# *Foam Pilot Evaluations for the Snorre Field*

**Part 2: Numerical Simulations and Economical Evaluations**

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## ABSTRACT

This paper is the second in a series of papers dealing with various aspects of the hydrocarbon gas-foam pilot project planned for the Snorre Field. The first paper summarized the project plans and detailed the laboratory work leading to the selection of a surfactant for the field test.

An evaluation of improved oil recovery by foam treatment, process uncertainty, and some preliminary economic estimates are presented in this paper. The evaluation has been based on numerical simulations, the above mentioned laboratory tests, field experience from foam treatments, and general process considerations. The simulations have included foam-assisted WAG (injector treatment), related to the WAG pilot area in the Snorre Field, and foam treatment in a production well (P-29), the candidate for the field test.

Reduction in GOR, improvement in oil rate and ultimate oil recovery make foam treatment attractive for the Snorre Field. The cumulative oil production improvement over WAG injection by application of a Surfactant Alternating Gas (SAG) type process is estimated to be 3-7% (after a 10-year production period) if foam with a mobility reduction factor (MRF) of 50-100 is generated in the reservoir. Foam treatment of the producer P-29 can prevent gas breakthrough and extend production life of the well. Conservative estimates for a successful foam producer treatment improve the oil recovery by 90000 $Sm^3$ with a cost of less than 1 USD/bbl.

## INTRODUCTION

Foam application can be effective for improving the volumetric sweep in gas injection processes, and thereby increasing the oil recovery. While gas may offer high microscopic sweep efficiency, the high mobility and low density of gas introduces problems like fingering and gravity override, which give poor sweep efficiency in the reservoir in the form of bypassed oil zones. A reduction of the gas mobility by foam may counteract both viscous fingering and gravity segregation effects. Moreover, where gas zones extend to a production well, a reduction of gas mobility by application of foam in the proximity of the well may reduce its gas-oil ratio.

In the Statfjord Formation, the possibility of a foam pilot project[1] in conjunction with the Water-Alternating-Gas (WAG) injection programme[2,3] is being examined. The Statfjord Formation is characterised by high permeability contrasts and limited interlayer communications. An injector foam treatment will reduce flow of gas segregated to the top of the reservoir. The objective will then be to increase oil production by reducing the gas mobility in thief zones and diverting gas into unswept oil zones, and thereby also reduce the gas-oil ratio on the production side.

An introductory study carried out in 1993 demonstrated the feasibility of gas diversion by foam in a physical 2D three-layer flow model reflecting the essential features of the Statfjord Formation.[4] Placement of a surfactant slug and subsequent foam generation in the swept high permeable top layer was successfully demonstrated and gave efficient injectant diversion into the low permeable layers, resulting in complete sweep of the reservoir model by continued WAG. The process, termed *SAGA (Surfactant Alternating Gas Ameliorated) Injection,* indicated significant potential of improved oil recovery by a suite of simplified reservoir simulations using a cross section from the Statfjord Formation.[4]

However, a large scale field test of SAG injection in the Snorre WAG pilot area with interwell distances of 700-1500 meters has been considered to involve too high economic risk and be too time consuming with respect to the necessary data recording, for a first step pilot. Therefore, to reduce the risk (cost and time) a production well test has been recommended (small amounts of surfactants are required compared to an injector treatment). A pilot in a production well is considered to be an important test of foam application in Snorre and it is expected to provide useful information also for an injection treatment.[1]

Three production wells in the WAG pilot area, P-13, P-18 and P-29, have been considered as potential candidates for a foam test.[1] The P-18 well has already experienced a significant gas breakthrough and was shut in for a continuous period of time due to the gas handling restrictions on the platform.[3] This well is now a subject to traditional zonal isolation of the upper perforation intervals producing gas. The P-29 well is believed to be in the beginning of the gas breakthrough due to the slowly increasing production GOR in the well.[3] Two explanations for the gas breakthrough problem exist today: (1) gas cusping and coning from the artificial gas cap, which is forming in the WAG pilot area; (2) gas breakthrough from the downdip WAG injector along the high permeable thief zone in the Upper Statfjord Formation. Since the major gas breakthrough is experienced so far only in the P-18 well, situated in the upper structure at a longer distance from injectors than the other wells, the first concept is considered most valid.

Gas breakthrough development is expected in P-29 during the first half of 1995. The gas is believed to hit the well in the top perforations, i.e. the thin S10 subzone.[1]

Foam generation and foam propagation in a reservoir is difficult to model accurately by numerical simulators as foam in porous media involve complicated physical processes. Therefore, the *SAGA Injection* flooding experiments were simulated. At an early stage of the foam program for Snorre it was felt important to check the validity of the empirical foam simulator STARS by matching a well defined, multidimensional laboratory system. Successful matching was obtained for WAG injection before and after foam treatment in the physical 2D three-layer flow model. The simulator captured the characteristic features of the foam process, including surfactant slug placement, foam generation, and diversion of injected fluids.[5]

In this paper, application of foam to improve overall WAG injection performance in the Snorre Field has been investigated; foam treatment for injector as well as for producer has been studied.

