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COMPARING CORE ANALYSIS DATA TO FIELD OBSERVATIONS FOR GRAVITY DRAINAGE GAS INJECTION

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Abstract

A summary of core analysis data and uses of core analysis in the decision of selecting gravity drainage as the drive mechanism for the Oseberg field is presented. The oil field is located in the North Sea area, and is one of the larger oil reservoirs. Field measurements of residual oil saturation were estimated from well logs, sponge coring, and single-well transient tests. The results are compared to the measurement from laboratory water floods and gas injection.

Residual oil saturation estimated from laboratory measurements agree with estimates obtained from field test measurements. Long core gas injection, centrifuge oil drainage experiments, and single-well gas tracer tests all confirm an estimate of residual oil saturation of less than a saturation fraction of 0.1 for the Oseberg field. Gas front monitoring has confirmed stable gas front evolution at high oil production rates from the main reservoirs.

Introduction

Gravity drainage has been recognized for a long while as a very efficient oil recovery process[1-6]. High oil recoveries have been proved both for secondary and tertiary processes[7]. The East-Texas Hawkins reservoir[2] reported estimated displacement efficiency of 87 per cent by gravity drainage. Since then, many reservoirs have confirmed the efficiency of gravity drainage[6,7]. The advantage of exploiting gravity to improve oil recovery is specially attractive for high permeability, light oil reservoir, where the response time is reasonable short. A characteristic of most gravity drainage processes is the existence of a gas cap. The reservoir also should have a reasonable dip, and preferably high permeability, but it has also been applied in fractured low permeable reservoirs. The reservoir engineering guideline for gravity drainage[8] has been to maintain pressure by gas injection at the crest of the structure.

The importance of gravity drainage has led to many laboratory investigations of this oil recovery process[1,7-16]. Gravity dominated laboratory displacements can be classified as; <u>Controlled gravity drainage</u> or gravity stable, low rate gas injection, or <u>Free gravity drainage</u> - free segregation of fluids in a gravity field. Usually gravity drainage has been performed in vertical oriented long core experiments.

A brief literature review shows that Katz[1] reported recovery efficiency in a free gravity drainage production from the Wilcox reservoir sand in Oklahoma. A residual oil saturation (ROS) was measured as low as 6-8% at the top of the plug at equilibrium. Terwilliger et al[8] presented production and fluid saturation distribution as functions of both time and distance, and also measured fluid saturation continuously during the experiments by considering the changes in conductivity as a function of time and length. The experiments were performed at constant rate gas injection. Terwilliger et al[8] showed that the shock front was smeared out into a capillary transition zone whose shape remains stationary as the front progresses.

Dumore and Schols[9] reported that the presence of immobile water in Bentheim sandstones during gravity drainage resulted in very low residual oil saturations. They concluded that the result can be achieved both for high and low gas/oil interfacial tension. Kantzas et al[11] studied production by gravity drainage in both Berea sandstone and in unconsolidated sand columns of various lengths. The experiments which included free and controlled gravity drainage revealed higher recoveries when the tests were started at residual water saturation than when started at residual oil saturation. Skauge et al.[12] found, for sandstone cores under water wet conditions, that oil recovery increased with connate water present compared to no water present. The influence of water-oil capillary pressure was found to change (reduce) the drainage rate, and also reduced oil relative permeability.

Pavone et al[13] studied free gravity drainage at low interfacial tension in fractured reservoirs. One of their conclusions is that the presence of immobile water reduces the oil relative permeability and thereby reduces oil production. In this respect free gravity drainage seems to deviate from gravity stable gas injection.

In modeling of gravity drainage experiments usually a asymptotic residual oil saturation equal to zero is applied[14], even though average remaining oil saturation may be a fraction of about 0.1 – 0.2. The topic of residual oil saturation will be discussed later.

This paper presents a case study where SCAL data helped decide field drive mechanism. The laboratory generated gas – oil relative permeability has been successfully applied in the reservoir simulations. The estimated remaining oil saturation from laboratory studies and also the simulated gas frontal movement have been compared to field observations.

Oseberg Field

Updip gas injection has been the main drive mechanism in the oil production from the Oseberg Field since the start of production in December 1988. The oil field is located in the North Sea area, and is one of the larger oil reservoirs. The paper summarizes data on relative permeability and residual oil saturation after gas injection, and show how field measurements and interpretations have been applied for monitoring of the gas displacement process.

Oseberg is a high permeability sandstone reservoir belonging to the Middle Jurassic Brent Group. The main oil bearing formation is the ORE-group (Oseberg-Rannock-Etive), but considerable reserves are also located in the Tarbert formation and recently oil recovery from the Ness channel sands have been upgraded[15]. The field reservoir geology[5,15] and production monitoring[15,17,18] have been described in earlier presentations. Reservoir dip angle is about 8 degrees, and average permeability of about 3 Darcy. The oil field is developed primarily by full scale gas injection supplemented by water injection in some reservoir units. Re-cycling of produced gas, and gas imported from the Troll field is used for pressure support. Production monitoring and reservoir monitoring[15,17,18] have confirmed gravity stable gas front evolution. The expected ultimate recovery is about 60 per cent of the original oil in place. Oil production was started late 1988, and currently more than 65 per cent of the estimated reserves have been produced.

