSP19(I) = CPC(LL(I),1)*PORMY(LL(I))*SRT(CORFP(LL(I))))
   PRC(LL(I),2) = CONF*WKSP19(I)*WKSP8(I)*(1.0-WKSP1(I))
   **EPC(LL(I),1)
   P(LL(I),2) = PRC(LL(I),2)+P(LL(I),1)
   if (igas.eq.2) then
      PRC(LL(I),NPHAS) = CONF*WKSP19(I)*CONF2*(1.-WKSP1(I))
   **EPC(LL(I),1)
   else
      j = ll(1)
      wksp1(i) = (1.-s(j,nphas)-sr2(j)-sr(j,3))/
      * (1.-sr2(j)-sr(j,3))
      WKSP1(I) = MAX(pctol,WKSP1(I))
      WKSP1(I) = MIN(ONE,WKSP1(I))
      proc(j,nphas) = conf*pcpwy*pormy(j)*sqrt(corfp(j))
      * conf2*wksp1(i)**epcwy
   endif
   P(LL(I),NPHAS) = PRC(LL(I),NPHAS)+P(LL(I),1)
362 CONTINUE

C For foam case ccccccccccccccccccccc
C consider the production wells, add a 0.05 more capillary entry pressure for gas
C to flow into the screen of the wells, this is just for the 3-D tank.

if(igas.gt.2) then
   DO 1010 M = 1,NWELL
      ID = IDW(N)
   DO 5050 IWB = 1,NWBC(ID)
      IJK = IJKPOS(ID,IWB),JWC(ID,IWB),KWC(ID,IWB)
      if(iflag(id).eq.2.or.iflag(id).eq.4) then
         do i=1,lend
            if (ijk.eq.ll(i)) then
               proc(ijk,nphas)=proc(ijk,nphas)+0.05
               p(ijk,nphas)=proc(ijk,nphas)+p(ijk,1)
            endif
         enddo
      endif
   5050 continue
1010 continue
Endif

C
C NO SURFACTANT (WATER/OIL TWO PHASE FLOW) W/O GAS OR
C THREE PHASE FLOW (WATER/OIL/MICROEMULSION) W/O GAS
C
370 DO 380 I = 1,NBL
EPSME.AND.NPHASE(I).NE.3)) THEN
  WKSP1(I) = 0.0
ELSE
  WKSP1(I) = 1.0
ENDIF

380 CONTINUE
CALL WHENEQ (NBL,WKSP1,1,CNE,LL,IEND)
IF (IEND.EQ.0) GO TO 650
DO 390 I = 1,IEND
  SR(LL(I),1) = MIN(S(LL(I),1),S1RW(LL(I)))
  SR1(LL(I)) = MIN(S(LL(I),2),S2RW(LL(I)))
  SR(LL(I),NPHAS) = MIN(S(LL(I),NPHAS),S4RW(LL(I)))
  SR2(LL(I)) = MIN(S(LL(I),2),S2RW(LL(I)))
  Srg(ll(i)) = MIN(S(LL(I),NPHAS),S4RW(LL(I)))+wksp97(ll(i))
  WKSP3(I) = P1RW(LL(I))
  WKSP4(I) = P2RW(LL(I))
  WKSP18(I) = P4RW(LL(I))
  WKSP5(I) = E1W(LL(I))
  WKSP6(I) = E2W(LL(I))
  WKSP19(I) = E4W(LL(I))
390 CONTINUE

CDIR$ IVDEP
C CAPILLARY NUMBER AND RESIDUAL SATURATION FOR WATER
C
IF (ITRAP.EQ.1) THEN
  DO 400 I = 1,IEND
    WKSP9(I) = CNUM(LL(I),1)
    WKSP8(I) = 10.0**XIFT1(LL(I))
    IF (ABS(WKSP9(I)).GE.PRCSN) THEN
      WKSP9(I) = WKSP9(I)/WKSP8(I)
      WKSP1(I) = S1RC+(S1RW(LL(I)))-S1RC)/(1.+T11*WKSP9(I))
    ENDIF
    CNUM(LL(I),1) = WKSP9(I)
  400 CONTINUE
DO 410 I = 1,IEND
  WKSP1(I) = MIN(S1RW(LL(I)),WKSP1(I))
  WKSP1(I) = MAX(ZERO,WKSP1(I))
  WKSP7(I) = S(LL(I),1)
  WKSP1(I) = MIN(WKSP7(I),WKSP1(I))
  SR(LL(I),1) = WKSP1(I)
410 CONTINUE

CDIR$ IVDEP
C CAPILLARY NUMBER AND RESIDUAL SATURATION FOR OIL TO WATER
C
DO 414 I = 1,IEND
  WKSP9(I) = CNUM(LL(I),2)
  WKSP3(I) = 10.0**XIFT2(LL(I))
  IF (ABS(WKSP9(I)).GE.PRCSN) THEN
    WKSP9(I) = WKSP9(I)/WKSP3(I)
    WKSP2(I) = S2RC+(S2RW(LL(I)))-S2RC)/(1.+T22*WKSP9(I))
  ENDIF
  CNUM(LL(I),2) = WKSP9(I)
414 CONTINUE
DO 416 I = 1,IEND
  WKSP2(I) = MIN(S2RW(LL(I)),WKSP2(I))
  WKSP2(I) = MAX(ZERO,WKSP2(I))
  WKSP9(I) = S(LL(I),2)
  WKSP2(I) = MIN(WKSP9(I),WKSP2(I))
SR1(LL(I)) = WKSP2(I)

416 CONTINUE

C  
C CDIR$ IVDEP  
C CAPILLARY NUMBER AND RESIDUAL SATURATION FOR GAS  
C  
C CONF1 = 10.**XIPTGW  
DO 422 I = 1,IEND  
   WKSP9(I) = CNUM(LL(I),2)  
   IF (ABS(WKSP9(I)) .GE. PRCSN) THEN  
      WKSP9(I) = WKSP9(I)/CONF1  
      WKSP2(I) = S4RC*(S4RW(LL(I)) - S4RC)/(1.+T44*WKSP9(I))  
      SRG(LL(I)) = wksp2(i)+wksp97(ll(i))  
   ENDIF  
   CNUM(LL(I),NPHAS) = WKSP9(I)  
422 CONTINUE  

