045 WATER SHUT-OFF BY DISPROPORTIONAL REDUCING GEL — A CASE STUDY

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ABSTRACT

Applications of disproportional permeability reducing (DPR) gel is discussed in this paper.

An extensive field simulation study revealed that the potential for DPR gel is dependent both on reservoir characteristics and production profile along wellbore.

A key observation is that DPR gel causes water saturation build-up in the treated zone to accomodate the fractional flow of water delivered by the reservoir, causing a reduction in oil productivity. Hence, in most cases the oil production was reduced after DPR gel treatment.

INTRODUCTION

DPR gel treatment represents an interesting water shut-off technique, as the main attraction is that placement could become simple and cost effective - just by bull-head injection. An ideal DPR gel system is envisaged to reduce the water cut and improve, or at least maintain, the oil production from the treated well.

The Veslefrikk field, which has been on production since 1989 with water injection as the main drive mechanism, is located in the Northern North Sea. The production wells are experiencing increased water production, and it is important to have available effective water shut-off technologies. In this respect the potential for DPR gel was evaluated, with main focus on bull-head treatment.

A full field Veslefrikk Eclipse model, including liftcurves, was used in the evaluation study. The model has 20 numerical layers representing the Intra Dunlin Sand (IDS) and the Brent Group. The layer permeabilities are ranging from 5 to

800 mD, with a varying degree of vertical communication.

As production constraints and communication between layers is expected to affect the potential for DPR gel treatment, wells selected for the study covers different conditions. Table 1 shows the tubing head pressure (THP), bottom hole pressure (BHP) and the actual water cut for the wells evaluated. As indicated, the production wells are constrained either by minimum THP (25 bar) or minimum BHP (200 bar).

SIMULATIONS

Base cases

The first six wells shown in Table 1; P-1 to P-6, are vertical wells producing from the Veslefrikk field at present. In addition, one horizontal well was simulated in the same area as P-2. In all simulations the field pressure was maintained with water injection throughout the gel treatment period.

Local grid refinement was used in the well grid blocks, in the x- and y-direction. The z-direction (depth) was not refined. The gel treatment radius was 9 metres, covering all perforated layers.

The DPR effect observed for several polymers and gels are not fully understood, and different mechanisms have been suggested.¹⁻⁴ In this study a true DPR gel system is assumed to be present. The effect of DPR gel was modelled as reduction in the relative permeability curves for water in the treated zone, using a reduction factor (RF_w), which describes the strength of the gel. The oil relative permeability curves were not changed.

Table 1 shows that the production from P-1 and P-5 are constrained by minimum BHP. The other

wells are constrained by THP. The table also shows that P-1 and the horizontal well H-1 have not experienced water break-through.

The well P-2 will be given special attention as it appeared early in the study to be one of the better candidates. The well is perforated in 9 layers. Table 2 shows the fluid rate and the watercut for each layer, at start of the simulated gel treatment. The high permeable layer number 2 has no water production and contributes with 50 % of the total fluid rate in the well. Layer number 3 contributes with 37 %, and has a watercut of 9 %. There is no vertical barrier between layer 2 and 3 in the near-well area.

The other vertical wells were perforated in layers with a varying degree of vertical communication and fractional flows. The 600 metres long horizontal well, H-1, was placed in layer number 2 in the P-2 area since this layer had the highest oil production potential. The vertical well P-2 was shut in when simulating the horizontal well.

All the vertical wells were treated with DPR gels having reduction factors of 10, 100 and 1000, respectively. The horizontal well, H-1, was treated with DPR gels with reduction factors of 10 and 100, respectively. The range of values have been reported from core floodings and special simulation studies on DPR gel.^{5,6}

In cases without gel treatment, the wells are producing until a watercut of approximately 85 %. The gel treatments were simulated to the same point in time, and the cumulative oil and water production compared. Due to interpretation of the results, only one well was treated in each simulation.

