Field Application and Simulation of Foam for Gas Diversion

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ABSTRACT

Field application of foam for gas diversion was conducted in a gas condensate reservoir. The application included two years of foam injection in a single pattern, monitoring of condensate recovery in pattern producers and simulation of the process.

The primary objective of the study was to determine the effectiveness of foam in improving production response. The field, a carbonate formation with grossly varying permeability ranging between 0.1 to 20 md, had been under enriched gas drive for a number of years. Injected gas, initially nitrogen, had been gradually replaced with recycled gas. As a result, condensate yield in produced gas continued to decrease. Based on the observed gas breakthrough and somewhat adverse mobility ratio of the injected gas to the heavier in situ hydrocarbon gas, it was assumed that gas diversion from more permeable, gassed out layers could improve condensate recovery.

A single pattern, foam injection project was initiated in August of 1991. Field injectivity data collected during the first six months of the project and the gas injection history of the field, were used to construct and history match a simulation model. STARS simulator from Computer Modelling Group was used for the study. Field observed results over a two-year period were used to predict recovery from an extended project of five-year duration. Simulation was also used during the early stages of foam injection for optimization of surfactant injection.

The study showed that incremental gas condensate recovery can be obtained from foam application under appropriate mobility and heterogeneity conditions. Simulation techniques based on surfactant tracking and reduction of gas relative permeability, as used in STARS, can sufficiently model the process. Finally, inclusion of reservoir characteristics in the model at the early stages of field application can result in significant cost saving by optimizing various process parameters.

INTRODUCTION

Injected gas channeling in gas and gas condensate reservoirs, under pressure maintenance, often limits recovery to a small fraction of original fluid in place. Successful development of foam technology to control premature gas breakthrough and improve volumetric sweep efficiency could increase recovery in these classes of reservoirs. A survey of current literature shows that foam has potential for gas diversion or blockage. Specifically, recent field tests of hydrocarbon miscible^{1,2} and nitrogen³ foam injections have been reported. Injected CO₂ foams have also been employed^{4,5}, although the often liquid like density and lower surface tensions of this injected fluid can imply significant process differences. The interpretation of these results are often complicated due to (1) identification of the appropriate interval for foam application, (2) reservoir description uncertainties associated with the typically large well spacings and (3) small treatment size. Recently there has also been a trend towards employing foam as a production well GOR treatment^{6,7}. Most success in the application of foam has been for steam diversion and volumetric sweep expansion in numerous field trials⁸⁻¹². These tests are usually characterized by smaller well spacings than those encountered above. Also, the difference in temperature and pressure conditions between the two environments necessitates the development of a suitable, yet much different, process and surfactant. Since the effect of gravity override and adverse mobility in gas-foam applications is not as severe as in steam-foam applications, the primary contributing factors to improved recovery are channel blocking and improved areal sweep. A paper summarizing most of the foam field tests has recently been published¹³.

Simulations of these various field foam processes and reservoir characteristics are desirable and useful, both in terms of pretest screening and process history matching and optimization. For these purposes, the simulator should be capable of representing foam behavior on the time and length scales of the field process, as well as producing representations of complex zonal variabilities in heterogeneous sandstone and carbonate reservoirs.

In the end, the essence of field scale reservoir simulation is still to match the balance of gravity and viscous forces occurring during multiphase, multicomponent flows.

Current foam simulation models differ in their assumptions about representing the time length scales of foam texture changes, as well as the relative contributions of flowing bubbles (viscosity effect) and stationary bubbles (relative permeability effect). One class of models, often termed population balance approach, considers the dynamic interplay between foam generation and coalescence mechanisms. This approach has the advantage of demonstrating situations under which a pseudo-equilibrium balance between these rates results (the "usual" case). As well, these authors seem to imply that there exists a relatively equal balance between flowing and trapped bubbles to the observed foam resistance. A second class of models makes the further assumptions that a pseudo steady state representation is sufficient for practical purposes, and that the observed foam resistance can be attributed entirely to a relative permeability effect. It is our contention that this second approach is most practical and appropriate for foam simulation of large length and time scales in naturally heterogeneous porous media, and is employed in this paper.

The primary objective of the current study was to determine the effectiveness of foam in improving production response in a gas condensate reservoir. A more detailed process description for gas-foam application is described elsewhere. The secondary objective was to evaluate simulation techniques and their applicability to gas-foam in condensate reservoirs.