DO 424 I = 1,IEND  
   WKSP2(I) = MIN(S4RW(LL(I)),WKSP2(I))  
   WKSP9(I) = S(LL(I),NPHAS)  
   WKSP2(I) = MIN(WKSP9(I),WKSP2(I))  
   SR(LL(I),NPHAS) = WKSP2(I)  
   SRG(LL(I)) = MIN(S4RW(LL(I)) - wksp97(ll(i)),SRG(LL(I)))  
   SRG(LL(I)) = MAX(ZERO,SRG(LL(I)))  
   SRG(LL(I)) = MIN(WKSP9(I),SRG(LL(I)))  
424 CONTINUE

C  
C CDIR$ IVDEP  
C CAPILLARY NUMBER AND RESIDUAL SATURATION FOR OIL TO GAS  
C  
C CONF2 = 10.**XIPTG  
DO 432 I = 1,IEND  
   WKSP9(I) = CNUM(LL(I),NPHAS)  
   IF (ABS(WKSP9(I)) .GE. PRCSN) THEN  
      WKSP9(I) = WKSP9(I)/CONF2  
      WKSP2(I) = S2RC*(S2RW4(LL(I)) - S2RC)/(1.+T22*WKSP9(I))  
   ENDIF  
432 CONTINUE

DO 434 I = 1,IEND  
   WKSP2(I) = MIN(S2RW4(LL(I)),WKSP2(I))  
   WKSP9(I) = S(LL(I),2)  
   WKSP2(I) = MIN(WKSP9(I),WKSP2(I))  
   SR2(LL(I)) = WKSP2(I)  
434 CONTINUE

C  
C END POINT RELATIVE PERMEABILITIES & CURVATURES  
C  
DO 450 I = 1,IEND  
   C sr1 is oil residual saturation to water, if there is no oil, sr1 will be zero  
   C***************SR1(LL(I)) = MIN(S(LL(I),2),S2RW(LL(I))))***************  
   WKSP3(I) = P1RW(LL(I))+(S2RW(LL(I)) - SR1(LL(I)))*(P1RC-  
      P1RW(LL(I)))/(S2RW(LL(I)) - S2RC)  
   WKSP4(I) = P2RW(LL(I))+(SLRW(LL(I)) - SR(LL(I),1)))*(P2RC-  
      P2RW(LL(I)))/(SLRW(LL(I)) - S1RC)  
   C see line 589, if there is no oil, then oil residual saturation equals to zero.  
   C************SR2(LL(I)) = MIN(S(LL(I),2),S2RW4(LL(I))))*************  
   C********** S2RC4 is zero in this code.  
   WKSP18(I) = P4RW(LL(I))+(S2RW4(LL(I)) - SR2(LL(I)))))*(P4RC-  
      P4RW(LL(I)))/(S2RW4(LL(I)) - S2RC4)  
   WKSP5(I) = E1W(LL(I))+(S2RW(LL(I)) - SR1(LL(I))))*(E13C-
* 
WKSP6(I) = E2W(LL(I)) + (S1RW(LL(I)) - SR(LL(I),1)) * (E23C - 
E2W(LL(I)))/(S1RW(LL(I)) - S1RC)

IF (ABS(WKSP5(I)) .LE. PRCSN) WKSP5(I) = CNEM6
IF (ABS(WKSP6(I)) .LE. PRCSN) WKSP6(I) = CNEM6
IF (ABS(WKSP19(I)) .LE. PRCSN) WKSP19(I) = CNEM6

450 CONTINUE
ENDIF
C
C NORMALIZE SATURATIONS FOR WATER AND GAS PHASES
C
DO 452 I = 1,IEND
C srl is oil residual saturation to water, if there is no oil, srl will be zero
C*************************************************************************
WKSP1(I) = 1.0 - SR(LL(I),1) - SR(LL(I),NPHAS)
WKSP7(I) = (S(LL(I),1) - SR(LL(I),1))/(WKSP1(I) - SR1(LL(I)))
WKSP7(I) = MAX(ZERO,WKSP7(I))
WKSP7(I) = MIN(ONE,WKSP7(I))
WKSP8(I) = (S(LL(I),NPHAS) - SRG(LL(I)))/(1.0 - SR(LL(I),1) -
* SRG(LL(I)))
WKSP8(I) = MAX(ZERO,WKSP8(I))
WKSP8(I) = MIN(ONE,WKSP8(I))

452 CONTINUE
C
C NORMALIZE OIL SATURATION, USE FAYER'S EQUATION TO CALCULATE
C THREE PHASE OIL RESIDUAL SATURATION
C
DO 454 I = 1,IEND
SNORM = 1.0 - SR(LL(I),1) - SR2(LL(I))
SR(LL(I),2) = SR1(LL(I))*((1.0 - S(LL(I),NPHAS))/SNORM) - SR2(LL(I))
* S(LL(I),NPHAS)/SNORM
IF (S(LL(I),1).LE.PRCSN) SR(LL(I),2) = SR2(LL(I))
IF (SR(LL(I),2).LE.PRCSN) SR(LL(I),2) = 0.0
IF (SR(LL(I),2).LT.SR(LL(I),2)) SR(LL(I),2) = S(LL(I),2)
WKSP10(I) = (S(LL(I),2) - SR(LL(I),2))/(WKSP1(I) - SR(LL(I),2))
WKSP10(I) = MAX(ZERO,WKSP10(I))
WKSP10(I) = MIN(ONE,WKSP10(I))