A cross-sectional model of the Statfjord Formation in the Snorre Field, covering the WAG pilot area, has been used for the potential evaluation and process prediction study. Sensitivities to various fluid and reservoir parameters have been investigated. A sector radial model and a 3D WAG pilot area model were used to simulate and design foam treatment in a production well (P-29). A 3D cartesian model covering the WAG pilot area was utilized for estimations of the potential for improved oil recovery from the producer well foam treatment in P-29. The field scale reservoir simulators, STARS and ECLIPSE, incorporating an empirical foam description, were used in the simulation studies.

Based on the simulations and experimental results, some estimates of process economics have been made.

## NUMERICAL SIMULATIONS

Three simulation studies have been carried out:

1) Evaluation of foam potential for downdip WAG improvement in the Statfjord Formation (foam-assisted WAG)
2) Near well simulation for designing a foam test in well P-29 (producer)
3) Evaluation of foam potential for producer treatment (field scale foam simulations)

The simulators, STARS and ECLIPSE 100, were used in these studies. STARS was used in studies 1 and 2, while ECLIPSE was used in study 3.

STARS is a commercial reservoir simulator developed by the Computer Modelling Group in Canada. It is a fully-featured field and laboratory scale simulator with an empirical foam option. A short description of STARS is given in *Ref 6.*

ECLIPSE 100 is a black oil simulator, which at the start of this study did not contain any option for modelling foam. As a consequence of this, foam is modelled by modifying gas viscosity in a defined region. Hence, only the effect of the foam is modelled. The modelling of the generation and propagation of foam was performed using STARS' empirical foam model.

A summary of the simulation models used in the studies is given below.

### Foam-Assisted WAG Model

A two dimensional grid with 15 grid cells in the x-direction and 14 grid cells in the z-direction was used in this study. The grid was created by extracting a cross section from the WAG pilot area in the Statfjord Formation. Figure 1 gives a geometrical representation of this grid. The production well is positioned in block 12 and the injection well in block 3. The wells are vertical and are perforated in all active layers.

The grid has a varying x-dimension with an average of 129 m, and a z-dimension varying from one grid cell to another through all 14 layers. A y-dimension of 1000 m was used.

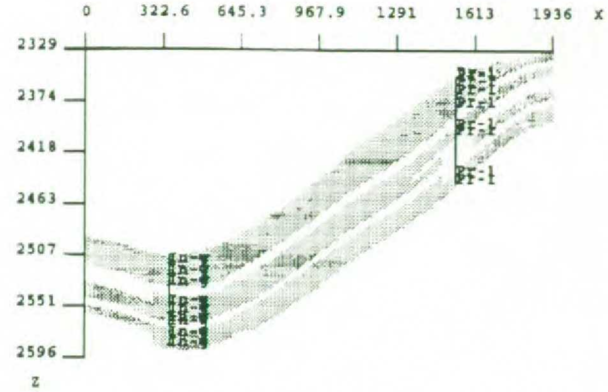


*Figure 1. A 2D (x-z direction) grid representing the WAG pilot area. (The white color reflects the shale barriers in layers 6 and 11).*

Layer 6 is a tight barrier along the entire cross section. Layer 11 is a tight barrier through most of the cross section except in the area around the production well. These two barriers divide the reservoir into three sections, which do not communicate with each other, the Upper Statfjord, the Lower Statfjord, upper member and the Lower Statfjord, lower member:

- Upper Statfjord with very high permeabilities, ranging from 1000 to 4000 mD.
- Lower Statfjord, upper member with lower permeabilities, ranging from 100 to 300 mD.
- Lower Statfjord, lower member with a high permeability (800 mD) upper part and a low permeability lower part with permeabilities in the range of 10-20 mD.

Layer averages of the reservoir parameters used in the model are summarised in Table 1.

The fluid system, representing the Snorre reservoir fluid properties, were described by two aqueous components (water and surfactant) and three oleic pseudo components (C1, C4 and C10). Both the production well and the injection well operate at a rate of 5000 $Sm^3/d$, with a maximum bottom hole pressure of 428 bar in the injector and a minimum bottom hole pressure of 180 bar in the producer. This rate was scaled according to the STOOIP in the model, hence making it representative for the Snorre Field.