FIELD HISTORY AND PROCESS DEVELOPMENT

The field, a carbonate formation known as Smackover, with grossly varying permeabilities ranging between 0.1 to 20 md, had been under enriched gas drive for a number of years, basically to prevent condensate liquid dropout. Injected gas, initially nitrogen, had been gradually replaced with recycled gas. As a result, condensate yield in produced gas continued to decrease. The producing

wells in the central part of the field had been most affected, since they were communicating with the centrally located injection wells. Based on the observed gas breakthrough and somewhat adverse mobility ratio of the injected gas to the heavier in situ hydrocarbon gas, it was assumed that gas diversion from more permeable, gassed out layers could improve condensate recovery.

A single pattern, foam injection project was initiated in August of 1991. Field injectivity data collected during the first six months of the project and the gas injection history of the field, were used for initial tuning of the model. Simulation study was aimed at the determination of the effect of long term injection on recovery.

Standard screening tests¹⁴ were conducted for selection of a suitable surfactant. Due to high reservoir temperature, 325°F, surfactant screening was limited to C20-24 alkyl aryl sulfonate, mixed alkyl sulfonate, linear C16-18 alkyl toluene sulfonate (LTS-18), and two different alcohol ethoxy glyceryl sulfonates. From these tests, LTS-18 was selected for the field trial.

Gas injection processes may suffer from adverse mobility ratio and fluid channeling. In both cases, poor sweep efficiency results in early breakthrough and low recovery. One way to correct this situation is to use foam as a diverting agent to restrict gas channeling and improved volumetric sweep efficiency. For this field, we planned to co-inject a surfactant solution with gas in order to confine the injected gas in foam, thus preventing rapid breakthrough.

During the startup, we noted that co-injection was not possible due to relative permeability effects of water/surfactant/gas system. We chose to use SAG (surfactant alternating gas) instead. In this process, a slug of surfactant solution was injected and followed by a period of gas injection. Typically, 2,000 barrels of surfactant solution with a concentration of 5,000 (ppm) was injected in three days and was followed by 37 days of gas at an average rate of 6,000 to 7,000 MSCFD.

MODEL AND FLUID DESCRIPTIONS

The study pattern included injector number 32 and producers numbers 31, 34, 46, 47 and 64 (Figure 1). The pattern was approximated by a symmetry element of 1/8" of a 640-acre inverted five-spot with 1488 coarse and 384 fine gridblocks. Reservoir and fluid parameters assigned to the model are listed in Table 1. Due to the uncertainty in areal permeability distribution, two different cases, one homogeneous and one heterogeneous, were used to bracket production response to foam injection. Selection of high permeability zone in the areally heterogeneous model was such that the breakthrough time for the injected gas matched the field observed value¹². Permeability distribution in the vertical direction was obtained from core samples and was comparable to earlier studies. Grid and permeability distribution for the areally homogeneous case is shown in Figure 2, and forms the basis for the simulations presented here.

Formation and injected fluids were approximated by two pseudo-gas components with non compositional interaction. Because of the pressure maintenance caused by gas injection, no consideration of liquid dropout behavior was required. Two additional components, water and surfactant, were also included. Properties of water were internally provided by the model. The surfactant properties were input to the model and in some cases were modified during the history matching process. Other parameters such as surfactant adsorption and foam mobility reduction factor were obtained from early history match of the first three SAG cycles. Fluid properties are summarized in Table 1.

HISTORY MATCHING AND FOAM MODEL VALIDATION

Following the construction and initialization of the model, gas injection was started in 1983. Injection rate history was approximated during the period of 1983 through August of 1991. Reservoir model parameters were adjusted in order to match reported gas breakthrough time of March 1985. Two cases were considered, areally homogeneous and heterogeneous. Injection gas rate and gas breakthrough plots are shown on Figures 3 and 4.

The results indicated that breakthrough time was more closely matched with the heterogeneous model. Figure 5 illustrates the predicted layer dependent injection gas profiles that foam injection attempts to modify.

Surfactant properties and foam mobility reduction parameters were included during this phase (Table 1). In particular, observed injection pressure rise and decay (Figure 6) were used to match an effective foam effect. History matching continued for one WAG cycle, immediately following the gas injection period, and three subsequent SAG cycles. WAG was used for tuning of gas/water relative permeability. SAG's were used for determination of surfactant adsorption and foam mobility reduction factor. These parameters influence gas mobility, thus gas injection rate at constant injection pressure. Figure 6 illustrates a match obtained with a combination of these factors.

