012 APPLICATION OF A NOVEL GAS SINGLE-WELL TRACER TEST TO DETERMINE REMAINING OIL IN GAS FLOODED RESERVOIRS

ARNE SKAUGE¹, TOVE LIND¹ and HARRY A. DEANS²

¹ Norsk Hydro ASA, 5020 Bergen, Norway

² Wyoming University

Abstract

An approach have been tested to obtain a reservoir estimate of residual oil saturation after gas injection. The methodology is similar to the well-known Single-Well Tracer Test that has been used to measure waterflood residual oil saturation in-situ in more than 200 field trials since 1968. The gas tracer test was performed at the Oseberg Field, well 30/9-B-03. The actual formation had been gas flooded and was assumed to be at residual oil saturation.

Laboratory studies were carried out to quantify chemical reaction kinetics and partition coefficients between oil, water, and gas phases for both injected and produced tracers. The field test design, tracer concentration, reaction, and soak-in time were as expected from laboratory data. The concept of single well gas tracer test has been found to be applicable for the Oseberg field conditions. The tracers; SF₆, DMC and CO₂ were backproduced at about the same time in the main test, indicating very low liquid saturation in the contacted reservoir zone.

Introduction

The Single-Well Chemical Tracer (SWCT) Test¹⁻³ has been used to measure residual oil saturation in-situ in more than 200 depleted formations since 1968. In all of these applications, water was the mobile phase in the target formation. The SWCT test has been applied also at the Oseberg field (1992) in the single well surfactant tracer test^{4,5} of well 30/9-B-12A. The single-well gas tracer test is a new application of single well tests.

The single well tracer test applies a partitioning tracer that reacts in the reservoir to form secondary tracers with different partitioning properties. The main tracer is pushed to a radial distance from the well. Thereafter a soak period secures the production of the secondary tracers, usually by a hydrolysis reaction in the water phase. When backproduced, the tracers will be delayed according to their individual partitioning to the resident phases of the reservoir. The single well gas tracer test gives an average saturation over a large distance from the wellbore compared to logging tools. The single well test makes the contribution from the very near region (< 50 cm) around the well negligible. The tracer test therefore reflects a more representative region of the reservoir.

Three different partitioning tracers are necessary to determine the unknown saturation of two phases, both connate water and residual oil. The hydrolysis secures that the injected tracer and the reaction product tracers are located in the same position after a soak-in period. The tracers should thereby arrive at the well carried in the gas phase, in the order of their partitioning to connate water and residual oil. If no oil or water is present all the tracers should arrive at the same time and the production profile of the tracers should overlap.

The procedure developed is shown schematically in Figure 1. The primary tracer is Dimethyl Carbonate (DMC), which has a sufficiently high vapour pressure to be injected in gas (the mobile phase), if reservoir temperature is high enough. The Oseberg reservoir temperature of 100°C is ideal for using DMC as a gas tracer. DMC distributes in the pore space among all three phases present; mobile gas, connate water, and residual oil. The local velocity of DMC in the pores is thus dependent on the volume fractions of water and oil present, and on the thermodynamic equilibrium distribution coefficients of DMC at reservoir conditions. The velocities of CO₂ and methanol, the two products of the hydrolysis reaction, are functions of oil and water saturations according to their distribution coefficients.

The distribution (partitioning) coefficients of the three tracers between oil, water and gas have to be determined from laboratory studies. If we know how the tracers distribute between the phases, then we can calculate the saturation of

the resident phases, Swi and Sor, from analysis of the arrival time of the tracers. Again three tracers are needed as two phases are unknown.

A test program of several single-well tests was defined with the objectives of optimising test design (injected tracer concentration, slug size, push volume, and soak in time), and thereafter determine immobile water and oil saturation within a given radius from the wellbore. The main objective of the gas tracer tests was to try a new approach to determine the oil saturation behind the gas displacement front. B-03 was selected because the well has been an observation well in the ORE formation without any substantial production, and the TDT-P log data had shown that the gas contact was below the bottom perforations.

