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Foam Assisted Gas Oil Gravity Drainage in Naturally-Fractured Reservoirs

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Abstract

This paper introduces a novel enhanced-oil-recovery concept for naturally-fractured reservoirs. We use foam to create a viscous pressure drop along the fracture that is directly transferred to the oil-bearing matrix and accelerates the oil production. We developed an expression that predicts the maximum oil rate depending on the injected gas rate and properties of the foam generated in the fracture. The results of the numerical simulation are in good agreement with the developed model.

1. Introduction

1.1. Gas-oil gravity drainage (GOGD)

In fractured reservoirs much of the conductivity is in the fracture network while much of the oil is in the matrix. The high permeability contrast between the fracture and the matrix limits the performance and the efficiency of improved oil recovery (IOR) techniques as the injected fluid prefers to flow in the fracture rather than the matrix. Gas-oil gravity drainage (GOGD) is considered to be one of the main recovery mechanisms in the (non-water-wet-) naturally-fractured reservoirs [1-3]. In fact after initial depletion of the fracture network gas-oil and oil-water contacts are established in the fracture. At this (quasi-) equilibrium condition, the matrix oil can be produced by gravity forces: GOGD above the fracture gas-oil contact (FGOC) and water-oil gravity drainage (WOGD) below the fracture water-oil contact (FOWC) (Figure 1). These mechanisms rely on the density difference between oil and gas (GOGD), and oil and water (WOGD) as driving force. In the case of a water-wet matrix oil can also be produced by capillary forces; however, in this study we mainly focus on gravity forces and neglect capillary forces.

To maintain the production in the GOGD, the oil rim in the fractures must be lowered through the production. However, the production of the oil-rim results in the early gas breakthrough and dramatic reduction of the production (rates go back to the natural gravity-drainage rate, see Figure 4 for a typical production curve). In the production of fractured reservoirs under GOGD the balance between the oil rim and the gas injection rate should be maintained: if wells are overproduced they will gas-out or water-out and therefore they need to be closed-in or at least reduced in rate allowing the rim to build up again.

Gravity drainage is a slow process and requires continuous injection of gas (1) to replace the produced oil, and (2) to avoid the rise of the oil rim in the fracture. Moreover, due to the high permeability of the fracture and the low viscosity of the gas, the viscous forces are not significant.

1.2. Foam in fractured reservoirs

Foam has been suggested (and demonstrated) as a solution to control the high mobility of the (miscible and immiscible) gas in the reservoirs and for enhancing oil recovery [e.g. 4-7]. Foam is generated by mixing of the gas and a surfactant solution (and/or nanoparticles [8]) in porous media via formation of bubbles separated by thin liquid films (lamellae). Subsequently, gas becomes a discontinuous phase and its mobility is greatly reduced. The classification of foams is based on their bubble size and gas fraction. In bulk foam (the foam that is created in an open space) the characteristic length of the foam bubbles is smaller than the characteristic length scale of the space confining foam and therefore the bubble shape is determined by the gas volume fraction (wet foam and dry foam) [4]. In porous media, due to the confined geometry, the bubbles take the shape of the pore and span around the pores. Therefore, it is possible to have bubbles that occupy more than one pore space. We expect foam in fractures to behave like bulk foam rather than porous-media foam. The strength of foam is measured by the magnitude of the pressure drop that is created along the medium. To create a large pressure drop (i.e. higher apparent viscosity) very strong foams, and therefore very small bubbles, are required. A summary of literature on foam in fractures is presented in Appendix A.

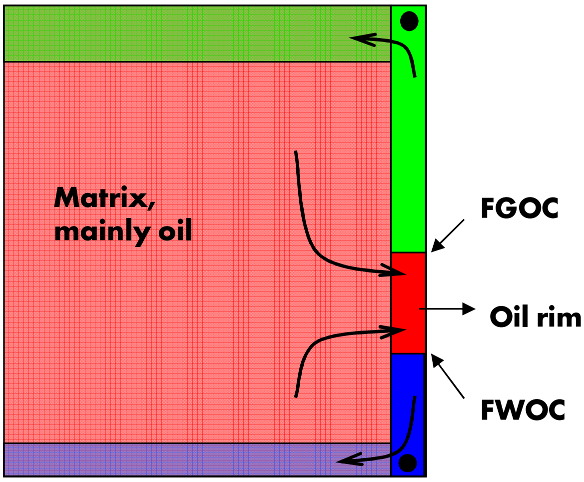

Figure 1: Fracture-matrix in equilibrium after the primary depletion of the fracture network

According to Hirasaki and Lawson [9] the main factors influencing the apparent foam viscosity in the smooth capillaries are due to the dynamic changes at the gas-liquid interfaces. The resulting viscosity is the sum of the following three contributions (Figure 2):

1- Slugs of the liquid between the gas bubbles resist flow

2- Viscous and capillary forces result in interface deformation against the restoring force of the surface tension. The different curvatures at the front and the rear of a moving bubble dictate the pressure drop required for the bubble motion.

3- The surfactant is swept to accumulate at the back and be depleted at the front of the bubble, which causes a surface-tension gradient that resists the flow.

Accordingly, the pressure drop in the fracture, in the absence of gravity, can be calculated as (for details see Appendix B or refs [9-10])

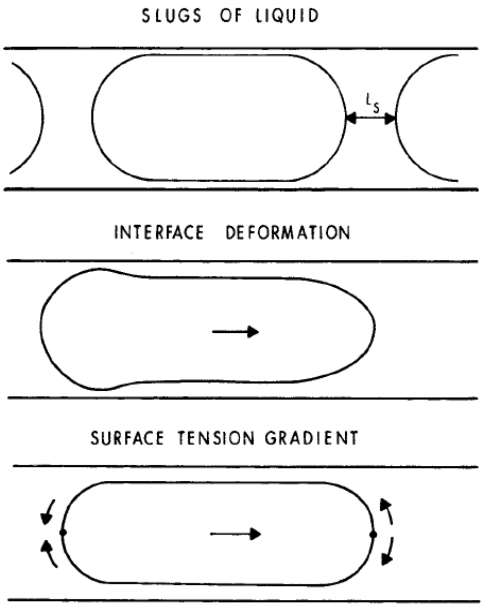

Figure 2: Mechanisms affecting apparent foam viscosity in smooth capillaries [9]

$$\nabla p_f = \frac{12U}{b^2}\left[\left(1-f_g\right)+0.56\left(\frac{3\mu^{liq}U}{\sigma}\right)^{-1/3} f_g^{1/2}\left(\frac{b}{r_B}\right)^{3/2}\right]\mu^{liq} \quad . \tag{1}$$

The equation is derived by neglecting surface-tension gradient effects, nevertheless, our analysis (Appendix B) shows that the surface-tension gradient contribution to the apparent viscosity cannot be neglected and the model needs modifications as confirmed by the authors [11].

The purpose of this paper is (1) to study the feasibility of improving GOGD by foaming the gas in the fracture, i.e. by reducing the gas mobility in the fracture and creating additional viscous pressure drop along the fracture, (2) to investigate the sensitivity of the process to different parameters, and (3) to highlight the important parameters for further investigations (experimentally and numerically). The structure of the paper is as follows. First we derive an equation that predicts the maximum oil rate similar to the GOGD models. Secondly we explain the current foam model and adapt it to simulate the foam behavior in the fracture. Next we present the results of our simulation and discuss the effect of different parameters. We end the paper with some concluding remarks highlighting the important aspects of the process.

2. Theory

Consider a 1-D vertical stack of height H and width W that is connected to a fracture of width b from one side (Figure 3). The matrix has homogeneous permeability of k_{mat} and porosity of φ and is initially filled with oil. The fracture has homogeneous permeability of k_{frac}. We assume that foam is only created in the fracture and therefore in the absence of foam in the matrix, the pressure gradient in the draining matrix is that of gas in the fracture and not the hydrostatic oil gradient (The bottom part of the matrix is filled, at least initially, with oil. The pressure at the top of this oil column is the pressure of the mobile gas that is connected to the fracture and therefore has the pressure of fracture gas at the same height. On the other hand, the pressure at the open bottom is also equal to the fracture gas at the bottom of the fracture. Consequently, the gradient over the zone fully filled with oil is also the gas gradient). The gas is assumed to have infinite mobility. The oil flows due to the gravity effects. When a surfactant solution and gas are co-injected, the mobility of the gas in the fracture is reduced by foam. The foam formation creates the pressure drop of Δp_{foam} along the fracture and can be directly seen in the matrix as well.