*Table 1. 14 layer reservoir model*

| | Statfiord Reservoir | | 14 Layer Model | Thickness (m) | Porosity | Net/ Gross | Perm. (mD) |
|---|---|---|---|---|---|---|---|
| | Res. Zone | Res. Subzone | | | | | |
| Upper Statfjord | S1 | S10 | 1 | 1.9 | 0.259 | 0.329 | 3 734 |
| | | S11 | 2 | 4.2 | 0.225 | 0.605 | 1 875 |
| | | S12 | 3 | 7.2 | 0.256 | 0.845 | 3 435 |
| | S2 | S20 | 4 | 9.4 | 0.254 | 0.712 | 3 986 |
| | | S21 | 5 | 8.7 | 0.230 | 0.933 | 933 |
| Lower St.fj. um | S3 | S30 | 6 | 8.1 | 0.224 | 0 | 112 |
| | | S31 | 7 | 7.1 | 0.236 | 0.502 | 168 |
| | | S32 | 8 | 6.0 | 0.248 | 0.731 | 279 |
| | | S33 | 9 | 5.4 | 0.224 | 0.396 | 100 |
| | | S34 | 10 | 5.0 | 0.216 | 0.374 | 73 |
| Lower St.fj. lm | S4 | S40 | 11 | 7.0 | 0.200 | 0.042 | 93 |
| | | S41 | 12 | 7.4 | 0.223 | 0.382 | 804 |
| | | S42 | 13 | 9.8 | 0.167 | 0.284 | 10 |
| | | S43 | 14 | 3.9 | 0.176 | 0.545 | 21 |

## Near Well Producer Model (P-29)

A near well STARS simulation model of the P-29 well was built in order to evaluate gas breakthrough and foam treatment potential in the well. The model used was a half-circle radial model of three $60^{o}$ segments with 700 meters radius reflecting the drainage area of the well. The model has a $9.3^{o}$ formation dip as in the near well area. The grid blocks near the well were refined to the size of 1 meter.

The core and log data of the P-29 well were used to specify reservoir properties in the model. Three sealing layers are identified in the well area: S11M, S31M and S40-41M shales, Table 2. The S11M barrier is not continuous in the Upper Statfjord Formation. In the P-29 area the S11M is believed to have a lateral extend of several hundred meters around the well. Porosities, permeabilities and perforation intervals in the well model are given in Table 2. The constructed model and perforation intervals were calibrated against spinner survey/production logging tool (PLT) measurements.

The scenario with gas breakthrough, occurring as a result of cusping and coning from the artificial gas cap, was modelled with the help of fake wells, imitating artificial gas cap expansion and downdip WAG injection. The model was also calibrated to duplicate the 3D WAG pilot predictions on the production GOR development in the P-29 well (see below)

*Table 2. Production well P-29 model*

| Nº grid block | Sand | Gross [m] | Poro-sity | Kh aritm. [mD] | Kv geom. [mD] | Per-fora-tion P-29 |
|---|---|---|---|---|---|---|
| 1 | S10S | 0.8 | 0.303 | 8596 | 4298 | XXX |
| 2 | | 0.8 | | | | XXX |
| 3 | | 0.8 | | | | XXX |
| 4 | S11M | 5.1 | 0 | 301 | 30 | |
| 5 | S11S | 1.75 | 0.191 | 537 | 268 | XXX |
| 6 | | 1.75 | | | | XXX |
| 7 | S12S | 1.55 | 0.273 | 8692 | 3612 | XXX |
| 8 | | 8.55 | | | | |
| | S20M | 0 | | | | |
| 9 | S20S | 7.7 | 0.287 | 8373 | 4909 | |
| 10 | S21M | 0.8 | 0.286 | 6353 | 635 | |
| 11 | S21S | 5.2 | 0.284 | 6032 | 2187 | |
| 12 | | 5.2 | | | | |
| 13 | S30M | 9.6 | 0.051 | 874 | 36 | |
| 14 | S31M | 1.8 | 0 | | | |
| 15 | S31S | 2.4 | 0.135 | 835 | 101 | XXX |
| 16 | S32M | 1.4 | 0.016 | 5 | 12 | XXX |
| 17 | S32S | 2.4 | 0.261 | 494 | 657 | XXX |
| 18 | S33M | 8.5 | 0.004 | 5 | 5 | XXX |
| 19 | S34M | 5.4 | 0.025 | 20 | 134 | XXX |
| 20 | S40M | 5.2 | 0 | | | |
| | S41M | 0.7 | 0 | | | |
| 21 | S41S | 5.9 | 0.225 | 687 | 263 | XXX |

## Pilot Area Model (P-29)

The 3D simulation model used for the field scale foam producer simulation is a sector of the full field model of the Statfjord Formation. The sector covers the southern part of the Central Fault Block (CFB) including the wells P-25, P-28, P-13, P-18, and P-29 (WAG pilot area) (*cf.* Figure 1 in *Ref 1).* The model contains 20 grid blocks in the x-direction, 19 in the y-direction and 37 in the z-direction. The top layers have been refined in z-direction to better model flood of gravity segregated gas. The simulation grid, excluding the local refinement, is shown in Figure 2. A constraint in gas production, which limits the gas rate for the sector model to 850.000 $Sm^3/d$, is modelled. This is a rough estimate reflecting the gas handling limitations from the field.[3]

