POTENTIAL EFFECTS OF CURRENT AND FUTURE DRILLING FLUID SYSTEMS ON CORE ANALYSIS

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ABSTRACT

The contamination of reservoir core samples by drilling fluid filtrate reduces the volume of rock for core analysis. Filtrate invasion causes changes in rock properties that potentially can affect core analysis measurements and, thus, reserve calculations. The objective of the study was to provide experimental data on the influence of drilling fluids on core analysis measurements and to raise consciousness on possible consequences.

Four drilling fluid systems were selected for investigations. The selection was based on statistical evaluations of the most frequently used drilling fluid systems in the Norwegian North Sea in the period from 1995 to 1997 as well as assumptions regarding the requirements of future field developments. The fluids comprised three water-based drilling fluids (WBM Carbonate, WBM Glycol, WBM Silicate) and one invert emulsion oil-based drilling fluid.

The study was performed on outcrop core material. The experimental set-up simulated aspects of rock/fluid interaction occurring during the coring of a reservoir on small scale (core plugs). Two lithologies, Blaxters sandstone and Liege Chalk, were investigated. Core plug samples were artificially restored with synthetic brine and crude oil to represent reservoir fluid saturations. Drilling fluid exposure experiments were performed at elevated temperature and pressure. To compensate for different filter loss properties, fluid exposure experiments lasted until 0.5 PV of mud filtrate had invaded the core plug sample. For each lithology a Special Core Analysis (SCAL) programme was performed as a "Baseline" study on undamaged/unexposed sample material and on material after the drilling fluid exposure experiment. The SCAL programme was extended by Nuclear Magnetic Resonance (NMR) Relaxometry and Magnetic Resonance Imaging to examine effects of the drilling fluids on NMR measurements and to characterise the local distribution of fluids in the core plug samples, respectively.

The study showed that under equal capillary endpoint pressure conditions the amount of oil recovery from core plugs is strongly affected by water-based filtrate residues. Results demonstrate a potential for miscalculations of the producible oil volumes and erroneously low reservoir producibility.

NMR-relaxation time measurements on core plug samples contaminated with different water-based and oil-based drilling fluids showed significant differences. Interpretations of NMR relaxation spectra affected by the invasion of water-based drilling fluid filtrate may lead to an underestimation of the free-fluid porosity as the relaxation times significantly shift to shorter values. Near wellbore zones in chalk formations invaded by oil-based drilling fluid filtrate would respond with a signal indicating larger oil volumes than actually present.

Further general conclusions of the study and recommended compensating measures are highlighted.

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INTRODUCTION

The invasion of drilling fluid into reservoir core samples is undesirable as it reduces the volume of uncontaminated rock for evaluation and may, in certain circumstances, preclude the measurements of important rock parameters (Donaldson and Clydesdale (1990)). Filtrate invasion affects the validity of measurements performed to determine *in situ* fluid saturations. Earlier studies have documented the effect of drilling fluid components on rock wettability (Sharma and Wunderlich (1985), Cuiec (1987), Hemphill and Mayes (1988)). Fluid saturations and wettability affect a range of core parameters (e.g. relative permeability, capillary pressure). These data are important for numerical simulations of field performance, the establishment of production strategies and for major investment decisions.

As a general guideline to minimise drilling fluid-related data quality problems obviously the best way to avoid interference would be to minimise, filtrate invasion. Although this can be achieved to a large extent through careful drilling fluid engineering, use of low invasion core bits, and suitable drilling parameters (see for example Rathmell et al. 1990, Tibbits et al. 1990 and Eaton et al. 1991), some contamination is bound to occur.

The interaction between drilling fluids and reservoir core samples is far too complicated to be covered comprehensively by any single project. In this work a focus was set on current and future drilling fluid systems on the Norwegian Continental Shelf identifying the extent to which data quality issues arise and working out practical solutions for how these problems can be avoided or remediated.

CURRENT AND FUTURE DRILLING FLUIDS ON THE NORWEGIAN CONTINENTAL SHELF

The following compilation is based on data obtained from the Norwegian Petroleum Directorate. During the period from 1995 to 1997 the drilling fluid systems listed below were used in exploration wells on the Norwegian Continental shelf. It should be noted that multiple drilling fluid systems may have been used within a single well.