The oil flow rate at point z in the matrix is given by

$$q_o = -\frac{kk_{ro}}{\mu_o} A \frac{d\Phi_o}{dz} \tag{2}$$

where A is the cross-sectional area of the block.

2.1. Gas-oil gravity drainage (GOGD)

In a gas oil gravity drainage scheme the fracture is filled with gas. It is usually a good approximation to assume that the gas is in hydrostatic equilibrium and to ignore any viscous pressure drop due to gas circulation through the fracture system.

The pressure at the top of the stack is then related to the pressure at the bottom of the stack by

$$p_{top} = p_{bottom} - \rho_g gH$$

and the flow potential is given by

$$\Phi_o = p_{bottom} + \frac{p_{top} - p_{bottom}}{H} z + \rho_o gz \tag{3}$$

$$\Phi_o = p_{bottom} + \left(\rho_o - \rho_g\right) gz$$

So,

$$\frac{d\Phi_o}{dz} = \Delta\rho_{og} g$$

and the oil rate is

$$q_o = -\frac{kk_{ro}}{\mu_o} A\Delta\rho_{og} g \tag{4}$$

Equation (4) provides the maximum rate of the oil production by the gravity drainage in the absence of capillary forces before the gas breakthrough. In the presence of capillary forces, the capillary-pressure gradient is added to the potential gradient. After the gas breakthrough the oil rate decreases significantly (for details see ref. [12]).

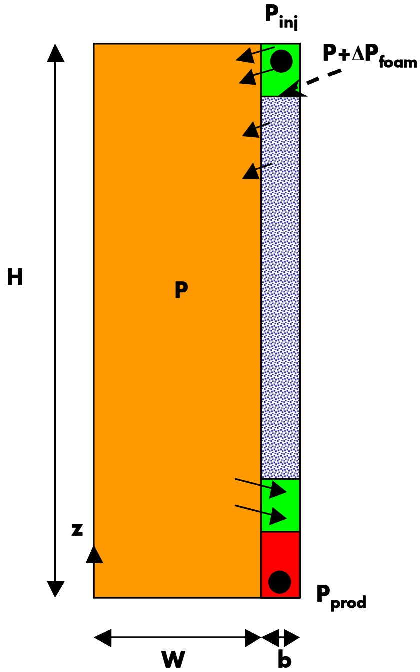

Figure 3: Geometry of the model

2.2. Foam assisted gas-oil gravity drainage (FAGOGD)

In this case foam is generated in the fracture (but destroyed in the matrix) and therefore due to foam flow a viscous pressure drop is induced along the fracture. Note that creation of foam films increases the apparent viscosity of gas; hence, foam flow could be equivalent to flow of a viscous gas. Assuming that Darcy's law is valid for foam flow in fractures we can write

$$q_g = \frac{A_{frac} k_{frac}}{H} \frac{k_{rg}}{\mu_{foam}} \Delta p_{foam} = T_{frac} \lambda_{foam} \Delta p_{foam} \tag{5}$$

In the following we derive an expression for the maximum oil-production rate when gas is foamed in the fracture and its mobility is reduced. The pressure at the top of stack is

$$p_{top} = p_{bottom} - \rho_g g H + \Delta p_{foam} \tag{6}$$

From eq. (3),

$$\Phi_o = p_{bottom} + \frac{\Delta p_{foam}}{H} z + \Delta \rho_{og} g z \tag{7}$$

$$\frac{d\Phi_o}{dz} = \frac{\Delta p_{foam}}{H} + \Delta \rho_{og} g \tag{8}$$

from which we can calculate the oil production rate,

$$q_o = -\frac{k k_{ro}}{\mu_o} A \left(\Delta \rho_{og} g + \frac{\Delta p_{foam}}{H} \right) \tag{9}$$

Comparing Eq. (4) and Eq. (5) the additional produced oil will therefore be

$$\Delta q_o = \frac{k k_{ro}}{\mu_o} A \left(\frac{\Delta p_{foam}}{H} \right) \quad . \tag{10}$$

In terms of the gas flowrate and the fracture transmissibility coefficient, T_{frac}, we can write,

$$q_g = \frac{A_{frac}k_{frac}}{H}\frac{k_{rg}}{\mu_{foam}}\Delta p_{foam} = T_{frac}\lambda_{foam}\Delta p_{foam} \tag{11}$$

where λ_{foam} is the apparent foam mobility. Re-arranging Eq. (11) gives

$$\Delta p_{foam} = \frac{q_g}{T_{frac}\lambda_{foam}} \tag{12}$$

combining Eqs. (10) and (12) provides,

$$\Delta q_o = \frac{T_{mat}\lambda_o}{T_{frac}\lambda_{foam}} q_g \tag{13}$$

Equation (13) provides a relation between the gas flowrate and the additional oil that can be produced over GOGD in a fractured reservoir. In this equation T_{mat} and T_{frac} are parameters that could be obtained from different data sources, e.g., petro-physical data. Finally, λ_{foam} and its dependency on the other parameters, such as foam quality, fracture aperture, surfactant type, flowrates and etc., can be measured through carefully-designed experiments in the lab.

3. Numerical simulations

3.1. Model description

The 2-D conceptual model used in the simulations (22×25×1) consists of a matrix with width of 10 m and fracture with width of 1 mm on the side. The height of the stack is 60 m. The matrix is initially saturated with 90% oil and 10% water. The fluids are injected from top of the fracture and produced from the bottom of the fracture. The model parameters and fluid properties are summarized in Table C.1 and Table C.2 in Appendix C. For simplicity sake we neglect the capillary forces in our model.

3.2. GOGD performance

The two characteristic periods in gravity drainage consist of an initial period of constant maximum drainage rate followed by a period of declining rate after gas breakthrough. Hagoort [12] developed an analytical model for a stable *incompressible one-dimensional* GOGD flow in a homogenous stack, assuming *infinite mobility* for gas. His results show that the decline rate of gravity drainage is dependent on the Corey exponent of the oil relative permeability. Figure 4 compares the GOGD oil rates calculated from Hagoort's analytical model [12] and MoReS (Shell in-house simulator) for the reservoir and fluids described in Table C.1 and Table C.2 in Appendix C. The discrepancy between these two curves is due to the fact that the analytical model is derived for a 1-D stack open at the bottom, while in our model the bottom is closed and 2-D-flow effects become important. The larger the width over height ratio of the block the larger the discrepancy with the analytical model. In this case the *W/H* ratio is 0.16. The other reasons include grid cell number (numerical dispersion) and finite mobility of the gas.

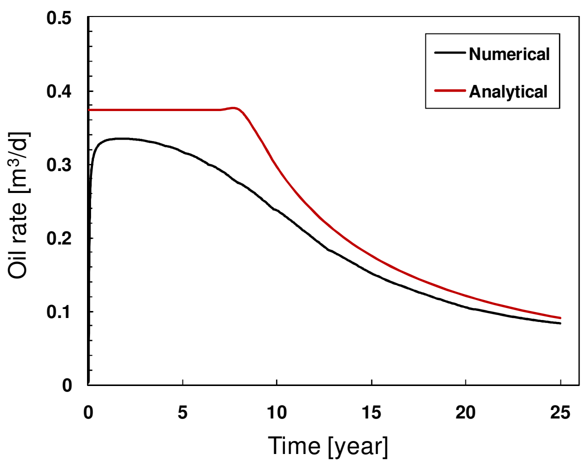

Figure 4: Comparison of analytical and numerical GOGD oil rates

3.3. Foam modeling

The foam model assumes formation of foam wherever gas and surfactant co-exist. Since no foam model is yet available for (vertical-) fractured media, we use the same foam model, namely mobility reduction model or steady-state foam model, for the fracture and the matrix. Note that foam might have different properties and strength in the fracture and in the matrix. This study focuses on understanding the effect of foaming of the gas in the fractures and evaluating the magnitude of the foam strength required for creation of viscous pressure drops along the fracture. Consequently, details of foam rheology and foam model in fractured media are not discussed in this paper and will be part of future work.