454 CONTINUE
C
C RELATIVE PERMEABILITIES FOR OIL/WATER AND W/O GAS
C
CDIR$ IVDEP
C
DO 456 I = 1,IEND
C
IF (WKSP7(I).GT.PRCSN) RPERM(LL(I),1) = WKSP3(I)*WKSP7(I)
**WKSP5(I)
C
IF (WKSP8(I).GT.PRCSN) RPERM(LL(I),NPHAS) = WKSP18(I)*WKSP8(I)
**WKSP9(I)
C
IF (WKSP10(I).GT.PRCSN) RPERM(LL(I),2) = WKSP4(I)*WKSP10(I)
**WKSP6(I)
C*************************************************************************

xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx
IF (WKSP7(I).GT.PRCSN) RPERM(LL(I),1) = 
* ((S(LL(I),1) - SRG(LL(I),1))/((1.0 - SRG(LL(I),1))))**WKSP5(I)
IF (WKSP8(I).GT.PRCSN) RPERM(LL(I),NPHAS) = 
* ((S(LL(I),NPHAS) - SRG(LL(I),1))/((1.0 - SRG(LL(I),1))))**WKSP9(I)
IF (WKSP10(I).GT.PRCSN) RPERM(LL(I),2) = 
* ((S(LL(I),2) - SRG(LL(I),2))/((1.0 - SRG(LL(I),2))))**WKSP6(I)
C*************************************************************************

RPERM(LL(I),3) = 0.0
456 CONTINUE
CAPILLARY PRESSURE

CONF = 10.0**(-XIFTW)

CDIR$ IVDEP

CONF1 = 10.0**XIFTGW

DO 460 I = 1, IEND

WKSP8(I) = 10.0**XIFTI(LL(I))

WKSP9(I) = CONF*CPC(LL(I),1)**PORMY(LL(I))*SRT(CORFP(LL(I)))

WKSP1(I) = (S(LL(I),1)-SR(LL(I),1))/(WKSP1(I)-SR(LL(I),2))

WKSP1(I) = MIN(ZERO, WKSP1(I))

P(LL(I),2) = WKSP1(I)**EFC(LL(I),1)

P(LL(I),2) = PRC(LL(I),2) + P(LL(I),1)

if (igas.eq.2) then

PRC(LL(I),NPHAS) = WKSP9(I)*CONF1*(1.0-WKSP1(I))

**EFC(LL(I),1)

else

j = ll(i)

wksp1(i) = (1.-s(j,nphas)-sr2(j)-sr(j,1)) /

(1.-sr2(j)-sr(j,1))

WKSP1(I) = MAX(pctol, WKSP1(I))

WKSP1(I) = MIN(ZERO, WKSP1(I))

PRC(j,nphas) = conf*cpcwg*pormy(j)*sqrt(corfp(j))

* conf1*wksp1(i)**epcwg

endif

P(LL(I),NPHAS) = PRC(LL(I),NPHAS) + P(LL(I),1)

460 CONTINUE

c For air/water case cccccc cccc cccc cccc cccc cccc

c consider the production wells, add a 0.05 more capillary entry pressure for gas
to flow

c into the screen of the wells, this is just for the 3-D tank.

if(igas.gt.2) then

DO 1011 M = 1, NWELL

ID = IDW(M)

DO 5051 IWB = 1, NWBC(ID)

IJK = IJKPOS(IDC,ID,WB), JWC(IDC,ID,WB), KWC(IDC,ID,WB)

if(iflag(id).eq.2.or.iflag(id).eq.4) then

do i=1,end

if (ijk.eq.ll(i)) then

PRC(IJK,NPHAS) = PRC(IJK,NPHAS) + 0.05

P(IJK,NPHAS) = PRC(IJK,NPHAS) + P(IJK,1)

endif

enddo

5051 continue

1011 continue
endif

THREE PHASE REGION W/O GAS PHASE

END POINT RELATIVE PERMEABILITY, CURVATURE, AND
CAPILLARY NUMBER FOR MICROEMULSION

IBGN = 0
C

CDIR$ IVDEP
C

DO 470 I = 1, IEND
   IF (TSURF(LL(I)) .GE. EPSME.AND. NPHASE(LL(I)) .NE. 2) THEN
      WKSP1(I) = SR(LL(I),1)
      WKSP2(I) = SR1(LL(I))
      IBGN = IBGN+1
      LL2(IBGN) = LL(I)
      WKSP12(IBGN) = WKSP1(I)
      WKSP13(IBGN) = WKSP2(I)
   ENDIF
470 CONTINUE

IEND = IBGN

IF (IEND.EQ.0) GO TO 650
DO 480 I = 1, IEND
   LL(I) = LL2(I)
   WKSP1(I) = WKSP12(I)
   WKSP2(I) = WKSP13(I)
480 CONTINUE

C

CDIR$ IVDEP
C

DO 490 I = 1, IEND
   WKSP4(I) = P1RW(LL(I))
   WKSP5(I) = P2RW(LL(I))
   WKSP6(I) = P3RW(LL(I))
   WKSP7(I) = E1W(LL(I))
   WKSP8(I) = E2W(LL(I))
   WKSP9(I) = E3W(LL(I))
   WKSP13(I) = 10.0**XIPT1(LL(I))
   WKSP14(I) = 10.0**XIPT2(LL(I))
   SR(LL(I),3) = MIN(S(LL(I),3), S3RW(LL(I)))
490 CONTINUE