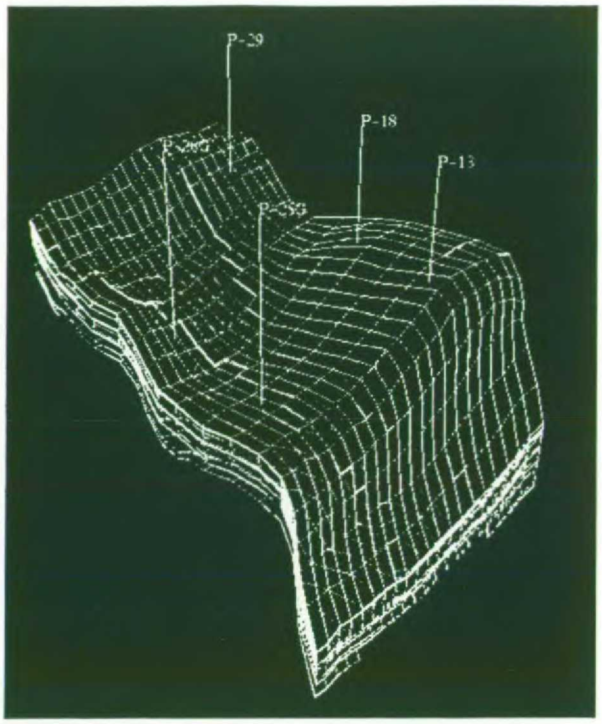


*Figure 2. Simulation grid for field scale foam simulations (producer treatment).*

# RESULTS AND DISCUSSION

## Foam-Assisted WAG

A summary of some of the simulation runs are given in Table 3. Two base cases were established; a WAG flooding case and a SAG flooding case. The WAG flooding case was used as a reference for the evaluation of the potential for improved oil recovery by foam treatment. For the WAG simulation an initial water injection period of 180 days has been used, followed by gas and water cycles of 90 days each. The simulations were run for 10 years.

For the foam flooding base case the WAG injection process was modified by including a cycle of SAG injection (90 days 1.5 wt% surfactant solution followed by 90 days gas injection) just after gas breakthrough. Both SAG injection (surfactant alternating gas) and co-injection (simultaneous injection of surfactant solution and gas) were investigated for foam generation. No significant difference was observed in the production data (oil recovery and GOR) for these two types of processes. The data below are therefore referred only to the SAG process.

<u>Mobility reduction factor (MRF).</u> The gas mobility reduction factor is a key parameter for any foam process. Four simulation cases with foam generated in the SAG type injection process, reducing gas mobility by a factor of 50, 100, 500 and 1000 are shown in Figure 3. (Gas mobility reduction factors up to 7000 were observed for $C_{16}AOS$ and $C_{14/16}AOS$ in foam coreflood experiments at Snorre reservoir conditions[1]).

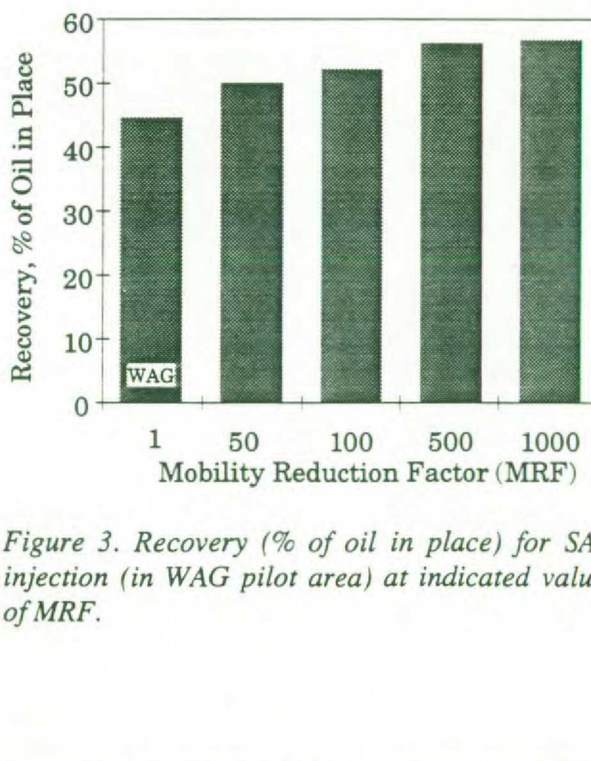


*Figure 3. Recovery (% of oil in place) for SAG injection (in WAG pilot area) at indicated values of MRF.*

| Process | Run name | MRF | Surf. slug [days] | Surf. vol inj. (Vs) [tons]* | Surf. vol back prod. [$Sm^3$] | Cum. oil prod. [$10^6Sm^3$] | Extra oil prod (Voe) [$10^3Sm^3$] | Oil incr. [%] | Es [$Sm^3$]/[$Sm^3$] | Ec [USD/[bbl]** | Eu [USD/[USD] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| WAG | 1 | | - | - | - | 6.75 | | 0 | - | - | - |
| SAG | 2 | 50 | 90 | 7784 | 529 | 7.56 | 804 | 11.9 | 103 | 7.70 | 1.94 |
| | 3 | 50 | 10 | 865 | 2 | 6.86 | 106 | 1.6 | 123 | 6.49 | 2.32 |
| | 4 | 100 | 5 | 432 | 1 | 7.24 | 488 | 7.2 | 1129 | 0.70 | 21.30 |
| | 5 | 100 | 30 | 2295 | 14 | 7.35 | 593 | 8.8 | 258 | 3.07 | 4.87 |
| | 6 | 500 | 90 | 7784 | 765 | 8.72 | 1963 | 29.1 | 252 | 3.15 | 4.76 |
| | 7 | 1000 | 10 | 865 | 1 | 7.66 | 910 | 13.5 | 1052 | 0.76 | 19.85 |