	Number and % of wells
a) Water-base drilling fluid (WBM), no glycol added:	92 (60%)
b) Water-base, glycol-containing drilling fluid:	23 (15%)
c) Oil-base drilling fluid (OBM):	28 (18%)
d) Synthetic-base drilling fluid (SBM):	5 (3%)
e) Water-base, silicate-containing drilling fluid:	6 (4%)

Based on these statistics and on the expectation that synthetic-base drilling fluids will increasingly be replaced by oil-based drilling fluid, it was decided to concentrate the work on drilling fluid types a), b), c) and e) above. The latter (silicate-containing) drilling fluid was included as it was expected to play an important role in deep-water exploration wells and because there was relatively little experience with this fluid type so far.

Within each drilling fluid type, there will be significant variations in drilling fluid composition either between different suppliers, but also for suppliers internally. Compositions depend on the actual conditions for which the fluids are designed. There is also a steady development of drilling fluid systems and individual components.

METHODS

The guiding idea behind this work was to simulate a Special Core Analysis (SCAL) programme and NMR-core analyses on core plugs contaminated with water based and oil based drilling fluid filtrate, from the point in time where plugs are drilled from a reservoir core sample. Fig. 1 illustrates a core plug sample drilled from a reservoir core and shows how drilling fluid solids and filtrate are expected to contaminate such a sample. To simulate this situation, core plug samples were first drilled from an outcrop material and then exposed to a drilling fluid. Note, that under normal circumstances attempts are made to recover as much uncontaminated core material as possible from a reservoir core. The intention of the present study, however, was to create a defined contamination of the core material.

ROCK SAMPLES AND INITIAL PREPARATIONS

The study was performed on outcrop rock material. Two lithologies, Blaxters sandstone and Liege Chalk, were selected for investigations as they were petrographically similar to North Sea Jurassic sandstone and Creataceous chalk formations. Moreover, the material was consolidated and homogeneous, as well as available in sufficient quantity. In this way, similar conditions could be established for testing. For each lithology and for each drilling fluid tested, twin sets of core plug samples were prepared.

Core plugs (1.5” diameter, 2” length) were drilled using conventional laboratory coring tools and brine (50 000 ppm NaCl) as the cooling medium. Plugs were trimmed, cleaned by flooding methanol at room conditions and finally dried at 60°C. Chalk samples were stabilised using Teflon tape and shrink fit Teflon liners.

DRILLING FLUIDS AND DRILLING FLUID EXPOSURE EXPERIMENTS

Drilling fluid exposure was performed using four drilling fluid types (for compositions see Tab. 1):

1. WBM Carbonate (WBM C): water-based drilling fluid, with NaCl and $CaCO_3$
2. WBM Glycol (WBM G): water-based drilling fluid, with KCl and polyglycol,
3. WBM-Silicate (WBM S): water-based drilling fluid, with silicate and KCl ,
4. Oil based drilling fluid (OBM): invert emulsion drilling fluid with mineral oil as base fluid .

After oil saturation and preparation to S_{wi} by centrifuging, core plug samples were exposed to the drilling fluids under elevated temperature and pressure conditions (Tab. 2). The objective of the fluid exposure experiments was to inject, as exactly as possible, 0.5 PV of drilling fluid filtrate into the rock samples. Such a controlled volumetric filter loss was chosen to compensate for different filter loss properties of the fluids in later analyses.

Drilling fluid exposure experiments on sandstones were performed as dynamic filtration exposure experiments, i.e. with a cross flow across the endface of the core sample. An apparatus similar to that presented in van der Zwaag et al. (1997), yet, equipped with a special core holder for cylindrical plug samples was used. Experiments on chalk samples had to be performed as static filtration experiments, as the dynamic filtration core holder showed to be unsuitable for the soft and ductile rock material. A similar apparatus as presented in Oen et al. (1999) was used. Also, more moderate stress (pressure) conditions were selected when testing chalk (Tab. 2).