Methods

Dimethylcarbonate was injected into the gas stream, during soak-in the DMC will hydrolyse to form methanol and carbondioxide. The difference in return-time for the three tracers determines both the water and oil saturations. Laboratory studies were carried out to quantify chemical reaction kinetics and partition coefficients of injected and produced tracers.

Materials. Properties of chemical tracers. The main tracer Dimethyl Carbonate has purchased from SNPE Chimie, Toulouse, France in a quantum of 400 kg. The C-14 tagged DMC was synthesized at DuPont Chemical Company and supplied by Laborel, Norge. Argon was supplied by Hydrogas in 50 litre pressure bottles, and was compressed to injection pressure by a booster pump. SF₆ was also delivered by Hydrogas in pressure bottles. The measurements of the tracers were done by the same gas chromatography analysis both in laboratory studies and field tests. The only exceptions were the C-14 tagged CO₂ and DMC that were measured by scintillation counting.

Field implementation. The injected tracer had to be dispersed into the well stream. As 30/9-B-03 was an observation well, the near wellbore region had been little influenced by local high rate flow. Though, production tests have been performed before the tracer tests. The gas used to push the tracers must be in equilibrium with the reservoir fluids. We used the standard injection gas which is a mixture of processed Oseberg and Troll gas. A 60/40 ratio of Oseberg and Troll gas would be in equilibrium with the reservoir fluid and should secure that compositional exchanges gave no change in the phase saturations.

The gas oil contact in B-03 had been monitored by TDT-P logging. The contact was observed to be close to the bottom of the perforation interval 28. September 1990. The single-well gas tracer tests were carried out during July to October 1993.

The well is a low-deviation (30 degrees) observation well drilled to monitor the gas front on the Alpha structure. Later on, the well is planned to be a gas injector. Formation temperature 103 deg.C, formation pressure 274.5 bar at depth 2782m RKB. The average petrophysical results for the Upper Oseberg (2782.5-2817 m MDRKB) were, porosity 26.2%, and Sw 6.8%.

The gas injection rate was kept low in the range of 10,000 Sm³/hour for all injection sequences. This will convert to a reservoir injection rate of about 50 Rm³/hour. The low rate was used to avoid that oil was mobilised during gas injection. The capillary number should be sufficient low to assure no mobilisation of oil. However, injection of dry gas may cause some mass exchange between oil and gas, leading to a reduction of Sor. This effect is assumed to be minor based on information from the compositional analysis of the injected and produced gas. The production rate was in the order of 15,000 Sm³/hour.

Injection equipment and procedures

The injected gas for the single well gas tracer tests was routed from an injection manifold to the kill-line. The tracers were injected through a coupling at the top (the hub) of the kill-line. DMC was supplied by an air-driven Lygre-pump, while the gas components Argon and SF₆ were delivered by a booster pump. The gas component flow rate was controlled by a mass flow meter and by the change of pressure on the pressure bottles. DMC was monitored by a flow metering system on the Lygre pump. The radioactive tagged DMC was injected into the line connecting the Lygre pump to the kill-line. The tracer injections for all tests are reported in Table 3. The lower DMC concentration in two tests (3 and 4) was due to valve problems. The backproduced methanol from tests 3 and 4 gave too low concentrations to be able to detect the tracer peak position.

Gas was sampled through a sampling probe placed on the kill-line of the well. The backproduced tracers were analysed directly on the platform. Gas samples were obtained by flashing the produced gas to atmospheric condition in a single step. The single stage flash was performed at the well-head, and gas was sampled in sealed plastic bags. During the sampling of gas, problems with gas hydrates were observed occasionally. Steam was used to melt the hydrates and to prevent new hydrates from forming. Gas was sampled every ten minute at start of backproduction, the sampling frequency was later reduced to one sample per half hour towards the end of the production. The single-flash sampling showed a GOR of about 15,000 (Sm³/Sm³). The wet gas produced by single flash to ambient conditions was expected to give some liquid in the range of the GOR observed. The GOR observed was as expected. Both gas and condensate were collected at the site. The gas was sampled in a period of about 2 minutes at a constant flow, while the condensate was sampled continuously and collected every 10 minutes in glass vials. Gas was sampled in evacuated sealed plastic bags of 1 litre and 3 litre. The larger samples were used for analysis of radioactive tagged CO₂.