The mobility reduction model scales down the gas mobility by a factor, *FM*, which is defined as

$$FM = \frac{1}{1+MRF \cdot F_1 \cdot F_2 \cdot F_3 \cdot F_4 \cdot F_5 \cdot F_6 \cdot \ldots} \quad , \tag{14}$$

in this equation MRF is the maximum mobility reduction factor and F_i's take into account the effects of the other parameters such as oil saturation, water saturation, surfactant concentration and capillary effects. According to this expression, foam is formed when the saturation of water in the grid cell is above the critical water saturation, S_w^*, and that of oil is below critical oil saturation, S_o^*. Foam collapses when $S_w < S_w^*$ or $S_o > S_o^*$. The foam parameters used in this study are given in Table C.3 in Appendix C.

4. Simulation results

In this section, we first consider the case where foam is not tolerant to oil, i.e., it breaks down when the oil saturation is above a certain threshold value. In this case foam is only formed in the fracture and breaks down in the matrix and flows as gas. We investigate effects of different parameters such as foam strength, fracture permeability, aspect ratio, gas production rate, etc. on the magnitude of the pressure drop and the amount of produced oil. In Section 4.7 we assume that foam is oil-tolerant, i.e., oil does not affect the foam stability and hence foam can also be formed in the matrix. The production and pressure profiles of each case will be explained in detail. Note that only Section 4.7 discusses oil-tolerant foam and in the other sections the critical oil saturation of 0.20 was used in the simulations.

4.1. Effect of foam on GOGD rate

Figure 5 shows the propagation of the surfactant front into the matrix (red color). Since the oil saturation is above the critical oil saturation in the matrix ($S_o>0.20$), there is no foam in the matrix (even though surfactant is available for foaming), i.e., the injected gas has (its original) high mobility in the matrix.

Figure 6 shows the effect of foam on the GOGD oil rate. The gas-rate constraint on injection well was set equal to that of the GOGD case, i.e., slightly above the maximum oil production rate in GOGD. As can be seen foaming of the gas increases the maximum plateau oil rate, which leads to increase of the oil recovery. The amount of the produced oil increases with increasing foam strength for the same gas constraint. The oil rate decreases after the gas breakthrough similar to the GOGD case. Figure 7 shows the pressure of the producer. In the case of GOGD, only gas is injected at a constant pressure of 25 bar and the difference between pressures of the injector and the producer (drawdown) corresponds to the gas hydrostatic pressure at reservoir conditions. Indeed, due to the low viscosity (high mobility) of the gas and high fracture permeability, there is almost no resistance (pressure drop) along the fracture. Creation of foam in the fracture creates a pressure drop because the apparent viscosity of foam is orders of magnitude higher than that of gas. For example, with the foam parameters used in our simulations, in the case of MRF=1×10^5 the gas viscosity in the fracture is increased to 4.0 cP and in the case of MRF=5×10^5 to about 20 cP. This causes an additional (vertical-) pressure drop of 0.16 bar (MRF=1×10^5) and 3.1 bar (MRF = 5×10^5) in the fracture respectively for a gas rate of 32 Sm^3/d. This pressure difference is directly transferred to the matrix. The maximum oil rates produced due to these pressure drops are in good agreement with the oil rates calculated from Eqs. (9) and (12), as shown in Table 1. The minimum in the pressure profile corresponds to the time at which the whole fracture is filled completely with foam. The pressure increases afterwards due to gas breakthrough in the production well.

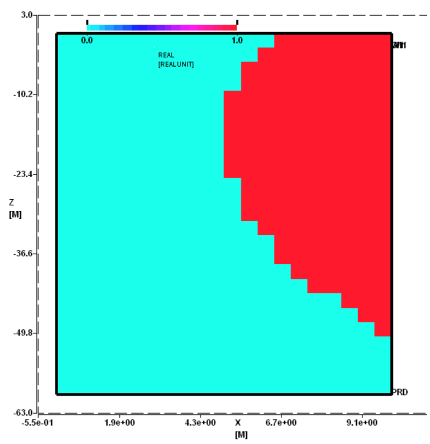

Figure 5: Propagation of surfactant in the matrix after 25 years (MRF=5×10^5)

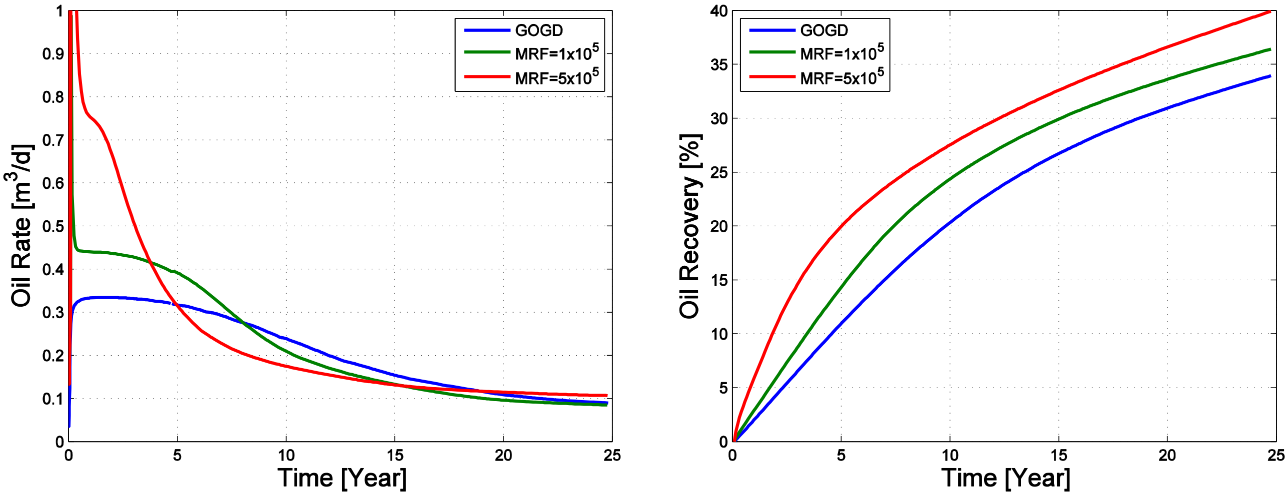

Figure 6: Effect of foam and foam strength on oil production

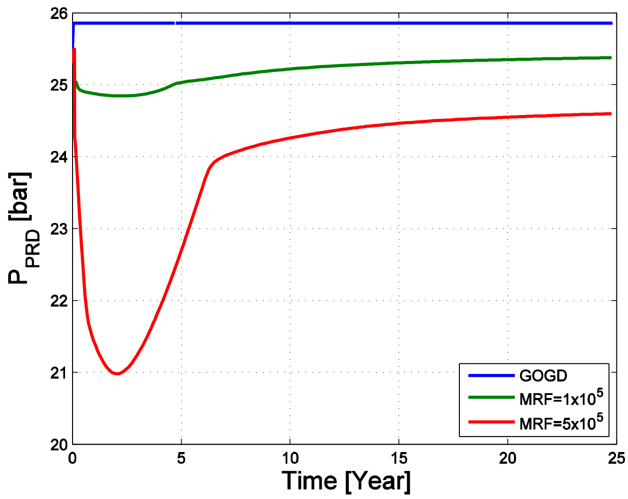

Figure 7: Pressure of the producer in different cases

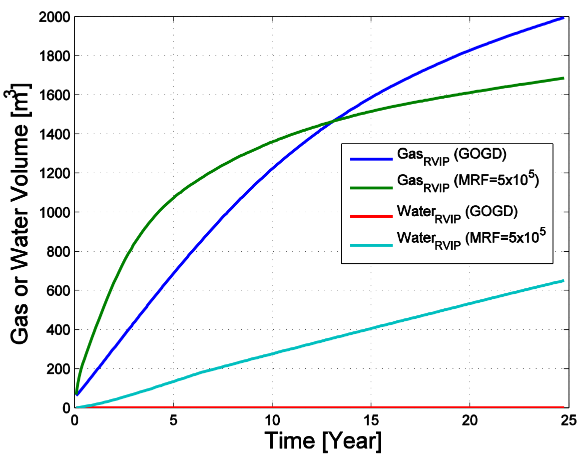

Figure 8: Amounts of diverted gas and water into matrix (at reservoir conditions).