**) Calculated as 100% surfactant of density 1000 kg/$m^3$ **) 1barrel = 0.159* $Sm^3$

*Table 3. Economic estimates for SAG injection cases (Cross section model STOOIP = 15.13 x $10^6$ $Sm^3$; Surfactant conc. = 1.5 wt%; Cumulative production data after ten years.)*

The oil production improvement over WAG by placement of foam with MRF values of 50 or higher is considerable. The same is true for the control of GOR, Figure 4. A high MRF foam can cause the reservoir to produce at original gas oil solution GOR for an extended period of time. Gas breakthrough may be prevented for 1-2 years. However, this improvement can diminish significantly depending on foam critical parameters such as surfactant adsorption and surfactant volume.

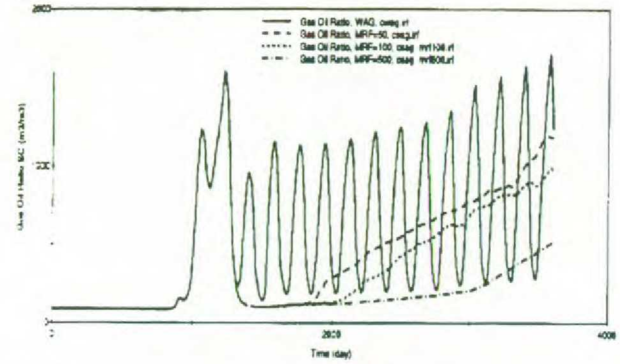

*Figure 4. Production GOR - Effect of foam MRF*

*Surfactant adsorption.* The retention and loss of chemicals *in situ* is a key factor which can limit the implementation and success of an injector foam treatment. The surfactant volumes needed in order to create an effective and sizeable gas blockage may be crucial for economic soundness of the project. Therefore, it is important to have simulated scenarios with reasonable and extreme surfactant conditions, in order to have a measure of uncertainty in possible process efficiency. The SAG process is very sensitive to the surfactant adsorption. The increase of surfactant adsorption by a factor of ten, from 0.25 up to 2.5 mg of surfactant per gram of rock (from about 0.5 up to 5 kg/m$^3$) decreases the efficiency of the foam treatment in the same order of magnitude. A surfactant adsorption level of 0.8-0.9 mg/g rock was found for $C_{16}$AOS and $C_{14/16}$AOS in Snorre rock. A MRF of 500, using the adsorption of 0.8 mg/g, gives a high efficiency improvement, corresponding to 7.8% of model STOOIP.

*Surfactant volume.* The amount of active surfactant present in the reservoir is highly affected by the level of surfactant retention *in situ*. The surfactant should be supplied in a sufficient volume to generate foam with a desired effective MRF value. The effects of varying surfactant volume were studied in three ways: (1) by increasing the surfactant concentration, maintaining the same slug size and MRF; (2) by shortening the surfactant injection period to the last 30 days of a 90-day water half-cycle, maintaining the same concentration and MRF; and finally (3) by injecting a higher-concentration slug for only 10 days capable of making a very strong foam with a MRF of 500. The first comparison increased oil recovery only from 52.2% to 52.8% of model STOOIP when surfactant concentration was increased from 1.5 to 2.0 wt-% (MRF=100). If this increased surfactant concentration allows to generate a stronger foam (MRF increased from 100 to 500), it would increase the recovery significantly, from 52.8% to 58.6% recovery of STOOIP. Recovery factors for cases 2 and 3 above are summarized in Figure 5.

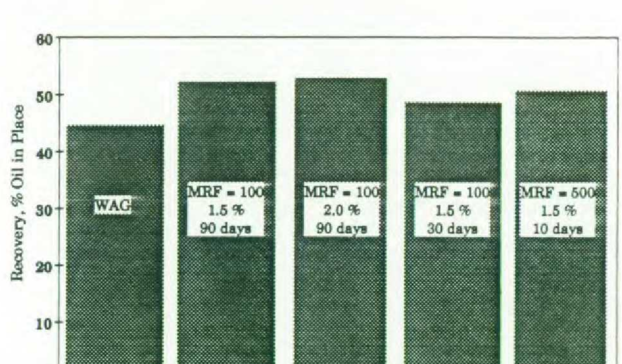


*Figure 5. Recovery (% of oil in place) for SAG injection at indicated surfactant volumes injected.*

*Timing of foam placement.* No significant difference in the cumulative oil production data concerning timing for surfactant injection was observed in the simulations, Figure 6. Placement of foam relatively late after gas breakthrough increases the volume of surfactant solution contacted by gas. However, oil production does not increase in such a case, because after gas breakthrough the reservoir pressure may drop below the minimum miscibility pressure, MMP, resulting in a reduced microscopic sweep efficiency.