SPECIAL CORE ANALYSIS MEASUREMENTS

A dedicated Special Core Analysis (SCAL) programme for reservoir characterisation was performed both as a “Baseline” study on uncontaminated core plugs and on rock material after the

drilling fluid exposure experiment (Fig. 2). The baseline study comprised both a set of unaged and aged core plug samples (Fig. 2). Ageing was performed at elevated temperature (80°C) and pressure (10 bar) over two days to simulate a test history comparable to the samples that were exposed to the drilling fluids. The data evaluation focused on a comparison of baseline (identified as samples 5 and 6 in Fig. 2) and post-exposure measurements (Samples 1 to 4).

Before submitting them to the drilling fluid exposure experiments initial water saturation on core plug samples was established by centrifuging to S_{wi} in crude oil at 25°C. The oil had been filtered (0.45 µm) and degassed (at 60ºC) while brine had been filtered through 0.45 µm and degassed under vacuum. The formation brine used for the chalk samples had been equilibrated with small pieces of the rock over night at room temperature. Brine saturation of the contaminated (after exposure) and uncontaminated core plugs was controlled by (re-)saturating them with synthetic formation water under, alternately, vacuum and pressure. Brine permeability at room temperature was measured using a conventional flooding apparatus. Note that the brine permeability of the uncontaminated core plug samples represents the absolute brine permeability k_w, while the measurements on the contaminated samples were performed at an unknown mixed fluid saturation of oil, brine and drilling fluid filtrate. Note also, that the drilling fluid contaminated exposure faces of the core plug samples were trimmed off (approximately 10 mm) to avoid any influence of drilling fluid solids components.

Core plugs were then subjected to a standard Amott/USBM wettability test (cf. Anderson (1986)). A centrifuge speed of 7000 rpm for primary and secondary drainage and 4900 rpm for forced imbibition was selected for all materials. This represented a differential pressure of approximately 300±20 kPa. The volume of the produced fluids was measured and provided the basis to calculate

a) initial water saturation, S_{wi}, before spontaneous imbibition (Amott A)
b) residual oil saturation, S_{or}, after forced imbibition (Amott B)
c) irreducible water saturation, S_{wirr}, after forced drainage (Amott D).

Amott and USBM-indices were computed according to standard procedures. Also, a "mobile oil recovery factor" *(RF)* was calculated as the portion of the total oil that can be produced from the core plug at a defined pressure drawdown. Two values related to a) initial water saturation, S_{wi}, and b) irreducible water saturation, S_{wirr}, were calculated according to:

$$RF\ (300\ kPa) = (1-S_{wi(rr)}-S_{or})/(1-S_{wi(rr)})$$

After a complete sequence of drilling fluid exposure experiments and Amott/USBM tests, endpoint water saturations were measured by Dean Stark extraction and all fluid saturations were back-calculated. The sample material was then cleaned by flooding at 75°C using toluene and methanol. After drying at 60°C, helium porosity, grain density and Klinkenberg corrected gas permeability were measured using standard core analysis techniques.

NMR MEASUREMENTS

The SCAL programme was extended by Nuclear Magnetic Resonance Relaxometry (NMRR) and Magnetic Resonance Imaging (NMRI) to examine effects of the drilling fluids on NMR-data and to characterise the local distribution of fluid filtrate in the core plug samples after exposure, respectively. As in the SCAL programme, a "Baseline" on uncontaminated core plugs was established, both in brine and oil saturated state (at S_{wi}).

It has earlier been shown that NMR techniques yield information on changes in pore space properties and fluid saturations resulting from drilling fluid exposure (van der Zwaag et al., 1997, 1998). In this study NMRR was used to measure the NMR-porosity of the core samples and the mean

relaxation times T1 and T2, as well as to establish relaxation time distributions of the fluids in the core plugs. Relaxation time distributions correspond for brine saturated samples to the pore size distribution of the rock material (Straley et al. (1994)). Measurements performed on a core sample at mixed saturation (oil, brine, drilling fluid filtrate) can help characterising distinct features of fluid/rock interaction such as wettability alterations.