Reservoir monitoring by TDT-P logs. The gas - oil relative permeabilities have been compared to field observation of gas frontal movement by repeated TDT (Thermal Decay Time) logging. The average gas front movement has been 5 cm/day TVD, as shown in Figure 1. The maximum gravity stable displacement rate[19] is in the order of 50 cm/d. The TDT results are used for production planning. The production rates have been adjusted to assure an even and stable gas front in Oseberg. TDT data from some wells indicates that the gas front in Etive and Lower Ness is behind the gas front in the Oseberg formation. The low permeability Rannoch serve as a flow barrier between Etive and Oseberg. More details of the reservoir management are presented in reference 17.

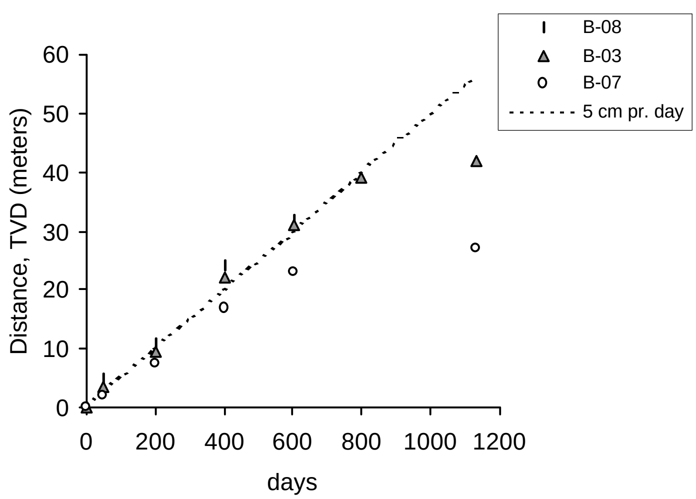


Figure 1. Gas front from repeated TDT-P logs in observation wells.

Experimental

After the discovery of the Oseberg Field a large number of core flood experiments have been performed to evaluate the residual oil saturation both after water- and gas-injection. The experiments indicated that even an equilibrium gas injection in Oseberg was more favorable than a waterflood. Any compositional exchanges between a dry injection gas and the reservoir oil would increase the oil recovery further.

Extensive effort was made to investigate if laboratory cleaned cores can give reliable core analysis data for this reservoir. Restored cores was compared to fresh cores. Wettability proved to be quite robust and it was difficult to clean cores to water wet condition before restoration. Water flood relative permeability studies showed fairly good agreement between fresh and restored cores. Different experimental techniques (unsteady state, steady state, and centrifuge methods) have been used to estimate relative permeability for water flood and gas injection. In this paper the focus will mainly be on gravity stable gas injection.

The permeability of the core material varies from 100 mD to several Darcy's. The average permeability is in the Darcy range (1-3 Darcy) though some formations may show variation, the permeability is in general rather homogeneous compared to most reservoirs. The core material is quite well consolidated for such high permeabilities.

Relative permeability

The differential pressure even for a long core may be very low for gravity stable gas injection, and only detection of effluent production may result in low accuracy of the estimated relative permeabilities. Knowledge of the fluid saturation greatly improves the calculation of relative permeability and interpretation of gravity drainage experiments.[20] A match of the effluent production from gravity drainage by a laboratory simulator may not be unique. Properties like capillary forces, wetting, variability of porosity and permeability will influence the distribution of the phases during the gravity drainage. The effect of water-oil interactions on oil gravity drainage by gas injection is reducing the oil drainage rate, and it may also effect the oil relative permeability and oil recovery. Oil relative permeability is found to increase with a water phase present in the core during the drainage process[12].

Alternatives to long core gravity drainage have been to measure the oil relative permeability by centrifuge using the method developed by Hagoort[14] or else use gas flooding (gas injection at a constant differential pressure. Gas relative permeability is usually calculated from constant differential pressure experiment (gas flooding). Long core gravity drainage only generate endpoint k_{rg} with reasonable accuracy, but better estimate of the k_{rg}-curve may be obtained if in-situ saturation data is available. Endpoint gas permeability can also be found by gas flooding the core after k_{ro} is determined by drainage in the centrifuge. A dimensionless number, the Dowbrowski-Brownell number[21] is used as a reference state that characterizes microscopic flow and the balance between gravity and capillarity:

$$N_{DB} = (D rgk)/(g) \qquad (1)$$

N_{DB} , also known as the microscopic Bond number, is usually in the order of 10^{-5} for gravity-drainage processes[14], and should not exceed 10^{-3} in centrifuge experiments[14].