C

CDIR$ IVDEP
C

CAPILLARY NUMBER, ENDPOINT PERM. AND EXPONENT FOR
C
MICROEMULSION PHASE
C

IF (ITRAP.EQ.1) THEN
   DO 492 I = 1, IEND
      WKSP15(I) = CNUM(LL(I),3)
      IF (S(LL(I),1).LE.WKSP1(I).AND.S(LL(I),2).GT.WKSP2(I))
      * THEN
         WKSP6(I) = P3RW(LL(I))+(S2RW(LL(I))-SR1(LL(I)))*(P3RC-
         * P3RW(LL(I)))/(S2RW(LL(I))-S2RC)
         WKSP9(I) = E3W(LL(I))+(S2RW(LL(I))-SR1(LL(I)))*(E31C-
         * E3W(LL(I)))/(S2RW(LL(I))-S2RC)
         WKSP15(I) = WKSP15(I)/WKSP14(I)
      ELSE
         WKSP6(I) = P3RW(LL(I))+(S1RW(LL(I))-SR(LL(I),1)))*(P3RC-
         * P3RW(LL(I)))/(S1RW(LL(I))-S1RC)
         WKSP9(I) = E3W(LL(I))+(S1RW(LL(I))-SR(LL(I),1)))*(E31C-
         * E3W(LL(I)))/(S1RW(LL(I))-S1RC)
         WKSP15(I) = WKSP15(I)/WKSP13(I)
      ENDIF
   IF (ABS(WKSP9(I)).LE.PRCSN) WKSP9(I) = ONEM5
   CNUM(LL(I),3) = WKSP15(I)
492 CONTINUE

C

RESIDUAL SATURATION FOR MICROEMULSION PHASE
C
END POINT RELATIVE PERMEABILITIES & CURVATURES
C
DO 500 I = 1, IEND
WKSP3(I) = S3RC*(S3RW(LL(I)) - S3RC)/(1.0*T33*CNUM(LL(I), 3))
WKSP3(I) = MIN(S3RW(LL(I)), WKSP3(I))
WKSP3(I) = MAX(ZERO, WKSP3(I))
WKSP3(I) = MIN(S(LL(I), 3), WKSP3(I))
SR(LL(I), 3) = WKSP3(I)
* WKSP4(I) = P1RW(LL(I)) + (S3RW(LL(I)) - SR(LL(I), 3))*(P1RC - P1RW(LL(I)))/(S3RW(LL(I)) - S3RC)
* WKSP5(I) = P2RW(LL(I)) + (S3RW(LL(I)) - SR(LL(I), 3))*(P2RC - P2RW(LL(I)))/(S3RW(LL(I)) - S3RC)
* WKSP7(I) = E1W(LL(I)) + (S3RW(LL(I)) - SR(LL(I), 3))*(E13C - E1W(LL(I)))/(S3RW(LL(I)) - S3RC)
* WKSP8(I) = E2W(LL(I)) + (S3RW(LL(I)) - SR(LL(I), 3))*(E23C - E2W(LL(I)))/(S3RW(LL(I)) - S3RC)
IF (ABS(WKSP7(I)) .LE. PRCSN) WKSP7(I) = ONE6
IF (ABS(WKSP8(I)) .LE. PRCSN) WKSP8(I) = ONE6
500 CONTINUE
ENDIF
C NORM. SATURATIONS FOR OIL, WATER, MICROEMULSION, AND GAS
C
DO 510 I = 1, IEND
WKSP1(I) = 1.0 - SR(LL(I), 1) - SR(LL(I), 3) - SR(LL(I), NPHAS)
WKSP1(I) = (S(LL(I), NPHAS) - ARG(LL(I)))/(1.0 - SR(LL(I), 1) -
* SR(LL(I), 3) - ARG(LL(I)) - SR2(LL(I)))
WKSP1(I) = MAX(ZERO, WKSP1(I))
WKSP1(I) = MIN(ONE, WKSP1(I))
WKSP10(I) = (S(LL(I), 1) - SR(LL(I), 1))/WKSP3(I) - SR1(LL(I)))
WKSP10(I) = MAX(ZERO, WKSP10(I))
WKSP10(I) = MIN(ONE, WKSP10(I))
WKSP11(I) = (S(LL(I), 2) - SR(LL(I), 2))/WKSP3(I) - SR1(LL(I), 2))
WKSP11(I) = MAX(ZERO, WKSP11(I))
WKSP11(I) = MIN(ONE, WKSP11(I))
WKSP12(I) = (S(LL(I), 3) - SR(LL(I), 3))/WKSP3(I) - SR1(LL(I)))
WKSP12(I) = MAX(ZERO, WKSP12(I))
WKSP12(I) = MIN(ONE, WKSP12(I))
510 CONTINUE
C RELATIVE PERMEABILITIES
C
DO 520 I = 1, IEND
C IF (WKSP10(I).GT.PRCSN) RPERM(LL(I), 1) = WKSP4(I)*WKSP10(I)
C * **WKSP7(I)
C IF (WKSP11(I).GT.PRCSN) RPERM(LL(I), 2) = WKSP5(I)*WKSP11(I)
C * **WKSP8(I)
C IF (WKSP12(I).GT.PRCSN) RPERM(LL(I), 3) = WKSP6(I)*WKSP12(I)
C * **WKSP9(I)
C IF (WKSP1(I).GT.PRCSN) RPERM(LL(I), NPHAS) = WKSP18(I)*WKSP1(I)
C * **WKSP19(I)
C********************************************************************
C Modified codes. ******************************************************
C IF (WKSP10(I).GT.PRCSN) RPERM(LL(I), 1) =
* (((S(LL(I), 1) - SR(LL(I), 1))/1.0 - SR(LL(I), 1)))**WKSP7(I)
IF (WKSP11(I).GT.PRCSN) RPERM(LL(I), 2) =
* (((S(LL(I), 2) - SR(LL(I), 2))/1.0 - SR(LL(I), 2)))**WKSP8(I)
IF (WKSP12(I).GT.PRCSN) RPERM(LL(I), 3) =
* (((S(LL(I), 3) - SR(LL(I), 3))/1.0 - SR(LL(I), 3)))**WKSP9(I)
IF (WKSP1(I).GT.PRCSN) RPERM(LL(I), NPHAS) =
* (((S(LL(I), NPHAS) - ARG(LL(I))/1.0 - ARG(LL(I))))**WKSP19(I)
520 CONTINUE
CAPILLARY PRESSURE FOR THREE PHASE FLOW W/O GAS