Focusing on this portion of the simulation allows many important aspects of field scale foam modelling to be illustrated and investigated. First, condensate behavior above liquid dropout pressure levels implies that water/gas foam behavior can be studied without the added complication of sensitivity to the presence of an oil phase. As such, this is the most ideal field foam "experiment". Second, these cyclic tests illustrate the important role that the shape of the two phase water/gas relative permeability curves in the absence of foam can have on observed foam response. Basically, these (pseudo) curves reflect the field scale gridblocked averaged flow pathways that foam is intended to modify. As such, these curves can be expected to be block size dependent in general.

The first WAG cycle indicates how much the observed pressure response in subsequent SAG cycles is due to a slug of water. The increasingly slow rise in gas injection rate with each SAG cycle illustrates the propagation of injected surfactant. Thus one aspect of a practical foam simulator is surfactant propagation modelling including adsorption levels. Note adsorption levels, and especially the approach to maximum levels, should be viewed as a pseudo-effect and possibly gridblock size dependent. This was a major reason why we

invoked a fine grid representation near the injector. Figure 8 illustrates the sensitivity seen to various adsorption levels.

Foam effects on gas mobility and flow pathways are modelled via modified relative permeability curves. The model allows to account for foam sensitivity to the different factors through a dimensionless interpolation parameter. The gas permeability used in each particular computation is obtained by interpolating between gas and foam permeability curves using the following expression:

$$FM = \left[1 + MRF \cdot \left(\frac{w_s}{w_s^{max}} \right)^{e_s} \right]^{-1}$$

which is the simplest version of possible interpolation effects¹⁵. Here

$$MRF = \frac{\Delta p_{foam}}{\Delta p_{nofoam}}$$

is the mobility reduction factor at a reference velocity, and can be viewed as a normalized pressure drop per lamella times a normalized lamella density.

Focusing on the local mobility reduction level, the equation for FM illustrates the role of increased surfactant concentration on the observed resistance to gas flow caused by foam. Again it should be expected that the parameters may be pseudo values, such that MRF and e_s may be gridblock sized dependent, due to a combination of gravity and heterogeneity. A more complete study of scaling up of foam phenomena is currently underway¹⁶, which should provide useful further insight into some of these effects. Figure 9 illustrates the sensitivity to assumed maximum mobility reduction factors MRF.

As the above figures illustrate, with even the simplest representation, various combination of factors (adsorption maximum and MRF) can be used to match the short time (first few cycle) responses. Two such combinations, (low MRF and high MRF) both of which approximately match the first few cycles observed injection pressure response, were selected for further long time implications.

SIMULATION RESULTS AND SENSITIVITIES

Simulation runs were made for both homogeneous and heterogeneous cases. The following injection scenarios were investigated:

- (I) Continued gas injection at constant rate of 10 MMSCFD
- (II) Continued gas injection at a reduced rate
- (III) SAG injection for five years, high MRF case
- (IV) SAG injection for five years, low MRF case

Each case included gas injection through August of 1991 as a base.

Case I and II

First, the effect of gas injection rate on production was investigated. Gas injection rate was lowered to 3-4 MMSCFD for five years. Production response was compared to continued gas injection at 10 MMSCFD. The results, shown on Figure 10, indicate that gas condensate production rate increases with decreased injection rate. The result can be explained by the fact that gas condensate and injected gas are in competition for being produced. When the driving force for one is decreased, the other will take over.

Case III

A comparison between continued gas injection and SAG injection was made for a five year project. SAG injection consisted of four initially matched cycles followed by a large number of simulated cycles. Each simulated cycle included 3 days of surfactant solution at 5,000 ppm concentration, followed by 37 days of gas injection for a total of 40 days. For the homogeneous case, shown on Figures 11-14, the results indicate that:

- a) Average gas injection rate is lower with SAG
- b) Produced gas condensate is higher with SAG
- c) Incremental increase is primarily due to lower gas injection. This was confirmed by comparison with a SAG injection case in which injection pressure was raised to a level equal to the gas alone case

- d) Foam propagation front advance is limited

Case IV

Lowering the effective MRF reduces the magnitude of the foam effect, but otherwise the observed response is similar. Figures 15 and 15 compare the two MRF scenarios. In particular, lowering the injected gas rate to 6.0 MMSCFD mimics the effect of foam in this case, just as 3-4 MMSCFD gas injection duplicates the high MRF foam run. Observed field performance is closer to the case IV prediction.

Similar conclusions can be drawn for the heterogeneous case¹². The magnitude of incremental gas condensate for this case, however, is larger and the advance of foam front is more rapid along the high permeability zone.