As a result of the induced pressure difference between top and bottom of the fracture oil production is accelerated when foam is created in the fracture. The produced oil is then replaced by gas and water (more strictly surfactant solution). Compared to GOGD more gas (and water) will enter the matrix (higher q_g). In the case of foam injection, a fluid with lower mobility flows in the fracture and thus pressure is higher in the fracture. This causes the horizontal pressure drop observed between fracture and matrix in the simulations (between 0.1-0.6 bar in our simulations depending on foam strength). Figure 8 shows the amount of diverted gas from the fracture to the matrix. It is clear that in the case of foam the amount of diverted gas is higher than GOGD. In the foam case the surfactant solution is co-injected with the gas. Part of the injected solution is diverted into the matrix as well, as shown also in Figure 8.

Table 1: Comparison of plateau oil rates obtained from MoReS and calculated by Eq. (9) and (12) for different foam strengths

Run	dP , μ	oil rate (MoReS) [m^3/d]	oil rate (Eqs. (9) and (12)) [m^3/d]
MRF=1×10^5	0.16 bar , 4.0 cP	0.43	0.39
MRF=5×10^5	3.1 bar , 20 cP	0.76	0.71

4.2. Effect of gas-production rate

The higher rate of the produced gas causes additional viscous pressure drop along the fracture according to Darcy's law. In the previous simulations the gas-rate constraint on the producer was set to 32 Sm^3/d. If we double the rate, in the case of the GOGD due to low viscosity of the injected gas the additional viscous pressure drop is so low that it hardly affects the recovery. However, in the case of foam by increasing the gas-rate constraint a higher viscous pressure drop occurs along the fracture, which enhances the oil recovery (Figure 11). The comparison with Eq. (12) is shown in Table 2.

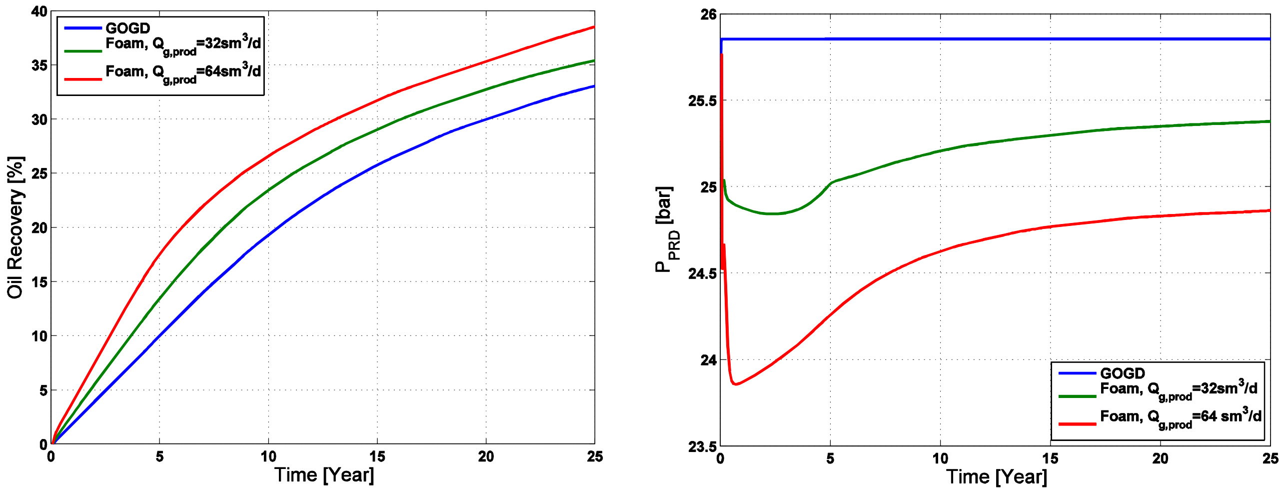

Figure 9: Effect of the gas-rate constraint on the performance of the foam injection (MRF=1×10^5)

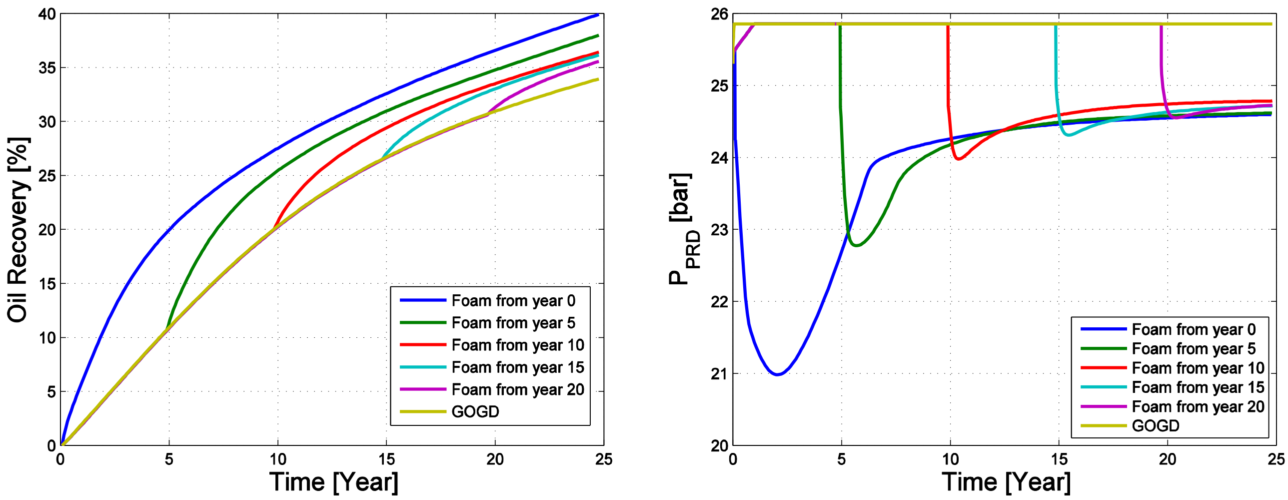

Figure 10: Effect of foam injection on oil rate and pressure in a partially depleted stack (MRF=5×10^5)

Table 2: Comparison of oil rates obtained from MoReS and calculated from Eqs. (9) and (12) for different gas-production rates

q_g [sm^3/d]	dP , μ	oil rate (MoReS) [m^3/d]	oil rate (Eqs. (9) and (12)) [m^3/d]
32	0.16 bar , 4.0 cP	0.43	0.39
64	1.2 bar , 4.2 cP	0.55	0.51

4.3. Depleted stack

We investigated the effect of foam injection into a stack that has already been under production by the GOGD mechanism. The results are shown in Figure 10. In all cases the oil recovery increases immediately after foam injection; however, the later the foam injection starts the lower the recoverable oil is. Since the gas has already broken through in the matrix in these cases, injection of foam causes lower pressure drop and therefore the production is low.

4.4. Effect of fracture transmissibility

Another important parameter in the application of foam in the fractures is the transmissibility of the fracture: the higher the fracture permeability the lower the viscous pressure drop along the fracture. This means that for the fractures with higher transmissibility very strong foam is required to create the desired viscous pressure drop. Figure 11 compares the oil production and pressure profiles of the GOGD case and two foam cases where we used k_{frac}=10000 D. When foam parameters similar to the ones in the case of k_{frac}=1000 D are used, there is small difference between the production profiles of the GOGD and the foam case as foam is not able to create sufficient pressure drop. However, using stronger foam (MRF=5×10^6) increases the oil rate. Note that in this case the apparent foam viscosity is about 200 cP. If the fracture permeability is too high, the injection of foam might not create sufficient pressure drop to improve the GOGD. The limits could be determined by performing experiments.