CONF = 10.0**(-XIPTW)
DO 620 I = 1, IEND
   WKSP4(I) = WKSP3(I) - SR(LL(I),2)
   WKSP10(I) = (S(LL(I),1) - SR(LL(I),1)) / WKSP4(I)
   WKSP10(I) = MAX(ZERO, WKSP10(I))
   WKSP10(I) = MIN(ONE, WKSP10(I))
   WKSP19(I) = CPC(LL(I),1) * PORMY(LL(I)) * SQRT(CORFP(LL(I))))
   WKSP15(I) = CONF * WKSP19(I) * WKSP13(I) * (1.0 - WKSP10(I))
   **EPC(LL(I),1)
   P(LL(I),3) = WKSP15(I) + P(LL(I),1)
   PRC(LL(I),3) = WKSP15(I)
620 CONTINUE

CDIR$ IVDEP

DO 630 I = 1, IEND
   WKSP15(I) = 0.0
   IF ((WKSP11(I) + WKSP12(I)) .GT. ZERO) THEN
      WKSP19(I) = CPC(LL(I),1) * PORMY(LL(I)) * SQRT(CORFP(LL(I))))
      WKSP15(I) = CONF * WKSP19(I) * WKSP14(I) * (WKSP11(I) /
      (WKSP11(I) + WKSP12(I))) + EPC(LL(I),1)
   ENDIF
   P(LL(I),2) = P(LL(I),1) + WKSP15(I)
   PRC(LL(I),2) = P(LL(I),2) - P(LL(I),1)
630 CONTINUE

CDIR$ IVDEP

DO 632 I = 1, IEND
   WKSP4(I) = 10.0**XIPTG
   WKSP19(I) = CONF * CPC(LL(I),1) * PORMY(LL(I)) * SQRT(CORFP(LL(I))))
   IF (I(GAS.EQ.2)) THEN
      WKSP10(I) = WKSP19(I) * WKSP4(I) * (1.0 - WKSP10(I)) + EPC(LL(I),1)
   ELSE
      j = ll(i)
      WKSP10(I) = (1.0 - S(j,nphas) - SR(j,1) - SR(j,2) - SR(j,3)) /
      (1.0 - SR(j,1) - SR(j,2) - SR(j,3))
      WKSP10(I) = MAX(POCTOL, WKSP10(I))
      WKSP10(I) = MIN(ONE, WKSP10(I))
      WKSP4(I) = (conf * CPCW* PORMY(j) * SQRT(CORFP(j)))
      * WKSP4(I) + WKSP10(I)**EPGW
   ENDIF
   P(LL(I),NPHAS) = P(LL(I),1) + WKSP10(I)
   PRC(LL(I),NPHAS) = WKSP10(I)
632 CONTINUE
650 CONTINUE

SET RELATIVE PERMEABILITY TO UNITY FOR
GRID BLOCKS WITH SINGLE PHASE ONLY

DO 660 I = 1, NBBL
   IF (NPHASE(I) .EQ. 1 .AND. S(I,1) .GE. ONE) THEN
      RPERM(I,1) = 1.0
      RPERM(I,2) = 0.0
      RPERM(I,3) = 0.0
      RPERM(I,NPHAS) = 0.0
   ENDIF
660 CONTINUE

DO 670 I = 1, NBBL
   IF (NPHASE(I) .EQ. 1 .AND. S(I,2) .GE. ONE) THEN

RPERM(I,1) = 0.0
RPERM(I,2) = 1.0
RPERM(I,3) = 0.0
RPERM(I,NPHAS) = 0.0
ENDIF

670 CONTINUE
DO 680 I = 1,NBL
   IF (NPHASE(I) .EQ. 1 .AND. S(I,3) .GE. ONE) THEN
      RPERM(I,1) = 0.0
      RPERM(I,2) = 0.0
      RPERM(I,3) = 1.0
      RPERM(I,NPHAS) = 0.0
   ENDIF

680 CONTINUE
DO 690 I = 1,NBL
   IF (S(I,NPHAS) .GE. ONE) THEN
      RPERM(I,1) = 0.0
      RPERM(I,2) = 0.0
      RPERM(I,3) = 0.0
      RPERM(I,NPHAS) = 1.0
   ENDIF
   IF (S40ld(i) .gt. zero .AND. S40ld(i) .lt. gastol) THEN
      S(i,1) = S(i,1) *(1.0 - S40ld(i))
      S(i,2) = S(i,2) *(1.0 - S40ld(i))
      S(i,3) = S(i,3) *(1.0 - S40ld(i))
      S(i,4) = S40ld(i)
   ENDIF

690 CONTINUE

RETURN
END
Appendix C

Modified "WELL" subroutine

SUBROUTINE WELL

---------------------------------------------------------------------------------
PURPOSE : ALLOCATES RATES TO INDIVIDUAL LAYERS BASED ON THE
MOBILITY RATIO FOR THE RATE CONSTRAINT INJECTION WELLS
, IT ALSO IMPOSES WELL CONSTRAINTS FOR THE IMPLICIT
SOLUTION OF THE PRESSURE EQUATION.

CALL : NONE
---------------------------------------------------------------------------------

IMPLICIT DOUBLE PRECISION (A-H,O-Z)

INCLUDE 'PARAM.INC'

PARAMETER (MXB=NXN*NDY*NNZ)
PARAMETER (MBXN=MXB+MXP)
PARAMETER (MXX=NXN*NNZ)
PARAMETER (MAXNOB=MAXBIO-MAXBS+1)
PARAMETER (MAXSEQ=MAXBIO+MAXBS*(MAXNOB-3),
+ LENW=MAXSEQ*MAXSEQ+17*MAXSEQ+206,LENW=MAXSEQ+21)
LOGICAL LMO