FOAM EFFECTIVENESS

Based on simulation results, it appears that foam injection is not very effective in Smackover Carbonate. The following are reasons for this finding:

- a) Foam is most effective in severely channeled formations and under adverse mobility conditions. Heterogeneity of Smackover Carbonate is apparently not severe enough to make it a good candidate for foam diversion.
- b) Limitations on injection rate result in slow down of foam propagation front to the extent that even after five years only a small fraction of the formation is contacted.
- c) Limitations caused by high surfactant adsorption levels can also inhibit foam propagation.

In general, large pattern size discriminates against a frontal advance and delaying production response. To make these latter comments more concrete, consider an idealized version of the Canadian reservoir employed in a hydrocarbon miscible foam test¹. This limestone reservoir has typical pattern spacings of 160 acres and permeabilities of the order of 25 md to 200 md. With this reservoir in mind, we have taken our previous grid and reduced gridblock size by a factor of two in both the x and y

directions, and increased all permeabilities by one order of magnitude. The same fluid description and foam process were then applied to this modified reservoir, with more promising results. However high levels of surfactant loss still cause a rapid deterioration of the foam process effectiveness.

CONCLUSIONS

Foam injection results in decreased injectivity and increased incremental gas condensate recovery. The value of this increase is estimated to be between \$1.2 MM to \$2.4 MM, depending on the duration of the project (based on an assumed \$4 per MCF of gas condensate). Additionally, reduced gas injection can result in savings of gas recycling and recompression costs.

Reduced gas injection rate alone, results in similar increase in incremental recovery for a five-year injection project, suggesting that surfactant contribution is not significant in this time period. Although reduced gas injection results in incremental gas condensate recovery, long term effect of decreased reservoir pressure and its influence on condensate dropout has to be determined, field wide.

Foam is most effective in severely channeled formations and under adverse mobility conditions. Heterogeneity of Smackover Carbonate in terms of presence of high permeability channels, is apparently not enough to respond favorably to foam diversion.

Limitations on injection rate can result in slow down of foam propagation front to the extent that even after five years, only a small fraction of the formation is contacted.

In general, large pattern size discriminates against foam (and any EOR) drive process by slowing down frontal advance and delaying production response. In these situations, foam production well treatments may be considered as a viable alternative^{6,7}.

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NOMENCLATURE

e_s	=	parameter for the influence of surfactant concentration
Δp_{foam}	=	inlet-outlet pressure difference in a reference core foam flood at reference condition
Δp_{nofoam}	=	inlet-outlet pressure difference in a reference core flood with no foam
w_s	=	surfactant concentration in mole fracture
w_s^{max}	=	maximum surfactant concentration for foam effect

TABLE 1
Formation and Fluid Properties

Formation Type	Smackover Carbonate
Permeability	0.1 - 15 (md)
Porosity	0.12 (%PV)
Thickness	44 (ft)
Depth	18,500 (ft)
Pressure, Initial	9,200 (psig)
Pressure, Current	5,500 (psig)
Temperature	325 (F)
Injected Fluid, MW	19.6 (lb/lb mole)
Formation Fluid, MW	58 (lb/lb mole)
Surfactant and Foam Properties	
oil/water K value	0.0
surfactant half life	∞
injected surfactant concentration	1.875E-4 (mole fraction)
maximum adsorption levels	0.004 ; 0.008 ; 0.016 (lb-mole/cu ft pv)
mobility reduction factor, MRF	2.0 ; 4.0 ; 8.0
max surfactant concentration, W_{sm}	1.875E-4
exponents	1.0

Figure 1
Saddlehorn Gas Diversion Project

Figure 2
Permeability Distribution for Areal Homogeneous Case

Figure 3
Daily Injection for Injector No. 32

Figure 4
Injected Gas Breakthrough Areal Homogeneous
Versus Heterogeneous, with Field Data

Figure 5
Predicted Injection Gas Profiles Before Foam Treatment (at 1095 days)

Figure 6
Foam Gas Diversion Project

Figure 7
Comparison Between Field and Predicted
Injection Rates for 1 WAG and 3 SAG Cycles

Figure 8
Effect of Surfactant Adsorption Levels on Injection Rates

Figure 9
Effect of Mobility Reduction Factor on Injection Rates

Figure 10
Comparison of Gas Injection Rate on Condensate Produced

Figure 11
Comparison of High Rate Gas Versus Foam Injection

Figure 12
Comparison of High Rate Gas Versus Foam on Condensate Produced

Figure 15
Comparison of High Versus Low MRF on Injection Rates

Figure 13
Comparison of Low Rate Gas Versus Foam on Condensate Produced

Figure 16
Comparison of High Versus Low MRF on Condensate Produced

Figure 14
Surfactant Propagation Limited by Adsorption