Oil relative permeability is a key factor in the gravity-drainage process. The oil relative permeability have frequently been estimated from gravity drainage experiments[14,19,23-28]. The data is often represented by a Corey[22] exponent and using a asymptotic residual oil saturation equal to zero[14]. Corey et al[23] proposed an oil exponent of 4, for three phase flow.

A Corey representation is often used for ease of comparison, but when using information about frontal movement during gravity drainage a constant exponent does not describe the process,[19,25,27]. The oil flow will be dominated by bulk flow at high oil saturation, but the microscopic flow will change to oil layer flow or film flow at lower oil saturation. DiCarlo et al[27] show that the Corey exponent change from a value of 4 at high oil saturation to about 2 at low oil saturation.

Though, Corey description is incorrect for gravity drainage, this procedure will be used for convenience to compare different relative permeability data in this paper. In the literature, oil relative permeability for gravity drainage has been repeatedly measured as a Corey exponent of about 4[14,23,27,29]. Fenwick and Blunt[30] also have estimated an oil exponent of 4 from three-phase network models. estimated n_o=4 .

In a paper by Hagoort[14] several sandstone cores were measured by the centrifuge technique. The oil exponent was between 4 and 8 in all cases, under the assumption of $S_{org} = 0$. High oil exponent has also been reported for free gravity drainage[24], n_o=6.5. It is expected that the bulk flow during high oil saturation gravity drainage is determined by the permeability of the porous media.

Capillary gradient is large near the bottom of the core, while at the top, capillary effect is small compared to the gravity gradient. The relative permeability calculations should include consideration of capillary end-effects.

Oseberg Gas – oil relative permeabilities.

A large number of gas – oil relative permeability studies have been performed on core material from the Oseberg reservoir. This presentation cannot cover all the experiments, but will highlight the main results. First, long core displacements will be presented. A long core (163 cm composite core from the Tarbert formation) was used for a gravity stable gas injection with equilibrium hydrocarbon gas at reservoir conditions. Permeability was 1300 mD, and S_{wi} was 0.251. The frontal advance rate was about 5 cm/day. The measured remaining oil saturation was 0.08. Extraction of the core elements after the experiment confirmed the production data. The calculated oil relative permeability (core A)is presented in Figure 2. The slope of the k_{rog} curve change to lower Corey exponent at low oil saturation similar to reported data from DiCarlo et al[27]. They suggested Corey exponent changed from 4 to 2 at saturation below S_{orw}.

An other example of long core studies is the core B in Figure 2. This core was from the Oseberg formation and had a permeability of 2 Darcy. Again equilibrium gas was injected from the top of the 39 cm long core. The flow rate was 2 cc/hr, and a remaining oil saturation of 0.3 was found. History matching the experiment including capillary pressure gave a Corey exponent of 4 with a S_{org} of 0.1. The experiments C and D are repeated gravity drainage at slightly different flow rates. The calculated oil relative permeabilities are in fairly good agreement with data from exp. A and B.

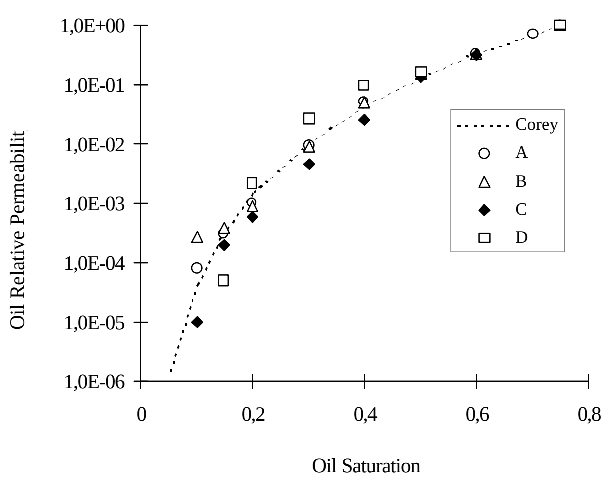


Figure 2. Oil relative permeability from long core, vertical gas injection experiments

Data from gravity stable long core experiments show consistently low remaining oil saturation all less than a fraction of 0.15. The gas displacements can be matched by using a Corey exponent of 5 and a asymptotic residual oil saturation of zero, or by a Corey exponent of 4 and a S_{org}=0.1. The latter data set have been used in reservoir simulations of the gas injection process. The difference between the two oil relative permeability representations is insignificant at $k_{ro} > 10^{-6}$, and for $k_{ro} < 10^{-6}$, the oil relative permeability is set equal to zero in the simulator, anyway. The gas - oil relative permeability data measured in the period of the field development plan (1983-1984) has survived all revisions during the years and is still today used in reservoir simulation studies.