COMMON /AREAS/ AREAXZ(MXZ),HXZ(MXZ),HZ(MXZ),HXL(NNZ),HZN(NNZ)
* ,HB(XN),HZB(NNZ)
COMMON /DATAD/ ZER0,ONE,ONEM,ONEM4,ONEM5,ONEM6,ONEM7,ONEM8,ONEM9
& ,ONEM10,ONEM12,ONEP12,ONEM50,ONEP50,ONEM55,ONEM61,ONEM99,PRCSN
& ,PIE,FIP8
COMMON /DENOIL/ DNOILC(MXC),DENBIO(MAXBIO)
COMMON /DLNRO/ DLX1(MX),BLX1(MX),ALY1(MX),BLY1(MX),ALZ1(MX),
* BLZ1(MX),RPERMX(MX,MXP),RPERMY(MX,MXP),RPERMZ(MX,MXP)
c
busheng
COMMON/FOAM/EPXLO,SOSTAR,CSTAR,wshear,SWSTAR(MXB),SRTHN(mxbw),
* VELGR(mxbw),rlmax(mxb),sgm(mxbw),sgexp(mxbw),rfact(mxbw),
* velg(mxbw),s4old(mxbw),ihystg(mxbw)

COMMON /GAS1/ P4RW(MXB),E4W(MXB),S4RC,P4RC,E4C,T44,S4RW(MXB)
* ,SGI,IGAS,NPHAS
COMMON /H11/ CTOT(MXBW,MXC),C(MXBW,MXC,MXP),CSE(MXBW),S(MXBW,MXP)
* ,CE(MXB,MXC,MXP)
COMMON /H5/ VIS(MXB,MXP),RPERMX(MXB,MXP),PERMX(MXB),PERMY(MXB),
* PERMZ(MXB),QX(MXW,MXP),QB(MXW,MXWB),Q(MXW,MXWB),QT(MXW),
* CUMQ(MXW),CUMQ(MXW),PWF(MXW)
COMMON /H60/ EL(MXB),EX(NNX),DY(NNY),DZ(NNZ),R(NNX),RP(NNX)
* ,RPSON(NNX,NNY,NNZ),IPRESS
COMMON /H11/ DT,CURANT,MBM1,NX,NY,NZ,MNN,NML,NDL,M
COMMON /H12/ DENC,NENZ,DEN23,DEN3,DEN7,DEN8,IDE
COMMON /H13/ DENC,MP,MXP,MPC(MXB,MXP)
COMMON /H14/ TPS(MXB),P(MXB,MXP),CPC(MXB,2),EP(MXB,2),
* SSTK(MXB),IOW
COMMON /H15/ TRSX(MXB,MXP),TRSY(MXB,MXP),TRSZ(MXB,MXP),TX(MXB),
* TY(MXB),TZ(MXB),CONVX(MXB,MXC,MXP),CONVY(MXB,MXC,MXP),
* CONVZ(MXB,MXC,MXP),VELX(MXB,MXP),VELY(MXB,MXP),VELZ(MXB,MXP)
COMMON /NEW1/ SPNAME(MXC),PWFR(MXW,MXWB),WELNAM(MXW,10),
* RUNNO(10)
COMMON /MULOL1/ MMOL1,NO,LMO
COMMON /MULPP5/ DNOME(MXN)

219
COMMON /REST/ CUMI(MXC), CUMP(MXC), OIP(MXC), OP(MXC), T, TINJ, WHPV,
* PRF, ICKT, IINJ, INEC, IRST
COMMON /SOMA/ DMAX, IDISP, ICF(MXC), ICOORD, ITC, IUNIT
COMMON /TEMGN/ DNX(MX2), DNZ(MX2)
COMMON /VKSP2/ AW(MXBN), AE(MXBN), AN(MXBN), AS(MXBN), AT(MXBN),
* AS(MXBN), AC(MXBN), BV(MXBN)
COMMON /WELL1/ NWELL, IRW, IRO, IDW(MXW), IFLAG(MXW), IDER(MXW),
* IWC(MXW, MXWB), JW(MXW, MXWB), JWC(MXW, MXWB), NWBC(MXW)
COMMON /WELL2/ RW(MXW), SWEW(MXW), XPRF(MXW, MXWB), IPRF(MXW),
* IW(MXW), JX(MXW), IFIRST(MXW), ILAST(MXW)
COMMON /WELL3/ RO(MXW, MXWB), PIB(MXW, MXWB), PI(MXW, MXWB, MXP),
* WELNDX(MXW, MXWB), HEAD(MXW, MXWB), PE(MXW), IShut(MXW)

cc busheng
common /temp/ cumpv
common /busheng/ WDX_gas(MXW, MXWB), velgas(mw, mxwb), spwell(mw)

cccccc
DIMENSION GAMMAL(MXP), GAMMAB(MXWB)
C
C add some codes here to include the non-newtonian injectivity model for GAS
phase
C wshear=1,(set in the input file),consider the model, otherwise, does not
C consider

IF (wshear.eq.1) then
  DO 1010 M = 1,NWELL
      ID = IDW(M)
  DO 5050 INB = 1,NWB(ID)
      IJK = IJPOS(IWC(ID, INB), JWC(ID, INB), NWBC(ID, INB))
  c consider only for injection wells
  if(iflag(id).eq.1.or.iflag(id).eq.3) then
  C considered different injection well directions

  if(idir(id).eq.1) then
      velgas(id, iwb) = q(id, iwb, nphas)/
      & (2*3.141593*rw(id)*dx(iwc(id, iwb)))
  elseif(idir(id).eq.2) then
      velgas(id, iwb) = q(id, iwb, nphas)/
      & (2*3.141593*rw(id)*dy(iwc(id, iwb)))
  else
      velgas(id, iwb) = q(id, iwb, nphas)/
      & (2*3.141593*rw(id)*dz(kwc(id, iwb)))
  endif

  velg(ijk) = sqrt(velx(ijk, nphas)**2+vely(ijk, nphas)**2
  *+velz(ijk, nphas)**2)

  if( (velgas(id, iwb).gt.velgr(ijk))
  & .and. (rfact(ijk).gt.one)
  * .and. (velg(ijk).gt.zero) ) then
    v_nu=(velgas(id, iwb)/velg(ijk))**(shrtn(ijk)-1)
    v=1/rfact(ijk)
    if (v_nu.le.v) then
      spwell(id)=1/(1-shrtn(ijk))*
      * (log( (v**v) * (v_nu)**(1-v) ) -v-1)
    else
      spwell(id)=1/(1-shrtn(ijk))*(log(v_nu)-v_nu+1)
    endif
    else
      spwell(id)=0
  endif