The production profiles of tracers were analyzed and compared. Estimates of water and oil saturations were obtained by history matching using a compositional tracer simulation model modified from a water tracer single well test simulator.

Results and discussion

Laboratory measurements. Dimethyl Carbonate hydrolysis rate was measured by dissolving DMC in brine at reservoir temperature, and measuring the concentration of DMC and reaction products as a function of time the average reaction constant was calculated to 1,0 days⁻¹. The partition coefficients were measured by equilibrating in pVT-cells and sampling at reservoir condition. Measurements from flow injection analysis¹ were also obtained through Gougolans MS-thesis supervised by Prof. Harry Deans at the University of Wyoming. The corrected K-values have been used in the history match simulations of the field single well gas tracer tests, and are shown in Table 1. The difference of partitioning coefficients between the two methods were minor and only involved the K(o/g) for CO₂ and the partitioning of DMC. The material balance tracers Argon and SF₆ have low partitioning to the water and oil phases, and are assumed to follow the gas phase.

Field tests. The injected gas should preferable have the same density as the field gas phase to avoid any segregation in the reservoir, and should also be in equilibrium with the oil to eliminate any mass transfer. The CO₂ produced by the hydrolysis should be tagged to distinguish from the CO₂ present in the reservoir. The CO₂ in the reservoir gas and reaction product from the tracer hydrolysis were differentiated by carbon-14 tagging the DMC so that the produced CO₂ also contained the tagged carbon atom. The hydrolysis reaction only takes place in the water phase, and the test design assumes local equilibrium between oil-water-gas for the partitioning coefficients to be representative. Local equilibrium was also assumed during backproduction.

As detailed knowledge of the radial saturation distribution is not available from the single-well tests, the immobile phase-saturations were assumed constant in all history match simulations. This may inflict an error in the simulation, however, the volumetric average water saturation in the contacted zone is determining the tracer response, and therefore this possible error is of less importance.

A total of five tracer injections have been conducted in order to determine residual oil saturation behind the gas displacement front in the ORE formation of B-03, Table 2. Because this type of single well test is novel, the first test aimed at evaluation of the process design. The tracer concentration, tracer slug size, push volume and soak in time initially selected prior to the field test, proved to be a good first choice and were kept at similar level in the following tracer injections. The design optimisation test revealed that the chemical analyses of the tracers were less accurate than expected, and absolute concentrations and material balance of injected/produced tracer were not obtained. Figure 2 shows the backproduced DMC and methanol from Test 1. The production profile of methanol shows a sharp peak, while the DMC has a more dispersed production versus time.

Argon was used as a material balance tracer. GC analysis showed that the gas samples had oxygen present. Unfortunately air contains enough Argon to interfere with the test results. The Argon concentration was calculated by correcting for the oxygen level in the sample. In Test 5 an additional material balance tracer SF₆ was used. This tracer gave a much better response during backproduction. Figure 3 and 4 show results for the material balance tracers.

The injection mixture of Troll and Oseberg gas will contain 9000 ppm CO₂, compared to 11,500 ppm in the resident Oseberg gas. This illustrates the necessity of tagging the injected CO₂ for measurement of residual oil saturation.

Tests 2 and 3 sought primarily at determination of the water saturation, analysed by the time delay between backproduced DMC and methanol. The calculated water saturations were found to be very low, $S_w < 10\%$. The design optimisation test, T1, gave a water saturation of $< 5\%$. Tracer production profiles are included in Figure 2. The log data from B-03 had earlier reported a connate water saturation of 6,8 % for the Upper Oseberg formation. Single-well tracer tests at different well radius indicated that the water saturation may increase with radial distance.

The injected tracer, DMC, was delayed in all tests compared to ideal time for backproduction. There are several reasons for such an effect, drift of the injected tracer, liquid accumulation in the well or near the wellbore zone, segregation of the injected gas, or inhomogen inflow/outflow performance. Tracer drift must be due to pressure gradients from production in the area around the, B-03, well. The drift caused by pressure gradient is expected to be in the range of 0.5 m/day, and seems insufficient to create the delay in DMC. Also segregation is unlikely as the difference in gas density between injected gas and field gas is very small. In conclusion liquid saturation (condensate drop out or injected liquid) or inhomogen inflow/outflow performance seems the most likely reason for the delayed DMC and material balance tracer SF6.