Injection of surfactant solution in three smaller slugs alternated by gas did not give significant improvement in oil production, as might have been expected. The intention of the smaller slug injection was to estimate a possible improvement in foam placement and sweep efficiency, due to the extension of the mixing zone.

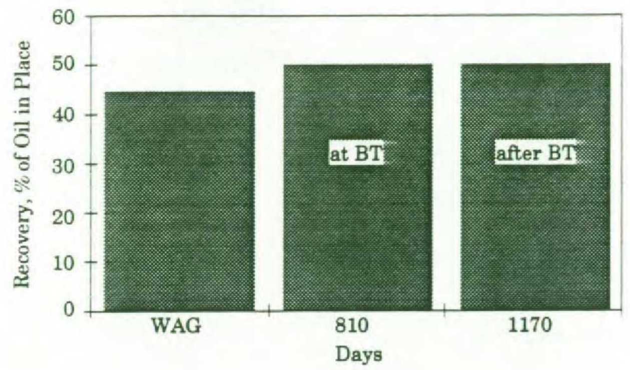


*Figure 6. Recovery (% of oil in place) for different timing of SAG injection.*

Based on results shown in Table 3 and Figures 3-6, a high MRF foam is needed to get a profitable oil recovery. The design of an optimal foam application include surfactant volume optimisation (surfactant slug size, surfactant concentration) enough to satisfy adsorption and retention and still give a high oil recovery.

## Near Well Simulations (P-29)

The P-29 well is experiencing a slowly increasing production GOR.[3] The well is believed to be in the beginning of gas breakthrough provoked by gas cusping and coning from the artificial gas cap, which is forming in the WAG pilot area.

The foam treatment in the well has been modelled as a local treatment in the 2.4 meters thick S10S sand with lower perforation intervals temporary isolated. After the foam treatment, the plugging packer is removed.[1] The objectives of the foam treatment simulations are:

- To estimate surfactant amount and concentration sensitivity
- To compare surfactant slug injection with foam co-injection

*Surfactant volume*. The surfactant propagation radius for 100 $Sm^3$ of 1 wt % surfactant solution is in the range of 15-20 meters around the well bore. Due to the high adsorption level of Snorre rock, the foam blocking effect is very sensitive to the amount of surfactant injected in order to satisfy adsorption. Figure 7 shows that placement of 200 $Sm^3$ surfactant solution (1 wt%), for generation of a 1000 MRF foam *in situ*, delays the gas breakthrough with almost 200 days and reduces well's gas production by $143.9 \cdot 10^6$ $Sm^3$.

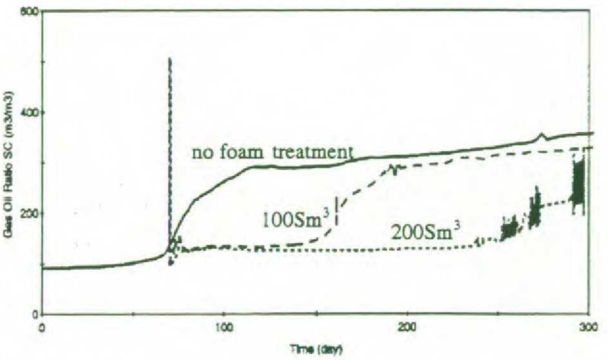


*Figure 7. Production well (P-29) foam treatment - Surfactant amount effect.*

*Foam co-injection versus surfactant/gas slug injection*. The foam injection strategy includes both alternate slugs of surfactant solution and field gas as well as co-injection.[1] Foam co-injection simulation showed a significant improvement in foam effect in comparison to a single surfactant slug placement, Figure 8. The duration of foam blocking was two times prolonged when 100 $Sm^3$ surfactant solution (1 wt%) was used for foam generation in the co-injection mode.

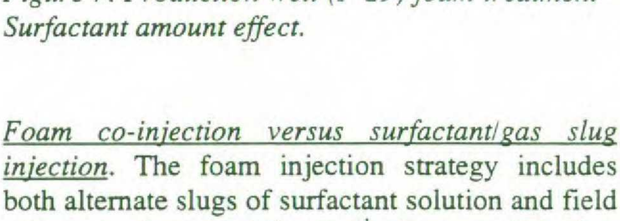


*Figure 8. Foam co-injection versus slug injection with foam generation in-situ.*

The P-29 well model will be further tuned by measured data (PLT, production GOR) and used for evaluation of different foam placement scenarios, gas breakthrough from the injector, sensitivity simulations (MRF, surfactantant concentration, oil tolerance etc.) and pilot history matching.

## Field Scale Simulation

This study was initiated to assess the potential for improvement and accelerated oil production from a field pilot foam treatment of the producer P-29. Table 4 summarizes the simulations for producer treatement of P-29.