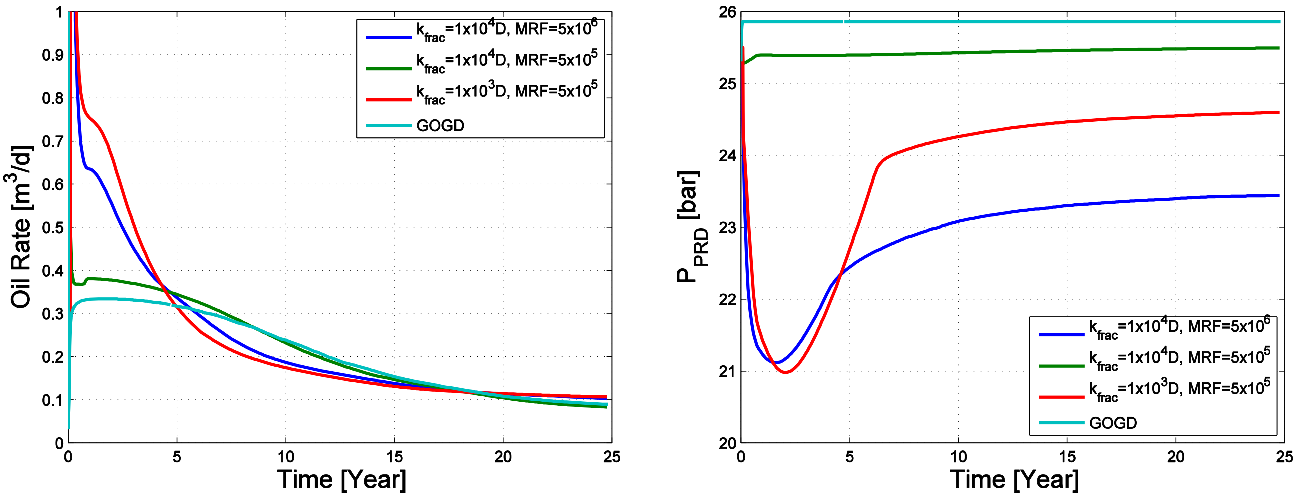

Figure 11: Effect of fracture permeability on behavior of foam

4.5. Fracture spacing

With decreasing the fracture spacing (W/H ratio) the accuracy of analytical GOGD models [12, 2] increases since the models are derived for 1-D flow. We performed simulations to investigate the effect of W/H ratio on the performance of foam. It turns out that as the W/H ratio increases the performance of the foam becomes better, i.e., the difference between the oil recoveries of the GOGD and foam assisted GOGD becomes larger. Obviously for higher W/H ratios gravity is less efficient and therefore creation of viscous forces by foam makes results in larger differences compared with the cases with lower W/H ratio where gravity is more efficient.

4.6. Effect of oil saturation in the matrix

If foam is aimed to improve the GOGD process the formation of foam in the matrix is not desirable. If the initial oil saturation in the matrix is higher than S_o^* (strong) foam will not form in the matrix until the oil saturation in below S_o^*. This will especially be the case at the boundary between the matrix and the fracture where oil saturation becomes low due to continuous flushing by gas and water. Until this time, the pressure drop caused by foam is still maintained in the matrix and therefore the oil rate will be higher than the GOGD case. The creation of foam at the boundary will disconnect the fracture and the matrix and therefore the *foam-induced viscous pressure* will not be transferred to the matrix. Moreover, as the oil saturation in the matrix decreases inside the matrix, more foam will be generated inside the matrix and will propagate with surfactant front (neglecting surfactant adsorption). This process is governed by existence of the horizontal pressure drop due to flow of foam.

Foam inside the matrix displaces oil as its viscosity is higher than that of oil (20 vs. 2 cP).

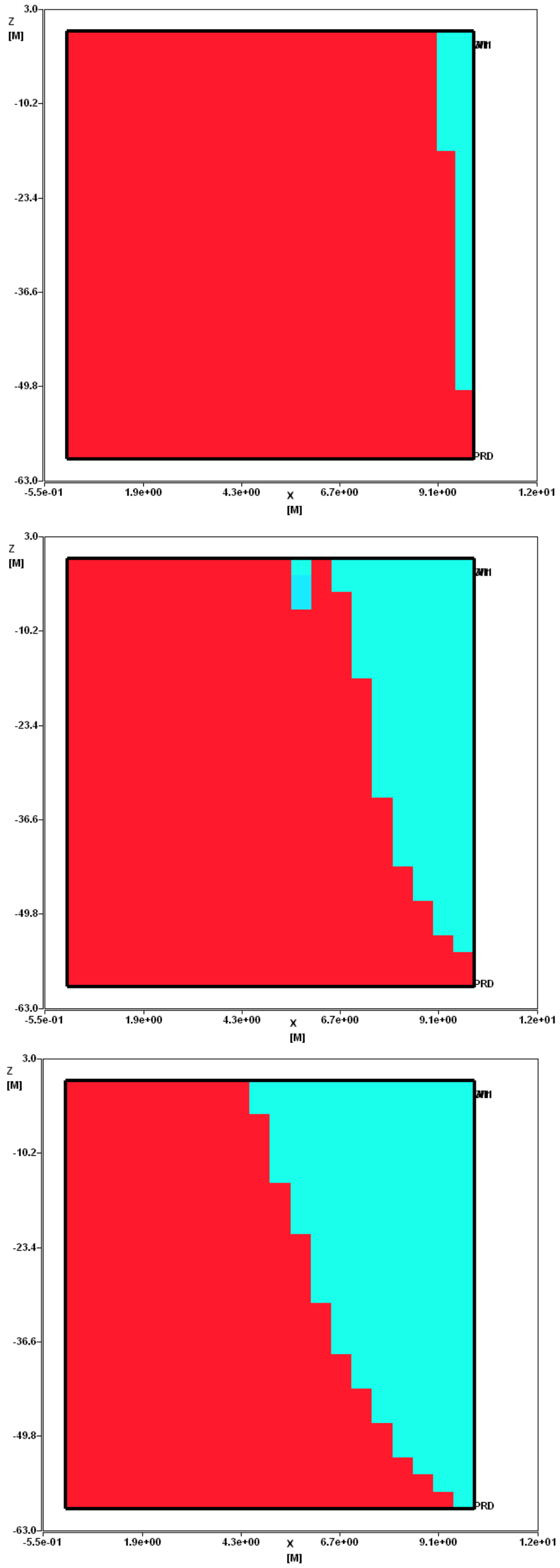

Figure 12: Foam front in the matrix at after 25 years of foam injection (from top: $S_o^*=0.35$, $S_o^*=0.50$ and $S_o^*=1.0$).

This effect can be simulated by varying the critical oil saturation in the foam model. Figure 12 shows the foam front after 25 years for three critical oil saturations used. In the case of $S_o^*=0.35$ foam is only formed at the boundary since the oil saturation is still high at other parts of the matrix. When more oil-tolerant foam ($S_o^*=0.5$) and indestructible foam ($S_o^*=1$) is used in the simulations foam is also formed inside the matrix. Flow of foam in the matrix creates a horizontal pressure drop and pushes oil in the matrix, as shown in Figure 13. The left part of the matrix produces under GOGD mechanism. The gas at the left part is a combination of dissolved gas (that is released because of pressure drop) and the gas that has not foamed initially in the matrix due to lack of the aqueous phase. Our simulations show that foam starts to be created from second year on. In the first year the gas that enters the matrix has still its original viscosity. Figure 14 compares the production rates and recoveries. The production at the later stages is higher when foam is more tolerant to oil. This is likely the oil that is displaced by foam in the matrix and therefore delayed. One interesting feature of these simulations is that when foam is more tolerant to oil, less surfactant solution but more gas is diverted into the matrix (Figure 15), because foam hinders the flow of water from fracture to matrix. In the case of $S_o^*=1$ foam is immediately formed in the matrix and to maintain the set gas flowrate constraint the pressure in the producer is decreased. However, in the case of $S_o^*=0.50$ initially the oil saturation in the matrix is above 0.50 and therefore until $S_o < S_o^*$ its pressure profile is similar to the $S_o^*=0.20$ case (Figure 16). Once the oil saturation is below 0.50, the pressure profile becomes similar to the $S_o^*=1.0$ case.