Oil relative permeability have been calculated from centrifuge measurements (Hagoorts method[14]) of core plugs from all formations of the Oseberg field. Two examples of centrifuge estimates are compared to gas flood calculated relative permeabilities, in Figure 3 and 4. The Figure 3 shows a good agreement between gasflood and centrifuge data. The core plug had a permeability of 400 mD, and was spun at 2500 rpm equivalent to a Bond number of $5x10^{-4}$, and a differential pressure of 20.7 kPa was applied for the gasflood. A Corey representation of the data would give an oil exponent of 6. The gas relative permeability from the gasflood gave a Corey exponent of 2, using a endpoint gas relative permeability of 1 at the asymptotic S_{org}. Figure 4 gives an example of a high permeability core, permeability of 2100 mD. The k_{ro} from the gasflood is significant lower than the centrifuge data. The Bond number for the centrifuge run was $1x10^{-3}$, and the gasflood pressure was reduced to 4.1 kPa to compensate for the high permeability.

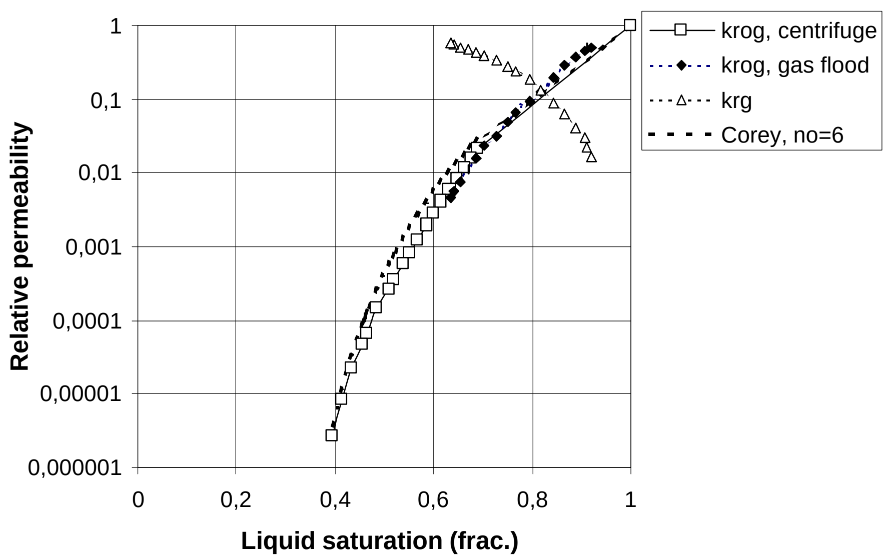


Figure 3. Gas-oil relative permeability for a 400 mD core, S_{wi} = 0.31.

Figure 3 and 4 reflect a general trend in the data, that k_{rog} for gravity drainage and gas flooding agree for low permeable cores, but deviate strongly at higher permeability. If the agreement between the two methods for relative permeability determination should be improved, a higher Bond number had to be applied for the centrifuge, and a lower differential pressure for the gas flood[20]. But the Bond number is already at the recommended upper limit[14] of 10^{-3}. If the oil relative permeability from gas flooding should be reduced a even lower applied pressure should be used, but from an experimental point of view the applied pressure is already low. It is the opinion of the author that these two methods for relative permeability determination should not be expected to agree. Gas flooding is viscous dominated and is known to create a discontinuous oil phase[31], while gravity dominated displacement in the centrifuge is stabilized and is expected to avoid oil film rupture and maintains a higher flowing fraction of the oil phase.

The agreement between centrifuge and flooding has been found to only be valid for k < 400 mD. The difference between centrifuge and gas flooding (constant differential pressure) is increasing with permeability. This behavior is systematic and there is no reason to say that core heterogeneity is a direct function of permeability, but it can not be ruled out. In the gas floods early gas breakthrough is observed and large saturation gradient along the core may be present. The centrifuge data more reflect the stable front displacement expected in this high permeable reservoir.