The twin set to the core samples used for the SCAL part of the study was successively:

(i) Saturated with brine (Baseline)
(ii) Centrifuged with crude oil to irreducible brine saturation (Baseline)
(iii) Exposed to complete drilling fluids (water-based or invert emulsion mud) and invaded by half a pore volume (0.5 PV) of drilling fluid filtrate.

In each saturation state, samples were subjected to NMRR measurements at 2 MHz and at 10 MHz proton resonance frequency. The longitudinal relaxation time T1 (spin-lattice-relaxation) was measured only at 2 MHz using the inversion recovery pulse sequence. The transverse relaxation T2 (spin-spin relaxation) was measured at 2 Mhz and at 10 MHz using the CPMG NMR sequence with an interecho time of 0.35 ms. T1 and T2 relaxation time distributions were calculated using a multi-exponential fitting routine based on a singular value decomposition algorithm.

Equivalent measurements were performed on bulk samples of the drilling fluids and the pore fluids. Of each fluid, a 15-gram sample, was analysed at 2 MHz and 10 MHz- proton resonance frequency.

NMRI is a spatially resolved measurement of NMR parameters (signal amplitudes, frequencies, relaxation times) using inhomogeneous time dependent magnetic fields superimposed to the static magnetic field of conventional NMR. NMRI is, thus, able to provide information on the spatial distribution of fluids in core samples or, as in this study, changes in the fluid distributions.

Non-slice selective 2d spin echo NMR images were acquired using an inter echo time of 2 ms. The image plane was oriented in the direction of the core flood, i.e. parallel to the core plug axis. By varying inter echo time, spatial differences in the relaxation behaviour of the pore fluid were monitored. These data were used to calculate relaxation time (T2) profiles of the core samples.

RESULTS

SPECIAL CORE ANALYSIS

Both outcrop sandstone and chalk samples were water-wet after storage in crude over 2 to 4 weeks without ageing (Tab. 4 and Tab. 5). Ageing for 48 hours at elevated temperature and pressure in crude oil changed the wettability of the Blaxters sandstone to close to “neutral” (e.g. Cuiec, (1987)), while Liege chalk remained water-wet. Exposure to some of the drilling fluids caused further, but relatively small, wettability changes in the Blaxters sandstone compared to the aged “Baseline”case. As could be expected, the OBM changed wettability to the most oil-wet extreme, albeit only with small margins compared to the other drilling fluid contaminated samples and still in the range of “neutral” wettability. The WBM Silica provided the most water-wet case.

For the chalk samples, a comparison of the initial water saturation S_{wi} before the spontaneous imbibition measurement and of the value after the termination of the complete Amott/USBM test sequence, showed large differences in all cases. Obviously, processes influencing the wettability of the Liege chalk appeared still to be ongoing at the time of the final measurements. This observation was also reflected by an increase in the mobile oil recovery factor during the Amott/USBM test (Tab. 5).

For three of the four drilling fluids used on chalk, it was not possible to decide whether wettability changes in the chalk samples were caused by drilling fluid filtrates or by ageing in crude at temperature and pressure. Only in the case of the sample exposed to the WBM C, spontaneous imbibition of brine was drastically reduced and the wettability changed from water-wet to slightly water-wet (Tab. 5).

The sandstone core plugs exposed to WBM C and WBM G showed a strong effect of the drilling fluid filtrate on the recovery factor. The mobile oil phase of these samples was significantly smaller than in the baseline case and the samples exposed to WBM Silica or OBM (Tab. 4). Results for the chalk samples show that the recovery factor strongly depends on timing within the Amott/USBM sequence. The recovery factor of the baseline samples and the samples exposed to WBM C and WBM G improves after secondary drainage. This means that the rock material gets more susceptible to oil during the Amott-test.

CHANGES IN NMR PROPERTIES

Baseline NMR-measurements on both sample materials are shown in Fig. 3(Liege Chalk) and Fig. 4 (Blaxters Sandstone). Note that the baseline NMR measurements were performed on unaged sample material.