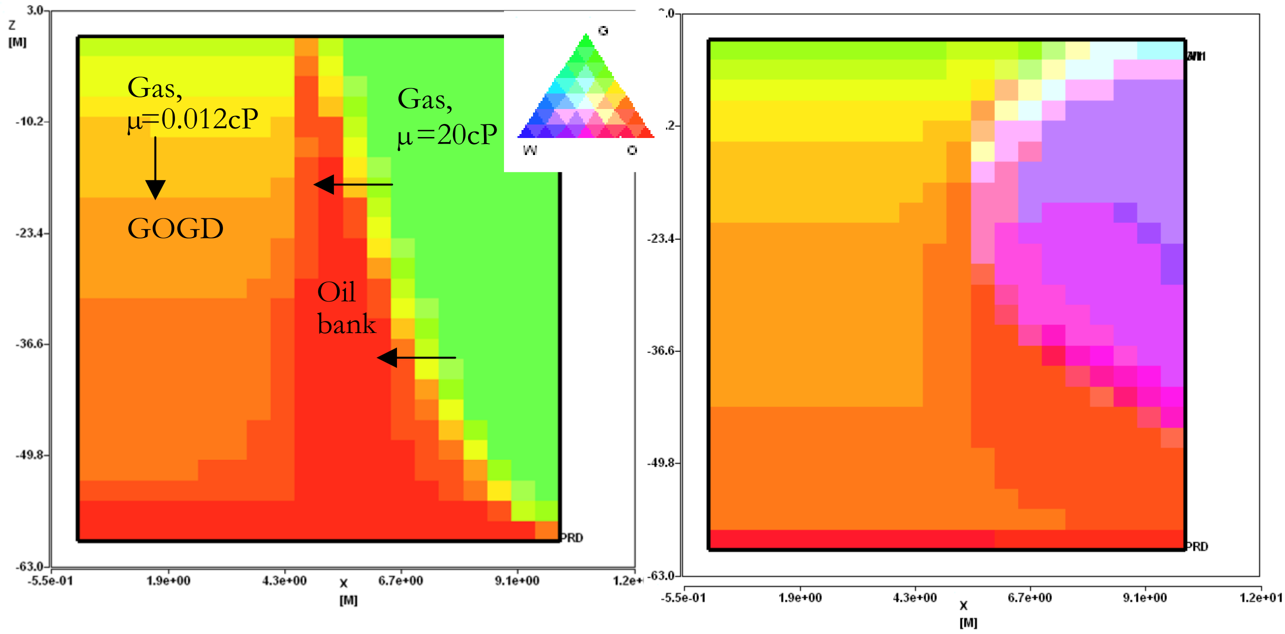

Figure 13: Fluid saturations in the matrix after 25 years: $S_o^*=1$ (left) and $S_o^*=0.20$ (right). In the left picture part of the reservoir is producing under GOGD while foam is pushing oil from the other side forming an oil bank.

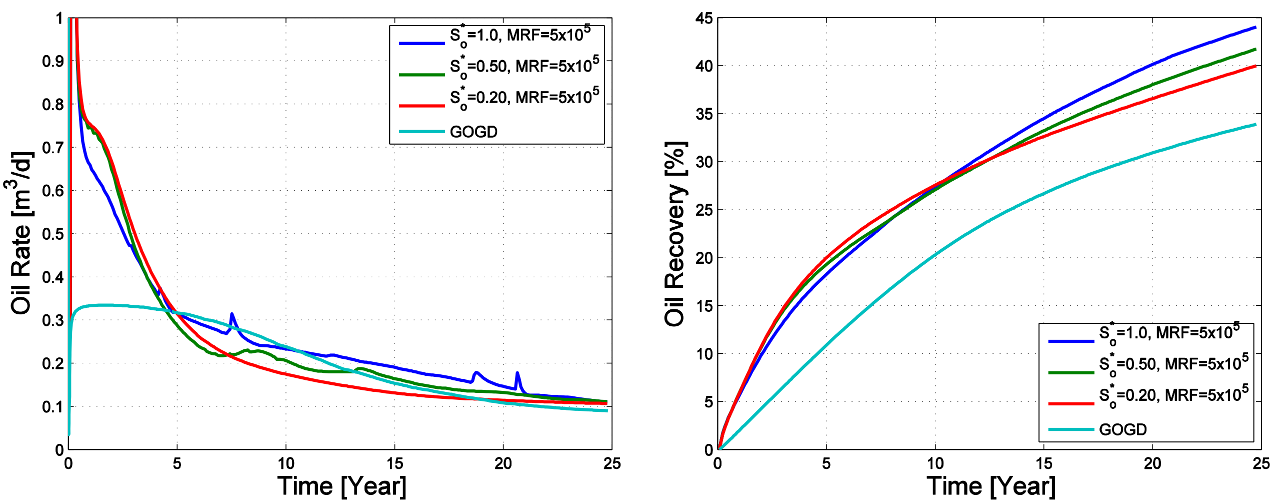

Figure 14: Oil rate and recoveries of indestructible foam ($S_o^*=1$) and oil-intolerant foam ($S_o^*=0.2$) with MRF=5×10^5.

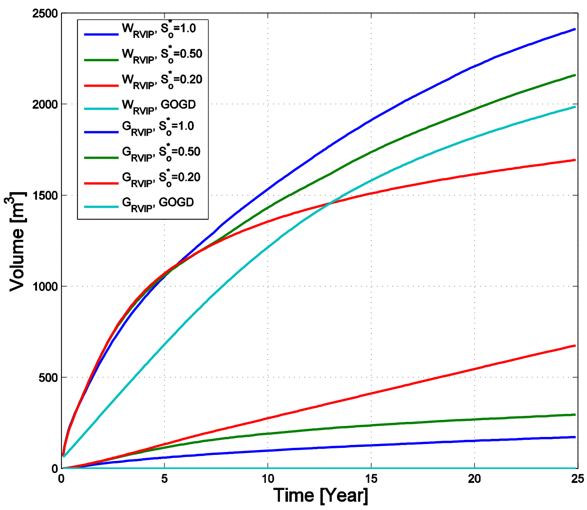

Figure 15: Amounts of diverted fluids into matrix for foam with different S_o^*.

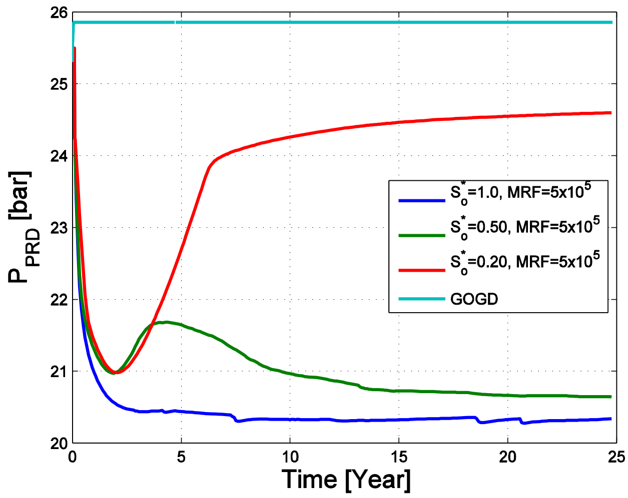

Figure 16: Pressure profiles with MRF=5×10^5 and different S_o^*.

5. Considerations

Our numerical simulations demonstrate a promising method for enhancing (or accelerating) oil recovery in the naturally fractured reservoirs. However, the following issues should be considered for future studies.

- ***Foam model in the fracture:*** We used the steady-state foam model to simulate the effect of foam. This model is developed for foam in porous media and not for foam in fractures. Although the values obtained for the foam (or gas) apparent viscosity are in agreement with the reported values in the literature, the current model might not properly capture the effect of other parameters on foam behavior in fractures. A suitable model for application of foam in fractured reservoirs should also consider gravity (which affects foam stability by accelerating foam-film drainage) and therefore the experiments should be performed vertically and not horizontally.

- ***Water (or surfactant solution) required for foaming:*** Due to gravity, water goes to the bottom. To force foaming the critical water saturation was set to 0.10 in this study. The rate of foam generation plays an important role here.

- ***Injection mode:*** Surfactant Alternating Gas (SAG) is not a proper way of foam generation in the fractures since the injected water will be immediately produced due to gravity. Pre-generated foam injection or co-injection of surfactant solution and gas are more practical for foam in the fractures. In this study we used co-injection mode, which basically assumes immediate foaming of the gas (equivalent to pre-generated foam).

- ***Transmissibility of the fracture:*** To create effective pressure drops along the fractures very strong foam is required.

The larger the transmissibility of the fracture the stronger the foam should be.

- ***Foam formation in the fracture:*** In reality there could be an oil film coating the fracture surface. This might be a problem for foam formation unless the injected surfactant changes the wettability of rock (removes the oil film).
- ***Foam destruction by oil in the fracture:*** The sensitivity of foam to oil is an important issue in the application of foam in the fractured reservoirs. The oil flows from the matrix into the fracture and therefore, at least in some parts of the matrix where the oil is produced, the oil saturation at the boundary between the matrix and the fracture is close to one or well above the critical oil saturation required to "kill" foam. In this case the kinetics of *foam generation and destruction* is the factor that determines the success of the foam injection. In fact foam generation (or re-generation) rate must be higher than its destruction rate such that it can sustain the induced pressure drop.
- ***Gas recycling:*** Increasing the gas-rate constraint can increase the amount of recoverable oil. The gas-rate constraint is determined by the capacity of the gas-recycling equipments. The higher the gas-recycling capacity the better the foam performance.
- ***Foam and other fracture-blocking agents:*** In the foam case, the creation of foam reduces the gas mobility only and when oil or water move from the matrix to the fracture, due to the high permeability of the fracture and the gravity, they are immediately produced. Consequently, the fracture is filled with the gas only. When the fracture permeability is reduced by other blocking agents, the mobility of all fluids is reduced (viscous forces dominate the flow rather than the gravity forces). Therefore, the fracture contains oil, water and gas at the same time, unlike the foam situation (for details see Appendix D).