*Oil recovery potential*. Figure 9 shows the increased oil production during the life time of the foam plug. This increased production is partly from improved sweep by the gas, and partly from the fact that a lower well GOR will allow for higher oil production due to the gas handling limitation of the Snorre Field. Some of the gas will build up behind the foam plug. This gas will be produced as the foam degrades. Here, the foam degrades 100% after 6 months. (Foam is modelled with 100% strength for half a year and then the foam disappears). A more realistic approach would be a more gradual degradation of the foam. A gradual degradation from 4 to 8 months would propably have the same net impact on production profiles as the abrupt degradation modelled here.

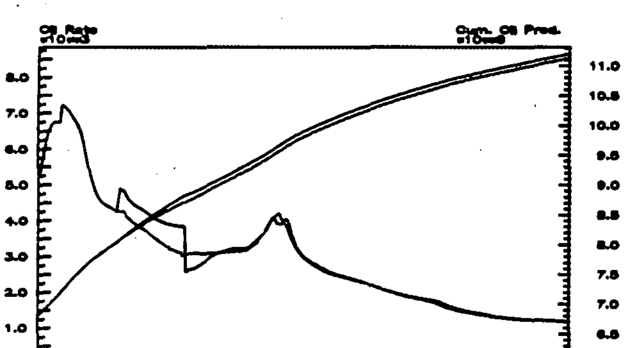

*Figure 9. Oil production profiles for foam treatment in producer P-29. The smooth rate curve and the lowermost cumulative curve represents the WAG case with no foam treatment.*

The reduction in GOR during the foam period causes an increase in GOR after the foam has been totally degraded (Fig. 9). A foam treatment in a producer as this should therefore mainly be considered a method for accelerated oil recovery, but also as enhanced oil recovery (see below). A rough estimate for this "base case" simulation gives an increased oil production of 90.000 $Sm^3$.

*Mobility reduction factor (MRF).* Simulations show that the potential is very sensitive to the reduction in gas mobility. Figure 10 shows performance of the well P-29 and the field performance as the mobility reduction factor is altered.

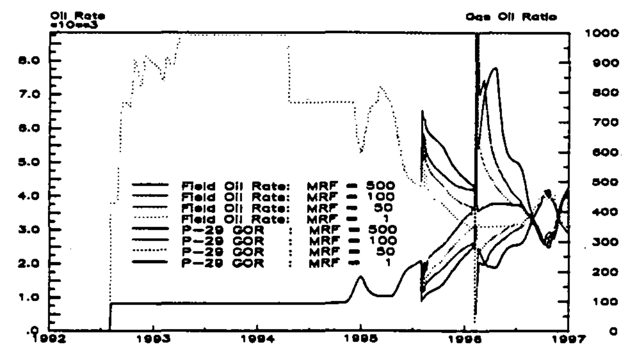


*Figure 10. Effect of mobility reduction factor on field oil production and well GOR. The spikes at the beginning and at the end of the foam treatment period are numerical artefacts from switching between global and local grids. These effects should be subtracted from the picture. The depth of the treatment is 20m for these runs.*

*Timing of foam placement*. Timing of the treatment shows to be very important. Figure 11 shows the effects of the same foam treatment conducted at three different times. If foam is placed in the S10 subzone relatively soon after gas breakthrough, the simulations show that there is a great potential for accelerated recovery of oil ('early treatment', *cf.* also run 5,6 and 7 in Table

*Table 4. Producer treatment of P-29 (field scale simulations).*

| Run name | MRF | Depth | Additional oil after 6 mths. | Additional oil after 17 mths. | Comments |
|---|---|---|---|---|---|
| 1 | 1 | 0 | 0 | 0 | Base Case WAG run |
| 2 | 50 | 20 m | $106 \cdot 10^3 Sm^3$ | $62 \cdot 10^3 Sm^3$ | MRF sensitivity |
| 3 | 100 | 20 m | $174 \cdot 10^3 Sm^3$ | $83 \cdot 10^3 Sm^3$ | MRF sensitivity |
| 4 | 500 | 20 m | $275 \cdot 10^3 Sm^3$ | $110 \cdot 10^3 Sm^3$ | MRF sensitivity |
| 5 | 100 | 10 m | $107 \cdot 10^3 Sm^3$ | $90 \cdot 10^3 Sm^3$ | Treatment August 1st 1995 |
| 6 | 100 | 10 m | $123 \cdot 10^3 Sm^3$ | $92 \cdot 10^3 Sm^3$ | Treatment February 1st 1996 |
| 7 | 100 | 10 m | $89 \cdot 10^3 Sm^3$ | $63 \cdot 10^3 Sm^3$ | Treatment August 1st 1996 |

4). This is partly due to the constraint on the Snorre platform regarding gas handling capacity.

If the foam treatment in S10 is conducted after a breakthrough of free gas in the lower perforations, the effect of the treatment will be limited ('late treatment', Figure 11).