Fig. 3 shows that the chalk at 100% brine saturation has T2 values ranging from 20 to 80 ms. This indicates a narrow, uniform distribution of relaxation times or a narrow pore size distribution (Howard and Spinler, 1993). Crude oil introduces a separate “oil peak” in the T2-distribution of the chalk at approximately the mean bulk relaxation time of the crude oil (450 ms). Obviously, the proton spins of the oil are not relaxed at the pore surfaces and the chalk remains water wet.

When the sandstone sample is saturated with oil to irreducible water saturation, it can be seen that the T2-distribution approaches longer relaxation times as the brine saturated sample. Although, the bulk relaxation time of the brine is significantly longer than the mean bulk relaxation time of the crude (Tab. 3), the introduction of oil causes a shift to longer relaxation times of the pore fluids in the rock sample (Tab. 4). Obviously, relaxation of the crude oil components is not significantly affected by the pore surfaces and it can be concluded that the unaged sandstone remains water wet in oil saturated state at S_{wi}.

Wettability observations on the uncontaminated, unaged rock materials correspond to the Amott/ USBM wettability measurements on the unaged materials performed in the core analysis part. No NMR-measurements were performed on the aged baseline rock samples. As such, all following comparisons of the samples after drilling fluid exposure to the baseline samples suffer from the absence of the wettability change observed for the SCAL samples. Ageing would probably have caused a shift in the NMR response to shorter relaxation times in the sandstone samples. SCAL data shows that the NMR-results for the chalk samples can be expected to be unaffected by ageing.

Changes in NMR-properties of the sandstone samples were largest for the WBM G drilling fluid. NMR-signal intensity (porosity) was lost and strong shifts to smaller mean T1 and T2 relaxation times were observed (Tab. 4). Changes were smaller for the samples exposed to WBM Silica and WBM C. In case of the OBM, NMR- porosity remained unaltered, while T1 and T2 relaxation times shifted to larger values even compared to the unaged baseline. Fig. 5 illustrates these observations by means of the relaxation time distributions of the core plugs partially saturated with OBM and the WBM G.

The shift in relaxation time and the loss of amplitude after drilling fluid exposure is related to the mean bulk relaxation time of the water based drilling fluids (Tab. 3). These are significantly

smaller than the values of the formation brine and the crude oil (Tab. 3). The oil-based drilling fluid is characterised by a mean T2 relaxation time larger than the value for the crude oil.

DISTRIBUTION OF FILTRATE IN CORE SAMPLES

NMR-Imaging (NMRI) provided visual evidence of the local distribution of drilling fluid components in the rock samples.

An interesting example was found in the NMR images of a Blaxters sandstone sample before and after exposure to the WBM C fluid. Fig. 7 combines the NMRI measurements on the same rock sample in three saturation states and presents the measurements of the local mean T2 as profiles along the core plug axis. The figure shows distinct, evenly distributed profiles over the length of the core plug in oil saturated state and brine saturated state, respectively. The measurement on the same sample exposed to the WBM C fluid (Fig. 7, lowermost profile), shows an uneven profile of T2-values. At the exposure end of the sample (right side in Fig. 7), T2 values are equal to the response of the brine saturated sample. The local mean relaxation time is then reduced in the direction of flow, approximately on the first 25% of the length of the core plug characterising a zone of filtrate invasion. At a distance of 10 to 12 mm from the exposure face, a minimum is approached. The local mean T2 increases from this point on and approaches the same value as the brine saturated sample after approximately 75% of the plug length. The last part of the sample has a T2 equivalent to the brine saturated sample. This observation was somewhat surprising. The result may give the impression that brine had accumulated at the outflow end of the core plug, maybe due to capillary end effects, while oil was completely displaced.

DRILLING FLUID FILTRATION PROPERTIES

OBM showed superior filter loss properties in both lithologies (Tab. 4 and 5). Among the water-based fluids WBM C showed the best filter loss properties.