6. Conclusions

- The surface-tension gradient contribution to the apparent viscosity of foam in parallel plates cannot be neglected and the model proposed by Yan et al (2006) [Eq. (1)] needs modifications.
- We developed a simple expression that approximates the maximum oil production before the gas breakthrough when a viscous pressure drop is created in the fracture,
- Injection of foam into the fractured reservoirs creates a viscous pressure drop along the fracture. This pressure drop is directly transferred to the matrix and accelerates the oil production,
- The maximum oil rates obtained from the MoReS simulator are in reasonable agreement with the rates obtained from the analytical model,
- Gas and water are simultaneously diverted into the matrix via the creation of horizontal pressure drop between the fracture and the matrix,
- Foam creation in the fracture is not equivalent to reducing the fracture permeability because in the former only the gas mobility is reduced while in the latter mobilities of all fluids are reduced,
- Very strong foams are required to create a pressure drop that can affect the oil production of the fractured reservoirs. The strength of foam depends on the fracture transmissibility for a certain pressure drop.
- Formation of foam in the matrix disconnects the fracture and the matrix and as a result the created viscous pressure is no longer seen in the matrix. This changes the production mechanism.

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Appendix A: Summary of literature on foam in fractures

The literature on foam in the fractures is scarce compared to foam in un-fractured porous media due to the apparent complexity of the fractured reservoirs and foam itself. Almost none of the published papers considers the effect of gravity. Majority of the experiments are performed in horizontal cores with a fracture along the length of the core. The main purpose and also outcome of these experiments was to divert gas or liquid from the fracture to the matrix. The results of these experiments cannot be applied directly to the fractured reservoirs where most fractures are vertically oriented and the effect of gravity is important. In the following we present a short summary of the main papers on this subject.

Kovseck et al. [13] studied the flow of nitrogen and pre-generated foam through a transparent replica of a natural rough-walled rock fracture with hydraulic aperture of 30μm. Their experiments showed that foam reduces the gas mobility by 100-540 times depending on the foam quality.

Alkan et al. [14] reported dynamic (immiscible-) CO_2 foam experiments utilizing an artificially fractured core. The results showed very low mobility reduction factors for fractured cores compared to those obtained from the un-fractured cores (about one half). The authors related this to the effect of several parameters such as the high flow velocity, low water (surfactant solution) in the fracture, and the surface structure of the fracture.

Panahi [15] showed, experimentally and numerically, the beneficial effects of foaming of CO_2 on the oil recovery of two types of cores. In the first case, only a longitudinal fracture was created in the core, while in the second core a transverse fracture was also created. His results showed that presence of foam could decrease the negative effects of the longitudinal fractures, for which Panahi reported 20% of additional oil recovery compared to the gas flooding. The presence of the transverse fracture showed negative effect, reducing the additional oil recovery to 5-10% above gas flooding. The injection rates and foam quality values are not mentioned in the paper and the reported recovery values are after 6 pore volumes of the fluid injection.

Zuta and Fjelde [16] performed a number of experiments to study the effect of foaming of CO_2 on the recovery of oil from the fractured chalk rocks. They observed that co-injection of CO_2 and a foaming agent slightly increased the oil recovery. The authors attributed the oil recovery to the combined effects of CO_2 gas itself and diffusion of the surfactant from the fracture into the matrix, which alters the rock wettability and the interfacial tensions of CO_2-oil and CO_2-surfactant solution systems enabling capillary imbibition of CO_2 gas/aqueous foaming agent solution into the matrix.

Lopera Castro et al [17] reported experiments in which the fractures were closed in two ways: by increasing the overload pressure and by injecting foam. Unfortunately the conditions of the experiments (e.g. core position, flowrates, etc.) are not clearly stated in the paper. However, they found that the fracture blockage by foam increases the recovery on average by up to 10% compared to the fracture blockage by applying pressure. The authors recommended using foam as divergent agent since it increases the oil recovery from the matrix.

Haugen et al. [18] used foam to reduce fracture transmissibility and improve the matrix sweep in highly fractured low-permeable oil-wet limestone. Gas alone or water injection recovered only 10% of initial oil in the core, most of which was the oil in the fracture network. When foam was used in the experiments, about 80% of the oil was produced. The generation of foam diverted significant amounts of fluids from fracture to matrix. They also observed that in-situ generated foam in the smooth walled fractures was weak while pre-generated foam was sufficiently strong to divert the fluids to matrix.

Moradi Tehrani [19] studied the benefits of foam in steam and gas flooding of naturally fractured reservoir using CMG-STARS. They concluded that in the case of CO_2 oil recovery is greater from matrix with foam than without. However, oil in the matrix is not displaced by CO_2 from the top of the formation as expected, but primarily by water from the bottom.

Appendix B: Apparent viscosity of foam in smooth capillary tubes

In the absence of the gravity and assuming that the surface-tension gradient has a negligible effect on the foam viscosity, one could write [9,10]:

$$\mu_f^{app} = \mu_{app}^{liq} + \mu_{app}^{def} \tag{B.1}$$

In this model it is assumed that the whole system (i.e., lamellae, wetting films and gas) move in unison with an average velocity of U. The apparent foam viscosity, μ_f^{app}, is a measure of pressure drop due to foaming of the gas. This can be estimated using the Poiseuille equation,

$$\mu_f^{app} = \frac{b^2}{12U} \nabla p_f \quad , \tag{B.2}$$

where b is the fracture aperture (thickness). The viscosity of the liquid part of the foam is

$$\mu_{app}^{liq} = (1 - f_g)\mu^{liq} \tag{B.3}$$

where f_g is the gas fraction of foam. The second term in Eq. (1) can be estimated from

$$\mu_{app}^{def} = \left[0.56 \left(\frac{3\mu^{liq} U}{\sigma} \right)^{-1/3} f_g^{1/2} \left(\frac{b}{r_B} \right)^{3/2} \right] \mu^{liq} \tag{B.4}$$

For derivation of this equation see ref. [9]. Replacing Eqs. (B.3) and (B.4) in Eq. (B.1) provides,

$$\mu_f^{app} = \left[(1 - f_g) + 0.56 \left(\frac{3\mu^{liq} U}{\sigma} \right)^{-1/3} f_g^{1/2} \left(\frac{b}{r_B} \right)^{3/2} \right] \mu^{liq} \, , \tag{B.5}$$

from which the total pressure drop in the fracture can be calculated:

$$\nabla p_f = \frac{12U}{b^2} \left[(1 - f_g) + 0.56 \left(\frac{3\mu^{liq} U}{\sigma} \right)^{-1/3} f_g^{1/2} \left(\frac{b}{r_B} \right)^{3/2} \right] \mu^{liq} \quad . \tag{B.6}$$

Yan et al. [10] performed experiments using two parallel plates to confirm this model in the fractures. We used their data and the model for the same purpose. Figure B.1 shows our calculations and Figure B.2 shows the calculations of ref. [10]. There is difference between the results. The model, based on our calculations, predicts lower apparent viscosity for foam than the measured values. The discrepancy between two calculations comes from the numerical error made by the authors of the paper [11]. This means that the assumption that the surface-tension gradient contribution to the apparent viscosity can be neglected is incorrect and the model needs modifications.