The main tests, 4 and 5, made use of radioactive tagged DMC to monitor the oil saturation. The radioactive part of the molecule is the carbonyl group, which during hydrolysis made tagged CO₂ as a secondary tracer. The difference in the backproduced CO₂ and DMC determines the residual oil saturation. The tests, 4 and 5, show very little difference in the peak response of the radioactive tracer, CO₂, and DMC, which indicate that the residual oil saturation was very low, less than 10%. Tracer response is given in Table 3, and Figure 5 shows the production data from test 5. Comparing different methods for determination of residual oil showed good agreement between the single well test and microscopic displacement efficiency from laboratory long core gas injection experiments⁶.

Conclusions

The concept of single well gas tracer test has been found to be applicable for the Oseberg field conditions. The test design tracer concentration, reaction, and soak-in time were as expected from laboratory data.

The chemical analysis was non-quantitative, and only relative concentrations could be detected. This reduced the interpretation and accuracy of the tests as material balance could not be controlled.

The water saturation is low ($S_w < 10\%$) when calculated from comparing backproduction of DMC and the hydrolysis reaction products, methanol. This result agrees with log data. Water saturation seems to increase with radial distance.

The backproduction of DMC was delayed in all tests, possible due to layering effects. The tracers; SF₆, DMC and CO₂ were backproduced at about the same time in the main test, indicating very low liquid saturation in the contacted reservoir zone. The residual oil saturation was estimated to be less than 10%.

The results of analysis of the single-well gas tracer tests agree with microscopic displacement efficiency measured in laboratory long core studies.

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Table 1. Distribution coefficients (K-values) for the tracers in reservoir fluids at 280 bar, 100C

	DMC	MeOH	CO ₂
Partitioning coefficient (oil/gas):	7,8	0,4	1,5
Partitioning coefficient (water/gas):	7,4	26	1
Partitioning coefficient (oil/water):	1	0,02	1

Table 2. Field test overview

Test 1	Test design optimization
Test 2	Water saturation determination
Test 3	Extended water saturation measurement test
Test 4	Main Test, Residual oil determination
Test 5	Main Test 2, Residual oil determination, increased tracer concentration

Table 3. Tracer injection and production data

Tracer injection	Test 1	Test 2	Test 3	Test 4	Test 5
Partitioning tracer, DMC:	2,000 ppm	2,000 ppm	1250 ppm	600 ppm	2,000 ppm
Material balance tracer, Argon:	100 ppm	100 ppm	100 ppm	100 ppm	100 ppm*
Tracer slug:	42.3 Rm3	59.3 Rm3	198 Rm3	193 Rm3	188 Rm3
Push volume (incl. wellbore volume):	165.6 Rm3	355.7 Rm3	642 Rm3	725 Rm3	514 Rm3
Injection rate	49.5 Rm3/hr	59.3 Rm3/hr	49.9 Rm3/hr	48.3 Rm3/hr	44.6 Rm3/hr
Soak in	24 hours	16.75 hours.	24.75 hours.	17.9 hours.	23.4 hours.
Estimated peaks of backproduced tracers:					
Dimethyl Carbonate(gas):	175 Rm3	500 Rm3	900 Rm3	822 Rm3	1200 Rm3
Dimethyl Carbonate(cond):	250 Rm3	500 Rm3	not detect	not detect	1300 Rm3
Methanol:	72 Rm3	115 Rm3	300 Rm3	850 Rm3	not detect
Carbondioxide:	63 Rm3	85 Rm3	600 Rm3	1150 Rm3	1350 Rm3
SF ₆					1250 Rm3

* plus 500 ppm SF₆

Figure 1. Illustration of the Single-Well Gas Tracer Test

Figure 2. Backproduced DMC and MeOH from Test 1

Figure 3. Produced Argon from Test 2

Figure 4. Production of material balancetracers from Test 5

Figure 5. Production of tracers from Test 5