220
CONVF = 0.025149754
WDX_gas(ID,IWB) = (SQRT(PERM(IJK)*PERMY(IJK)))*
& DZ(KWC(ID,IWB)) 
& ( CONVF* ( LOG( RO(ID,IWB) ) + RW(ID) ) + SWELL(ID) + spwell(id) )

endif

5010 continue
1010 continue
endif

DO 10 M = 1,NWELL
  ID = IDW(M)
  QT(ID) = 0.0
DO 15 IWB = 1,NWBC(ID)
  IJK = IJXPOS(IWC(ID,IWB),JWC(ID,IWB),KWC(ID,IWB))
  PIB(ID,IWB) = 0.0
  QB(ID,IWB) = 0.0
  HEAD(ID,IWB) = 0.0
  PWFR(ID,IWB) = P(IJK,1)
DO 20 L = 1,NPHAS
  PI(ID,IWB,L) = 0.0
  Q(ID,IWB,L) = 0.0
  GAMMAL(L) = 0.0
20 CONTINUE
15 CONTINUE
10 CONTINUE
C CHECK FOR THE SHUT IN CONDITION
C
DO 30 M = 1,NWELL
  ID = IDW(M)
  QT(ID) = 0.0
  IF (ISHUT(ID).EQ.1) THEN
    DO 35 IWB = 1,NWBC(ID)
      QB(ID,IWB) = 0.0
    DO 40 L = 1,NPHAS
      Q(ID,IWB,L) = 0.0
40 CONTINUE
35 CONTINUE
  PWF(ID) = -999.0
GO TO 30
ENDIF
C CALCULATE THE PRODUCTIVITY INDICES FOR EACH WELL
C
DO 50 IWB = 1,NWBC(ID)
  IJK = IJXPOS(IWC(ID,IWB),JWC(ID,IWB),KWC(ID,IWB))
DO 56 L = 1,NPHAS
  IF (VIS(IJK,L).GE.ONEM5) PI(ID,IWB,L) =
& WELNBX(ID,IWB)*RPERM(IJK,L)/VIS(IJK,L)

C add some codes here to include the non-newtonian injectivity model for GAS
C phase
C wshar=1 (set in the input file), consider the model, otherwise, do not
C consider
C
if( (wshar.eq.1).and.(L.eq.NPHAS) ) then
  if( iflag(id).eq.1.or.iflag(id).eq.3 ) then
    PI(ID,IWB,L) =
& WDX_gas(ID,IWB)*RPERM(IJK,L)/VIS(IJK,L)
  endif
endif
C end of the codes
CONTINUE

PIB(ID, IWB) = 0.0
IF (KPRF(ID, IWB).EQ.1) THEN
  DO 61 L = 1, NPHAS
    PIB(ID, IWB) = PIB(ID, IWB) + PI(ID, IWB, L)
  END
ENDIF
CONTINUE

CALCULATE THE GRAVITY HEAD FOR EACH WELL

IF (IDIR(ID).EQ.3 .AND. IDEN.EQ.2) THEN
  IF (IFLAG(ID).EQ.1 .OR. IFLAG(ID).EQ.3) THEN
    DEN4 = 0.00433
    DEN5 = 0.02533
    DEN6 = -0.001299
    DO 70 L = 1, NPHAS
      GAMMAL(L) = DEN1*C(NBL+ID, 1, L)
      & +DEN3*C(NBL+ID, 3, L) +DEN4*C(NBL+ID, 4, L)
      & +DEN5*C(NBL+ID, 5, L) +DEN6*C(NBL+ID, 6, L)
      & +DEN7*C(NBL+ID, 7, L) +DEN8*C(NBL+ID, 8, L)
      IF (LMO) THEN
        DO 68 KO = 1, NNO
          KC = KO+NM001
          DENOT = DNOILC(KC)
          IF (L.EQ.3) DENOT = DNOME(KO)
          GAMMAL(L) = DENOT*C(NBL+ID, KC, L) + GAMMAL(L)
        END
      CONTINUE
    ELSE
      FACT2 = DEN2
      IF (L.EQ.3) FACT2 = DEN23
      GAMMAL(L) = FACT2*C(NBL+ID, 2, L) + GAMMAL(L)
    ENDIF
  CONTINUE
  DO 75 IWB = 1, NWBC(ID)
    GAMMAB(IWB) = 0.0
    SUMPIL = 0.0
    DO 80 L = 1, NPHAS
      SUMPIL = SUMPIL + PI(ID, IWB, L)
    CONTINUE
    DO 85 L = 1, NPHAS
      GAMMAB(IWB) = GAMMAB(IWB) + GAMMAL(L) * PI(ID, IWB, L) / SUMPIL
    CONTINUE
    ELSEIF (IFLAG(ID).EQ.2 .OR. IFLAG(ID).EQ.4) THEN
      DO 90 IWB = 1, NWBC(ID)
        IJK = IJKPOS(IWC(ID, IWB)), JWC(ID, IWB), KWC(ID, IWB)
        GAMMAB(IWB) = 0.0
        SUMPIL = 0.0
        DO 95 L = 1, NPHAS
          SUMPIL = SUMPIL + PI(ID, IWB, L)
        CONTINUE
        DO 100 L = 1, NPHAS
          GAMMAB(IWB) = GAMMAB(IWB) + DEN(IJK, L) * PI(ID, IWB, L) / SUMPIL
        CONTINUE
      ENDIF
    CONTINUE
    IF (ICoord.EQ.4) THEN
DO 106 IWB = 2,NWBC(ID)
    I = INC(ID,IWB-1)
    K = KWC(ID,IWB-1)
    IK = I - (K-1)*NX
    IJK = IJKPOS(INC(ID,IWB-1),JWC(ID,IWB-1),KWC(ID,IWB-1))
    IF (KWC(ID,IWB-1).EQ.1) THEN
       DELZA = 0.5*(DNZ(IK)+HZB(I))
    ELSE
       DELZA = 0.5*(DNZ(IK)+DNZ(IK-NX)*ALZ1(IJK-NXNY))
    ENDIF
    I = IWC(ID,IWB)
    K = KWC(ID,IWB)
    IK = I + (K-1)*NX
    IJK = IJKPOS(IWC(ID,IWB),JWC(ID,IWB),KWC(ID,IWB))
    IF (KWC(ID,IWB).EQ.1) THEN
       DELZB = 0.5*(DNZ(IK)+HZB(I))
    ELSE
       DELZB = 0.5*(DNZ(IK)+DNZ(IK-NX)*ALZ1(IJK-NXNY))
    ENDIF
    HEAD(ID,IWB) = HEAD(ID,IWB-1)+0.5*(GAMMAB(IWB-1)*
                                 DELZA+GAMMAB(IWB)*DELZB)
106    CONTINUE
ELSE
    DO 110 IWB = 2,NWBC(ID)
    HEAD(ID,IWB) = HEAD(ID,IWB-1)+0.5*(GAMMAB(IWB-1)*
                                 DX(KWC(ID,IWB-1))+GAMMAB(IWB)*DX(KWC(ID,IWB)))
110    CONTINUE
ENDIF
C RATE CONSTRAINT INJECTOR
C IF (IFLAG(ID),.EQ.1) THEN
   SUMPI = 0.0
   DO 120 IWB = 1,NWBC(ID)
      SUMPI = SUMPI + PIB(ID,IWB)
120    CONTINUE
C DO 150 IWB = 1,NWBC(ID)
Q(ID,IWB) = 0.0
   DO 155 L = 1,NPHAS
      Q(ID,IWB,L) = QI(ID,L)*PIB(ID,IWB)/SUMPI
      QB(ID,IWB) = QB(ID,IWB)+Q(ID,IWB,L)
155    CONTINUE
150    CONTINUE
ENDIF
C RATE CONSTRAINT PRODUCER
C IF (IFLAG(ID),.EQ.4) THEN
   SUMPI = 0.0
   DO 160 IWB = 1,NWBC(ID)
      SUMPI = SUMPI + PIB(ID,IWB)
160    CONTINUE
C DO 180 IWB = 1,NWBC(ID)
   QB(ID,IWB) = QI(ID,1)*PIB(ID,IWB)/SUMPI
   IF (KPRF(ID,IWB).EQ.1) THEN
      DO 180 L = 1,NPHAS
         Q(ID,IWB,L) = QB(ID,IWB)*PI(ID,IWB,L)/
& PIB(ID, IWB)
180 CONTINUE
ENDIF
170 CONTINUE
ENDIF