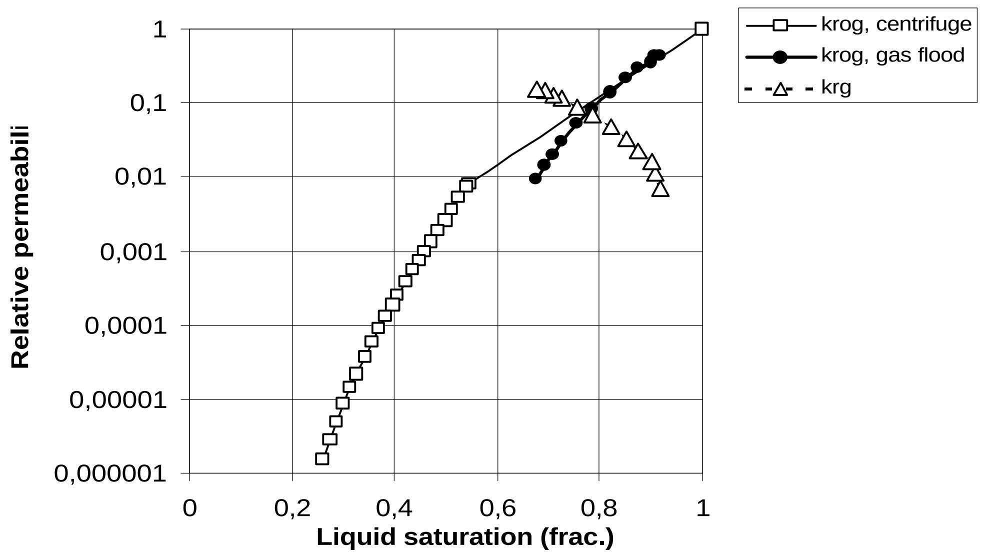


Figure 4. Gas-oil relative permeability for a 2100 mD core, S_{wi} = 0.18.

Residual Oil Saturation

The oil recovery by gas injection and waterflooding have been investigated in the laboratory by methods like; unsteady state (displacement), constant differential pressure (flooding) and centrifuge experiments. The centrifuge measured S_{org} is regarded as a lower limit of the remaining oil saturation in the reservoir. Usually the gravity stable gas injection experiments are influenced by capillary end-effects leaving a higher remaining oil than the residual oil saturation. Also these equilibrium gas injections are limited to a few pore volume throughput, and possible compositional effects may further reduce the oil saturation. For these reasons the long core gravity stable displacement is maybe an upper limit to the microscopic displacement efficiency in the field.

It has been recognized since many years (Terwillinger et al.[8], 1951) that recovery by gravity drainage is rate sensitive. Stability criteria[9,30] sets an upper limit for the gas rate to avoid viscous instabilities. These criteria are important guidelines for determination of residual oil saturation.

There are several different uses of the term residual oil saturation. The "true" residual oil saturation is often defined by the asymptotic value as k_{ro} goes towards zero. To achieve this S_{org} may require infinite time, and therefore a practical cutoff for k_{ro} defines a practical S_{org}, as an example, S_{org} @ kro=10^{-6} is used for the residual oil saturation. This procedure avoids the problem of extrapolating to k_{ro} equal to zero. Usually oil relative permeability below 10^{-4} is rare in the reservoir simulations, and some simulators even define
$k_{ro} < 10^{-6}$ as zero. Field simulation studies show that oil relative permeability as low as from 10^{-3} to 10^{-4} may be achieved during the field life. These results indicate that final oil saturation in the range of 0.1 could be obtained, see Fig. 2-4.

Another term used in core analysis is the remaining oil saturation, which may refer to the average oil saturation left in the core after a displacement. In gravity drainage, especially, the value of oil saturation near the top of the core, where the saturation is constant independent of vertical position is called the remaining oil saturation. This value of remaining oil saturation should be close, if not equal to, the residual oil saturation.

The statistical accuracy of gas - oil core flood measurements and comparison of different experimental methods have been discussed in a recent paper[20]. Several long core experiments have been performed using different types of injection gases. The mass exchange between non-equilibrium injection gas and reservoir oil at reservoir condition was found to shrink the remaining oil saturation by about 40 per cent. The core flood studying gravity drainage used equilibrium gas and oil, to be able to obtain relative permeability data. The correction of the residual oil saturation because of compositional exchange was treated independently. Generally, the residual oil saturation has been calculated from history match simulations of the experiments and extrapolation to a final endpoint was defined by a relative permeability cut-off value. The estimated residual oil saturation for core A was 0.08 in Figure 2, and would have been reduced to 0.05 if compositional effects were included.

Summary of the gas injection residual oil saturation shows variation in the range from .01 to .15 s.u., with an average residual oil saturation from long core experiments of about 0.1 s.u., for the Tarbert formation. Fewer experiments have been performed on the Oseberg-, Etive-, and Ness formation, but the data indicate a somewhat higher remaining oil. The efficiency of the gravity stable gas injection may depend on the pore structure of the rock. The pore size distribution and capillary desaturation curve have been reported earlier for ORE and Tarbert core material[32]. Gas residual oil saturation data from different formations of the Oseberg field have been compared from series of gas drainage centrifuge experiments.