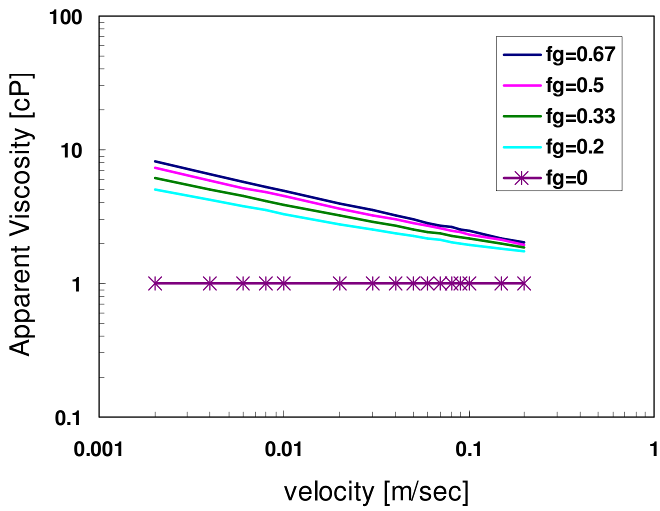

Figure B.1: Apparent foam viscosity for different foam qualities, based on Eq. (B.5). *b=0.2mm* and r_b*=0.2mm.*

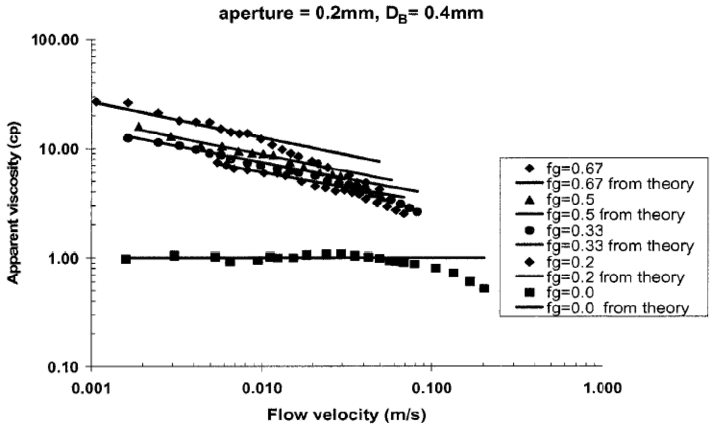

Figure B.2: Comparison of the experimental data with the theory [10]. Note that there is numerical error in the calculations and model does not predict the results correctly.

Appendix C: Simulation parameters

Table C.1: Reservoir properties

Height	60 [=] m
Width	10 [=] m
Area	300 [=] m^2
Matrix permeability	5 [=] mD
Fracture permeability	1000 [=] D
Porosity	0.32
Fracture width	1 [=] mm
Initial pressure	25 [=] bar
Initial temperature	323 [=] K
Oil-gas Corey	4.5
Gas Corey	2.1
Oil-water Corey	3.2
Water Corey	3.2
Oil-gas endpoint	1
Gas endpoint	1
Water endpoint	1
Oil endpoint	0.75

Table C.2: Fluid properties

Water density	1063 [=] kg/m^3
Water viscosity	0.6 [=] cP @ T_{res}
Oil density	726 [=] kg/m^3
Oil viscosity	2 [=]cP @ T_{res}
Gas density	6.6 [=] kg/m^3
Gas viscosity	0.012 [=]cP @ T_{res}

Table C.3: Foam parameters

MRF	$(0.1\text{-}5)\times10^6$
Fm_surf	0.000385
ep_surf	1
fm_dry (S_w^*)	0.10
ep_dry	1000
fm_oil (S_o^*) (base case)	0.20
fl_oil	0.0
ep_oil	1
Foam quality (base case)	0.99 (surface), 0.87 (reservoir)

Appendix D: Equivalent gas mobility by adjusting fracture permeability

To improve the understanding of the oil recovery mechanism, we performed a simulation in which the gas mobility in the fracture was chosen such that

$$\left(\frac{k_{frac,eff}}{\mu_{gas}}\right)_{no-foam} = \left(\frac{k_{frac}}{\mu_{foam}}\right)_{foam}$$

using the gas viscosity of 1.2×10^{-2} cP and the apparent foam viscosity of 20 cP, the effective fracture permeability should be about 600 mD to get the same mobility for the gas as in the foam-run case (MRF=5×10^5). Figure D.1 compares the oil rate and the producer pressure of this run with the foam case. The gas breakthrough in this case is delayed and therefore initially the oil production is slightly higher. Moreover, in this case the producer produces under maximum pressure drawdown until the gas breakthrough, while in the foam case the well produces always under a given gas-rate constraint. The reason becomes clear from Figure D.2 in which we show the fluid saturations at Year 3. In the foam case, the creation of foam reduces the gas mobility only and when oil or water move from the matrix to the fracture, due to the high permeability of the fracture and the gravity, they are immediately produced. Consequently, the fracture is filled with the gas only. When the fracture permeability is reduced to 600 mD the mobility of all fluids is reduced (viscous forces dominate the flow rather than the gravity forces). Therefore, the fracture contains oil, water and gas at the same time, unlike the foam situation.

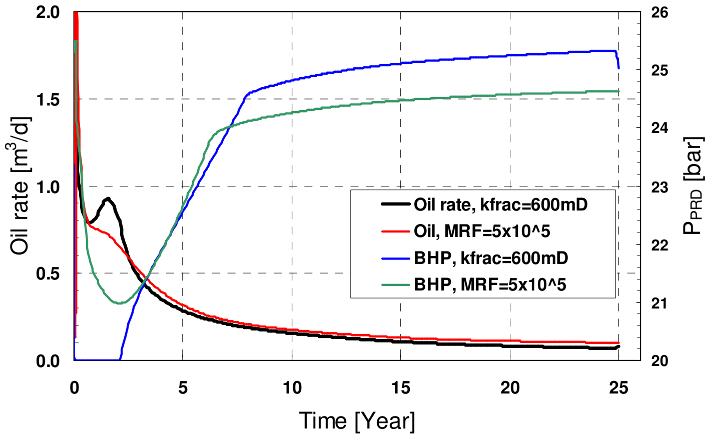

Figure D.1: Pressure and oil-rate profiles of foam with MRF=5×10^5 and the GOGD with k_{frac}=600 mD (equal gas mobilities)

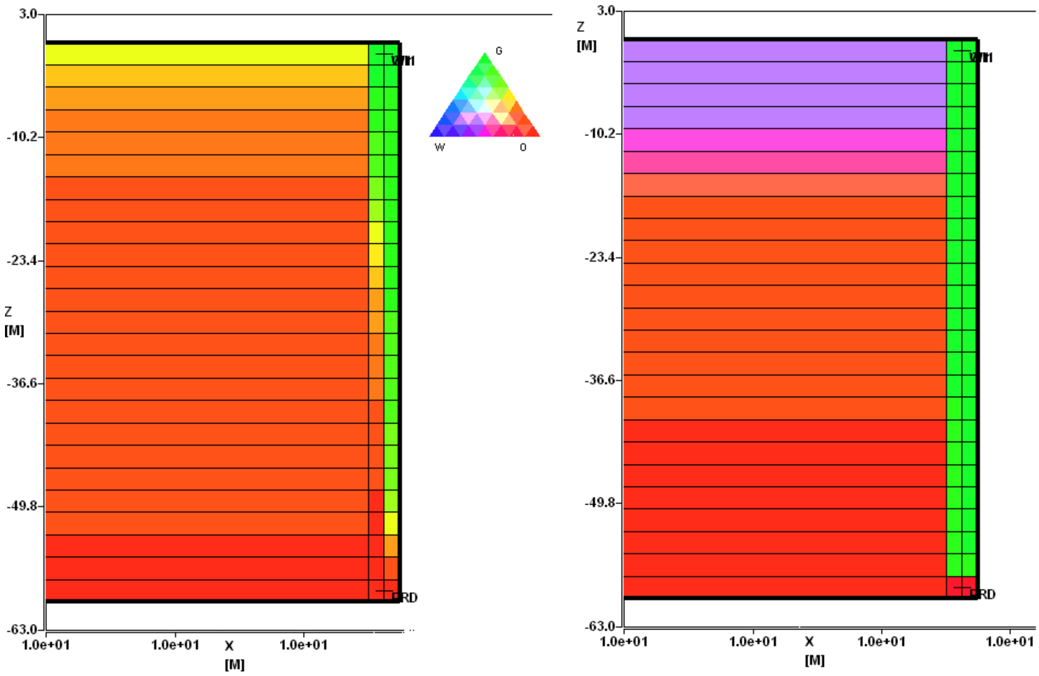

Figure D.2: Fluid saturations in the fracture for the simulation runs of Figure D.1 at t = 3 year (left: reduced k_{frac}, right: foam).