C PRESSURE CONSTRAINT INJECTOR/PRODUCER WELL
C CALCULATE THE IMPLICIT TERMS FOR THE PRESSURE EQ.
C
IF (IFLAG(ID).EQ.3.OR.IFLAG(ID).EQ.2) THEN
   DO 190 IWB = 1, NWBC(ID)
      IJK = IJKPOS(IWC(ID,IWB),JWC(ID,IWB),KWC(ID,IWB))
      PWFR(ID,IWB) = PWF(ID)
      IF (IDIR(ID).EQ.3) PWFR(ID,IWB) = PWFR(ID,IWB) + HEAD(ID,IWB)
      SUMPC = 0.0
      DO 195 L = 1, NPHAS
         SUMPC = SUMPC + PI(ID,IWB,L) * PRC(IJK,L)
      195 CONTINUE
      QB(ID,IWB) = PIB(ID,IWB) * PWFR(ID,IWB) - SUMPC
      AC(IJK) = AC(IJK) + PIB(ID,IWB)
   190 CONTINUE
ENDIF
30 CONTINUE

C EXTERNAL BOUNDARY CALCULATIONS FOR RADIAL GEOMETRY
C
IF (ICOORD.EQ.2) THEN
   COED = LOG(RP(NX)/R(NX))
   M = NWELL+1
   IDW(M) = NWELL+1
   ID = IDW(M)
   IFLAG(ID) = 3
   DO 400 K = 1, NZ
      IJK2 = K*NX
      WELNDX(ID,K) = 2.*PIE*6.3266*PERMX(IJK2)*DZ(K)/COED
   DO 410 L = 1, NPHAS
      PI(ID,K,L) = 0.0
   410 CONTINUE
   PIB(ID,K) = 0.0
   DO 420 L = 1, NPHAS
      IF (VIS(IJK2,L).GE.0.9995) PI(ID,K,L) =
         & WELNDX(ID,K)*RPERMX(IJK2,L)/VIS(IJK2,L)
      PIB(ID,K) = PIB(ID,K) + PI(ID,K,L)
   420 CONTINUE
400 CONTINUE
C
   DO 530 K = 1, NZ
      IJK2 = K*NX
      GAMMAAB(K) = 0.0
      HEAD(ID,K) = 0.0
      IF (IDEN.EQ.2) THEN
         DO 540 L = 1, NPHAS
            GAMMAAB(K) = GAMMAAB(K) + DEN(IJK2,L)*PI(ID,K,L)/PIB(ID,K)
         540 CONTINUE
      ENDIF
530 CONTINUE
C
   PE(1) = PE(NX)
   DO 550 K = 2, NZ
      IJK2 = K*NX
      HEAD(ID,K) = HEAD(ID,K-1) + 0.5*(GAMMAAB(K-1)*DZ(K-1) +
* GAMMA(K)*DZ(K))
    PE(IJK2) = PE(1)+HEAD(ID,K)

550 CONTINUE
C
    DO 560 K = 1,NZ
    IJK2 = K*NK
    QB(ID,K) = PE(IJK2)*PIB(ID,K)
    AC(IJK2) = AC(IJK2) + PIB(ID,K)
    BV(IJK2) = BV(IJK2) + QB(ID,K)

560 CONTINUE
ENDIF
C
    RETURN
END