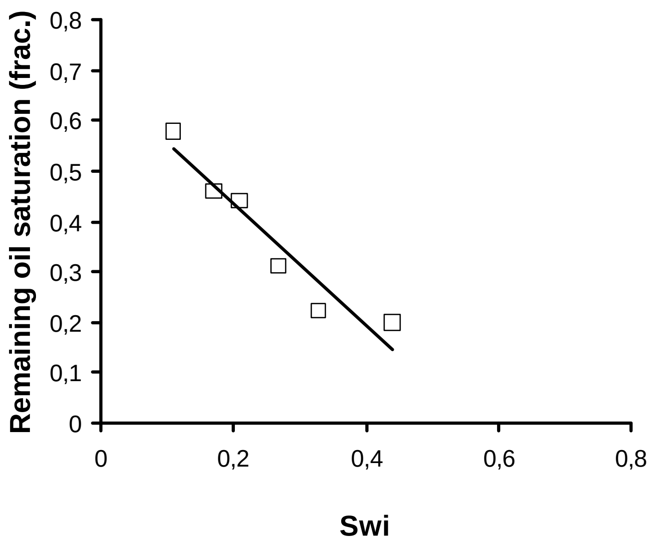
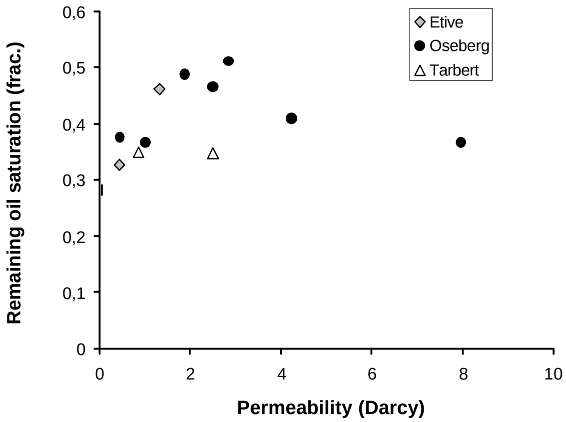


Figure 5. Remaining oil saturation after gasflooding versus initial water saturation, Oseberg formation cores.

An example of centrifuge core plug experiments is given by four Tarbert cores from well 30/9-B32. The cores had permeabilities of about 2 Darcy. The residual oil saturations by drainage in centrifuge at 3000 rpm were close to zero (fractions of .005 - .014). Due to these surprisingly low oil saturations, all cores were subjected to solvent extraction. The oil saturations after extraction were still very low (.015 – .03). The interfacial tension between oil and gas in the ambient centrifuge experiments is considerable higher than the interfacial forces in the reservoir. Centrifuge experiments represent a lower limit of residual oil saturation after a gas flood.

Data from remaining oil saturation from gasfloods are shown in Figure 5. The average oil saturation left in the core was increasing for lower the connate water saturation for these cores from the Oseberg formation. This means that, oil recovery is increased as connate water saturation increases. Similar observations have been seen in gravity drainage of outcrop cores[12,14,26], but have also been seen in reservoir core data[16]. Though, the wettability for Prudhoe Bay core material have been reported[33] to change to more oil wet at low connate water saturation, and this effect may give a stronger relation between residual oil and connate water.



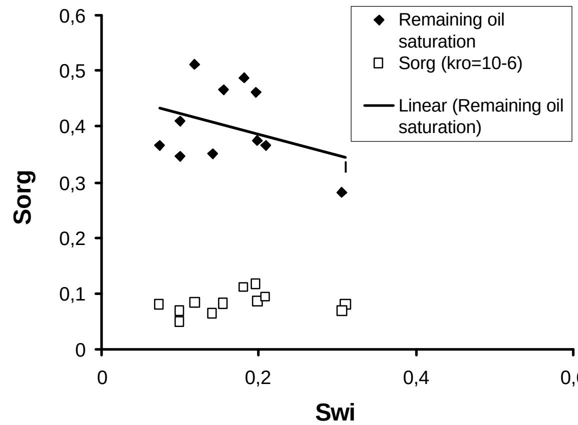
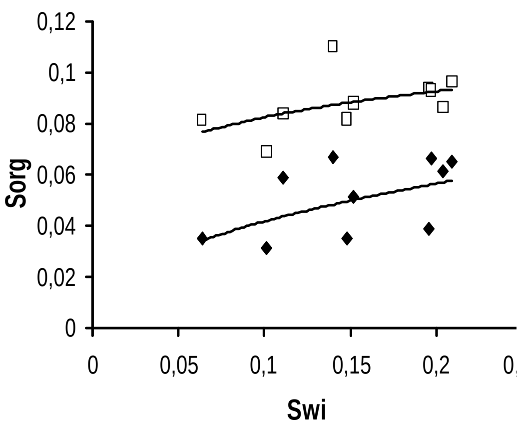


Figure 6. Remaining oil saturation after gasflooding versus core permeability

Figure 7. Remaining oil saturation and oil saturation, at kro of 10^{-6}, cores from Etive, Oseberg, and Tarbert formation.