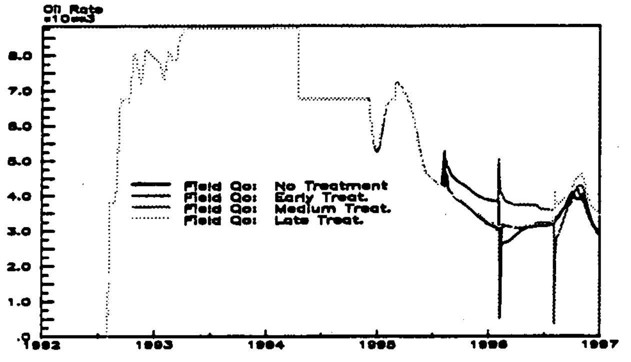


*Figure 11. Effect of timing of foam treatment on oil production rate.*

Production rates after 17 months are nearly identical for wag and foam runs (*cf.* Figure 10). This indicates that the additional recovery at this stage possibly may be regarded as enhanced recovery from the foam treatment. This is confirmed by letting the simulations continue for 10 years. The difference in total oil production between foam and wag is almost identical from 17 months to 10 years. Shut in criteria, production strategy etc. will of course influence the ultimate recoveries. However, the indications that a foam treatment in a producer will give enhanced oil recovery are quite strong.

# ECONOMIC ESTIMATES

Based on the field simulations some preliminary cost estimates have been done both for an injector foam treatment and for a producer treatment.

Foam-assisted WAG. Three simple evaluation criteria, surfactant volumetric efficiency, $E_S$, cost efficiency, $E_C$, and undiscounted economic efficiency, $E_u$, are defined:

$$E_S = V_{oe}/V_s \quad (1)$$

$$E_C = V_S C_S / V_{oe} \quad (2)$$

$$E_u = E_S C_o / C_S \quad (3)$$

where $V_{oe}$ is volume of incremental oil (over WAG) due to foam treatment, $V_S$ is surfactant volume injected, $C_S$ is the surfactant's unit cost, and $C_o$ is the oil price.

For simplicity, surfactant prices may be given "as injected" to include all costs. The economic values were calculated with an oil price of 15 USD/bbl and roughly estimated surfactant cost of 5 USD/kg at well site.

The economic estimates listed in Table 3 show that improvement in the cumulative oil production by application of the 50 MRF foam (weak foam), given for two different slug sizes (run 1 and 2), allows to achieve a good surfactant volumetric efficiency ($E_S$) of 100-120 $Sm^3/Sm^3$. The cost efficiency ($E_C$) in these cases is in the range of 6-8 USD/bbl of extra oil, corresponding to an undiscounted economic efficiency ($E_u$) of 2-2.5 USD/USD.

A strong foam (MRF in the range of 100-500 or higher) results in very favourable economic estimates with surfactant volumetric efficiency of 250-1000 $Sm^3$ of extra oil per $Sm^3$ of surfactant, cost efficiency of 0.7-3 USD per barrel of extra oil, and undiscounted economic efficiency of 5-20 USD/USD.

Field Scale Foam Simulations (Producer). The simulations show that a realistic estimate for additional oil from a foam treatment of the producer P-29 is 90.000 $Sm^3$. This gives a gross revenue of approximately 9 million USD. Costs related to a field pilot based on use of flexible hoses and pipes, utilizing 5 tons of chemicals, is estimated to be in range around 400.000 USD. This estimate is based on previous experience from the North Sea. Costs include engineering, platform hook-up, setting plug, logging and chemicals costs. From these rough estimates it can be concluded that a successful pilot will produce extra oil to a price of less than 1 USD/bbl.

# CONCLUSIONS

1. SAG injection for foam-assisted WAG in the Statfjord Formation has been shown by simulations, to be an effective strategy for improving sweep efficiency. Reduction in GOR

and increase in the ultimate oil recovery are the main advantages. The realistic cumulative oil production improvement over WAG injection by application of a SAG type process is estimated to be 3-7% (after a 10 year production period) if foam with a mobility reduction factor (MRF) of 50-100 is generated in the reservoir. MRF, surfactant adsorption, volume of surfactant, foam stability and its oil tolerance are parameters determining the efficiency of the foam process.

2. Near well simulations indicated a good potential for foam treatment to prevent gas breakthrough from the artificial gas cap into the P-29 well. If two tons of aqueous $C_{14/16}$AOS surfactant are used to generate a strong blocking foam of 1000 MRF, the gas breakthrough in the well could be prevented for more than three months.

3. Field scale simulations related to producer P-29 show great economic potential. Conservative estimates for a successful foam treatment indicated improvement in the oil recovery by 90000 $Sm^3$ with a cost of less than 1 USD/bbl. If foam is placed in subzone S10 (uppermost reservoir zone) there is a great potential for accelerated oil recovery.

4. The improved oil recovery potential by foam treatment in an injector is larger than in a producer. However, the cost per barrel extra oil recovered for a producer treatment is lower than for an injector treatment.

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