Sensitivities

Selective placement

Instead of treating the entire perforation interval, as in the base cases, gel was now placed only in water producing layers. This can be compared with traditional water shut-off techniques as mechanical straddling or cementing. The drawback with straddling is the introduction of obstructions inside the production tubing. A drawback with both techniques is that water may pass the treated zone and enter the remaining perforation interval. This is in particular the case when the communication between the treated and untreated zones is good, or if sealing shales for some reason are broken in the near well zone. In

well P-2 all layers except layer 2 were treated with a DPR gel that had a reduction factor of 100. As the water cut from this layer was zero, an accelerated oil production was expected.

Treatment area

The effect of extended gel treatment area was simulated for wells P-2 and P-4. The radius of the extended area was 35 metres, using a gel with reduction factor of 100.

Furthermore, a permeability height (Kh) dependent treatment area was simulated, which gives a penetration depth in each layer analogue to what can be expected from bullheading.

Relative permeability curves

After the field simulations for this paper were finished, history matching of a coreflood experiment showed that the observed build up of water saturation in the gel plug preferably should be modelled as an increase in the connate (critical) water saturation.⁴ This new procedure was tested in a gel treatment in P-2 with reduction factor of 100.

RESULTS AND DISCUSSION

Base cases

Figure 1 shows the cumulative oil and water production from all wells, without gel treatment. The total production period is given with number of years in brackets.

The cumulative oil and water production for well P-2 after gel treatment with different RF_w , is shown in Figure 2. Included is also the case without gel. The weakest gel, with a reduction factor of 10, reduced the water production with 28% and the oil production with 4%. The strongest gel, with reduction factor of 1000, lowered the water production with almost 100%. However, this gel reduced the oil production with 61% compared with the case without gel.

The time development in THP and BHP for P-2 with and without DPR gel, is shown in Figure 3. The RF_w in this case was 100. Since the well was constrained by THP, the reduced water production allowed for a reduced BHP and increased well oil production rate (WOPR) for a short period of time. After water-breakthrough in layer 2 the well production rate dropped below the pre-treatment rate, see Figure 4. Although the reduced watercut allowed for increased

drawdown, this was not sufficient, except for the first three months, to fully compensate for the reduced productivity.

This result indicates that even in laminated reservoirs, with some low-watercut layers, a DPR gel treatment may be detrimental.

Normally a reduction in water production, due to DPR gel treatment in the entire perforation interval, does not necessarily imply a reduced water saturation in the interwell area.⁴ Though the water production rate is reduced, the water oil ratio (WOR) in each layer will be relatively unchanged in the treated area. Since the relative permeability to water is reduced in the gel plug, the water saturation in the treated zone must increase to accommodate the WOR prescribed by the reservoir. Hence, the oil mobility is reduced even if the oil relative permeability is not modified, which explains the observations in P-2.

The increased water saturation in the gel treated area is illustrated in Figure 5 for well P-3, with an $RF_w = 10$. The figure shows the water saturation in the gel treated well block and in four neighbouring grid blocks radially distributed around the gel plug. The water saturation increased from 55 % outside the gel plug to 65 % inside, resulting in a significant reduction in oil mobility.

The results from all the DPR gel base case simulations are plotted in Figure 6. The figure shows the change in oil production as a function of reduction in water production. A line from point (0,0) to point (100,100) represents the "no selectivity" line, i.e. the relative change in oil production and water production is identical. Increasing gel strength increased the reduction in both oil and water production for all base cases, as illustrated for P-2 in Figure 2.

The three wells P-3, P-4 and P-6 are all close to the "no selectivity" line. This is due to water break-through in all perforated layers before gel treatment.

Figure 6 also shows a successful gel treatment in P-1. This well penetrates 3 layers, of which 1 produced at 0 % watercut for a long period of time after gel treatment. However, as indicated in Figure 1 the absolute production volumes for this well are small.

The horizontal well H-1 is represented in Figure 6 with two points, for the RF_w values 10 and 100. Gel treatment in this well redistributed the water producing intervals and gave earlier water break-through in some intervals compared with the non-treatment case. This is the same effect observed in P-2, causing accelerated water break-through in some layers.