There seems to be no direct relation between remaining oil saturation and permeability for this high permeable core material, Figure 6. Jerauld[16] found low oil recovery efficiency in the low permeable, fine grained sandstone or poor sorting sands at Prudhoe Bay. In another study of reservoir cores Edwards el al.[27] reported also for a high permeable reservoir (Ubit field) that S_{org} did not depend strongly on either rock properties or the initial water saturation. The remaining oil saturation after gas flooding of cores from different formations are compared S_{org} at a relative permeability of 10^{-6}, and Figure 7 indicate no trend in S_{org} versus S_{wi} at the extrapolated low S_{org} (extrapolated to 10^{-6} by Corey[22] relation)

Centrifuge drainage experiments from cores of the Oseberg formation are shown in Figure 8. Average remaining oil saturation and S_{org} at $k_{ro} = 10^{-6}$ both show the opposite trend of increasing S_{org} with S_{wi}. Centrifuge data for cores from the Etive formation show a weak tendency of increased S_{org} at low S_{wi}, Figure 9. A similar weak trend was also seen in centrifuge data from the Tarbert formation. The overall conclusion seems to be that the residual oil saturation does not have a unique trend versus either initial water saturation and permeability. The relationships are most likely more complex and may be influenced by variations in porosity, pore structure, and wettability.



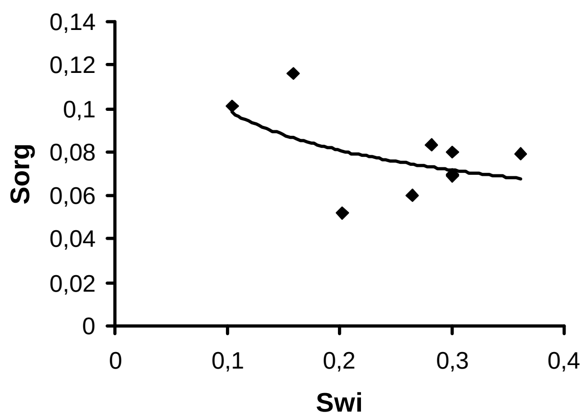


Figure 8. Average remaining oil saturation and

Figure 9. Sorg at kro:10-6, Etive formation cores.

Sorg at kro:10-6, cores Oseberg formation cores.

Comparing water and gas injection laboratory measured oil saturation at water breakthrough is on average around 0.4, while similar value for gas injection is 0.25. The average remaining oil saturation from waterfloods was 0.27. Both these results confirm the better efficiency of the gas injection compared to water.

Field measurement of remaining oil saturation. Remaining oil saturation (ROS) can be calculated from many different return signal from well tests; resistivity logs, pulsed neutron capture (PNC) logs, single well tracer tests, nuclear magnetic logs (NML), carbon/oxygen (C/O) logs, and electromagnetic propagation tool (EPT). All log determined ROS are porosity average oil saturation, while the single well tracer test gives a permeability weighted average. The different methods have been compared for waterflood ROS determination[34]. The ROS from single well tracer tests[35] is expected to give lower ROS due to high displacement efficiency in the more permeable fractions of the reservoir.

In addition, core analysis is a direct measurement of ROS in the laboratory by long core gas injection or by centrifuge capillary pressure and relative permeability measurements. Pressure cores have been applied to preserve the core at reservoir pressure until the core fluids can be immobilized by freezing. Sponge coring uses a sponge-sleeve made of a porous oil-wet polyurethane material to collect the oil bleeding from the core. By use of mass balance the total oil volume present can be calculated. Details of the Oseberg residual oil field measurements are given in references 18, 36, and 37.

Sponge core test. A sponge core test was performed on a 16 meter long interval in the Tarbert of well 30/9-B32. Details of the test is reported elsewhere[18]. The sponge core measurements used a series of single plug center piece cores. The sponge core data was regarded as not invaded by water. However, weak invasion of invaded mud filtrate is unavoidable and this may perhaps move some oil toward the center, resulting in a somewhat conservative residual oil estimate. The oil saturation seemed to increase with depth indicating oil saturation is still changing with time and further decrease is expected. Oil saturation was approximately 0.15 – 0.2 s.u . Centrifuge tests on some of the cores from the sponge coring gave much lower residual oil saturation (0-2 s.u.), showing that the sponge core data is far above the lower limit of residual oil by gas injection.

Waterflood single-well tracer test. Single-well tracer tests[35] to determine waterflood residual oil saturation have been applied in Oseberg on the Tarbert formation of well, B12A. Radial well treatments are difficult to compare to linear core floods. In the SWTT throughput and flow rate varies with radius. Injection rate was 1000 –1500 Rm3/d and total water injection was 20600 m3. The injection volume was supposed to be similar to a 50 pv throughput. The measured S_{orw} was 0.33. It should be mentioned that the oil saturation value obtained in the field is merely by viscous forces acting in the test zone and is not influenced by gravity forces. The field waterflood process benefit from gravity stable water displacement giving a positive contribution to the oil recovery efficiency. Unsteady state waterflood experiments measured remaining oil saturation of average 0.27, but significant lower oil saturations may be obtained over long time of production, as indicated by lower residual oil saturation from centrifuge experiments. Compared to gas injection, waterflooding is much less efficient.