Sensitivities

Selective placement

When P-2 was treated with DPR gel only in the watered out layers, an accelerated oil production was observed, see Figure 7. With this placement technique the productivity of the non treated layers was not damaged. Hence the oil fractional flow in the well increased, causing an improved oil production rate for the following 2.5 years. Due to limitations in BHP and THP, the oil production rate thereafter dropped as layer 2 watered out. The watercut reached the same level as for the case without gel 2.5 years after gel treatment, see Figure 8.

Treatment area

The simulation with extended gel treatment area delayed the sharp decrease in oil production, observed in Figure 4 for the base case gel, with 3 months, while the cumulative water and oil production were not affected. Likewise, the Kh based placement did not affect the production compared with the base case.

Relative permeability curves

Using the new DPR gel modelling approach,⁴ the cumulative oil and water production were reduced with 36 % and 87 % respectively. Base case gel treatment showed 28 % and 81 % reduction in cumulative oil and water production. The overall production profile followed the same trend as the base case gel.

General

As discussed above, none of the DPR treatments increased the oil production. The main reason is that the reduction in productivity could not be compensated by increased drawdown, due to operating constraints. This problem is most severe when water is produced in the entire perforation interval. In the extreme case, with homogenous watercut and productivity distribution along the wellbore, DPR gel treatment will not change the overall watercut even with full compensation for productivity reduction.

It is also demonstrated that in homogenous reservoirs or in reservoirs with good communication in the direction of the well path, bullhead injection of DPR gel may be detrimental even for cases where only parts of the perforation interval experience pre-treatment water production. The reason is that the post-treatment reduced permeability in the water producing zones promote a redistribution of water towards non-water producing intervals, which then experience earlier water breakthrough. The results may therefore be an overall reduced oil productivity.

Hence, for bull-head treatment it seems that the promising well candidate are situated in layered reservoirs with limited vertical communications and where water production is limited to a restricted number of these layers.

CONCLUSIONS

- The potential for bull-head DPR gel treatment is in general low for the wells investigated.
- DPR gel causes a reduction in oil mobility in the presence of water, even though relative permeability to oil is not modified.
- Reduced oil productivity could, in general, not be compensated by increased drawdown.
- DPR gel do have a potential for wells in layered reservoirs with no vertical communication, where some layers are producing with zero or low watercut.

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TABLES

Table 1. Wells selected for gel treatment.

Well	Tubing head pressure [bar]	Bottom hole pressure [bar]	Watercut [%]
P-1	48	200	0
P-2	25	254	11
P-3	25	235	22
P-4	25	215	14
P-5	28	200	39
P-6	25	260	76
H-1	25	270	0

Table 2. Fluid rate, watercut and MULTZ* in P-2 at start of simulated gel treatment.

Layer #	Fluid rate [%]	Watercut [%]	MULTZ*
1	0.5	11	0
2	50	0	1
3	37	9	1
4	4	42	0
5	0.5	32	0
6	1	0	1
7	5	90	1
8	1	64	1
9	1	77	1

*MULTZ : Multiplication factor for vertical transmissibility

FIGURES

Figure 1. Total oil and water production during planned gel period, years on production in brackets.

Figure 4. Oil production rate (WOPR) and watercut (WWCT) in P-2 with ($\text{RF}_w = 100$) and without ($\text{RF}_w = 1$) gel treatment.

Figure 2. Total oil and water production from P-2 during treatment period, for different reduction factors (RF_w).

Figure 5. Water saturation (S_w) in gel treated and untreated area, well P-3.

Figure 3. Bottom hole pressure (WBHP) and tubing head pressure (WTHP) in well P-2 with ($\text{RF}_w = 100$) and without ($\text{RF}_w = 1$) gel treatment.

Figure 6. Change in oil production as a function of decrease in water production, for different gel strength.

Figure 7. Oil production in P-2, base case without treatment, gel treatment in all layers and selective placement.

Figure 8. Watercut in P-2, base case without treatment, gel treatment in all layers and selective placement.