Gas single-well tracer test. A similar single-well tracer concept was designed[37] to determine S_{org} after gas injection into the ORE formation of well, B03. The average permeability of the well area was 3 D. This well had earlier been an observation well in ORE, and the TDT-P log data had shown that the gas contact was below the bottom perforations. Though, the region should be close to a “true” residual oil saturation. Details of the tracer tests has been reported in ref. 37. The oil saturation was estimated from simulation of the tracer responses. A best match was obtained with S_{org} equal to 0.05, but the accuracy of the S_{org} value was poor, and in conclusion the test shows that the S_{org} must be lower than a saturation fraction of 0.1. This is comparable to remaining oil saturation from long cores, but is higher than residual oil saturation from centrifuge.

TDT-P log data. Several wells on Oseberg have served as observation wells in time periods before they were set into production. Iso-saturation maps have been calculated to describe and illustrate the sweep efficiency of the gravity stabilized gas injection. Especially have the TDT-P logs in deviated production wells acted as precursors for the gas front movement towards the horizontal wells located low on the structure, Figure 1. The use of gas front monitoring has been applied to balance the off-take from different zones of the reservoir. Other applications of the TDT-P logs have been to estimate the extent of gas cones at the production wells, and evaluate to what extent the gas saturation is reduced during shut-in. Coning occurs only in the near wellbore zone, but main part of the reservoir has a gravity stable displacement.

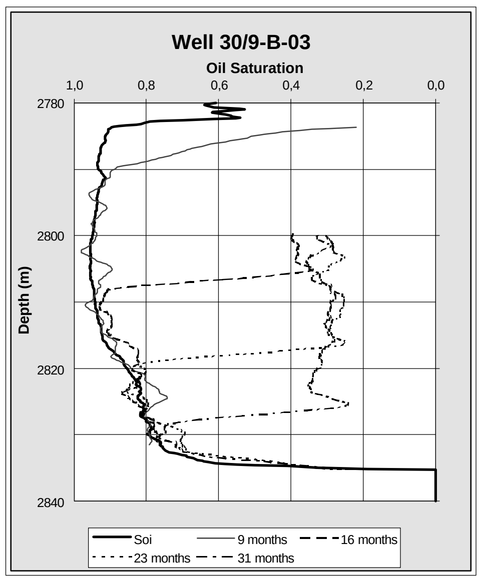


Figure 10. Saturation scans estimated from TDT-P log on well B-03.

TDT-P monitoring data from the wells 30/9-B-03, -07, -08 and 30/6-C25 was quantitatively analyzed with the purpose to determine TDT-derived residual oil saturation after gas flooding. Data interpretation is based on change of measured formation capture cross sections with time are exclusively caused by gas replacing oil. TDT derived ROS depends only on initial water saturation, porosity, difference of the capture cross section of oil and gas and finally the change of measured capture formation cross section.

The monitoring curves show very good description of the gas frontal movement, Figure 10, detected by a substantial decrease of the formation capture cross section. The analysis showed that after the gas front has passed, the measured formation capture cross section do not change with time. This indicates that within the actual limits of accuracy and the monitored time span, no additional drainage occurs after the gas front has passed. The analysis gave oil saturations average of about 0.35 s.u. for the three wells that are non-gas injectors in the Oseberg formation, while the oil saturation in well 30/9-B-07 that is an active gas injector in the Oseberg formation is substantially lower, ROS of about 0.2 s.u.. The uncertainty of oil saturation from TDT-logs was estimated to less than ±10% pv. Still, the oil saturations from TDT deviates from all other method of estimating remaining oil saturation. The oil saturation values from TDT logs are also inconsistent with reservoir simulations matching both the gas front movement and production from the reservoir. If oil saturation from TDT was correct, the oil reserves had to be adjusted significantly (unrealistic) to match front movement and production.

Conclusions

Laboratory studies found oil recovery by gas injection to be more efficient than waterflooding, field single-well tracer tests have confirmed these results.

Residual oil saturation estimated from laboratory measurements agrees with estimates obtained from field test measurements. Long core gas injection, centrifuge oil drainage experiments, and single well gas tracer tests, all gave an estimate of residual oil saturation of less than 0,1 s.u. for the Oseberg field.

Gravity drainage long core experiments had Corey exponent for oil relative permeability close to the theoretical values for gravity drainage process. Oil relative permeability from gas flooding experiments (constant differential pressure) deviated from centrifuge derived data at high permeability.

Gas front monitoring has confirmed stable gas front evolution at high oil production rates from the main reservoirs.

The laboratory generated special core analysis data have been successfully applied in the reservoir simulations, matching field data of gas frontal movement and oil production.

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