DISCUSSION

ACCURACY AND REPEATABILITY OF MEASUREMENTS

The repeatability of the drilling fluid exposure experiments was not tested. Also, most analysis methods were not checked for repeatability. NMR-baseline measurements at 2 MHz on oil saturated (at S_{wi}) sandstone and chalk samples showed for example coefficients of variation of 2.2% and 6.3% for T2 measurements at 2 MHz on the two lithologies, respectively. These numbers indicate that measurements and preparation methods are repeatable and that the outcrop materials were homogeneous. .

SPECIAL CORE ANALYSIS

Wettability is a fundamental petrophysical parameter that affects most types of core analyses. In general, rock wettability controls phase saturations and multiphase flow in reservoir rock. Any change in the native rock wettability introduced through drilling fluid components can in final instance cause wrong estimates of reserve volumes and reservoir productivity as well as an incomplete or incorrect picture of the distribution of the reserves in a well.

Cuiec (1987) found earlier that oil-based drilling fluid greatly changes the wettability of core plug samples up to 1.5 cm from the contact surface. He points out that WBM causes almost no changes to wettability and finally, in contrary to Hemphill and Mayes (1988), concludes that OBM contaminated samples should not be used for special core analysis. Sharma and Wunderlich (1985)

demonstrated that many water-based fluid components induced only small wettability changes. However, all components investigated in their study altered wettability and permeability, sometimes significantly.

This study showed that the major part of the wettability changes of the Blaxters sandstone from water wet (WI_{Amott}=0.9) to neutrally wet (-0.3 < WI_{Amott} < 0.3, WI_{USBM} near 0) was caused by the crude oil during an ageing process. Small differences in the final wettability of the core samples after exposure may be related to the drilling fluids. The observations identify the oil-based fluid as the fluid changing wettability to the most oil-wet extreme. This is consistent with earlier research.

At equal endpoint capillary pressure, oil recovery from core plugs is strongly affected by water-based filtrate residues. The study demonstrates, thus, a potential for miscalculations of the producible oil volumes and erroneously low reservoir producibility, if drilling fluid filtrate is not completely removed from a reservoir core. The worst case was observed for the Blaxters sandstone contaminated by the WBM G. Significantly smaller amounts of oil were mobilised from this core plug sample. It is assumed that this was provoked either by a blocking effect caused by polymer deposits or by a water block-type of core damage. Water-based drilling fluid additives such as biopolymer (Xanthan), starch derivatives or cellulose are suspected to jeopardise Special Core Analysis and also NMR-Core Analysis measurements.

NMR-PROPERTIES

The study shows significant differences in NMR-relaxation time distributions of the pore fluids in the core plug samples partly contaminated with water-based and oil-based drilling fluid. The interpretation of such measurements is difficult and sometimes not unambiguous, since it is not always possible to distinguish between NMR signals from brine, crude oil and drilling fluid components. In particular it is demonstrated that the invasion of water-based drilling fluid filtrate may lead to an underestimation of the free-fluid porosity (Straley et al. (1994)) as the relaxation time spectrum shifts significantly to shorter relaxation times. Near wellbore zones in chalk formations invaded by oil-based drilling fluid filtrate would respond with a signal indicating larger oil volumes than actually present.

The water-based fluids investigated caused losses in signal intensity (porosity) and shifts to lower mean relaxation time values that are related to the low bulk relaxation time response of these fluids. The oil-based fluid caused changes in the opposite direction. Signal losses in sandstone samples through the introduction of polymer containing fluids have been observed in an earlier study (van der Zwaag et al., 1998). The confirmation of the earlier results through the observations in this project suggest, that water-based mud filtrate may contain significant amounts of substances causing mechanisms/reactions that reduce the proton spin relaxation of the pore fluids.

The SCAL-study showed a large impact of ageing at temperature and pressure on rock wettability. The fact that NMR-baseline measurements were performed on unaged rock samples obviously being more water wet than the samples exposed to the drilling fluids under simulated reservoir conditions, weakens the observations, but does not invalidate them.

DRILLING FLUID FILTRATE INVASION

Rock contamination from a simple volumetric point of view will be least using OBM. As this fluid has the best fluid loss control properties reflected by the longest exposure times to approach 0.5 PV filtrate invasion. As such it would be the preferred coring fluid in a formation that resembles the properties of the Blaxters sandstone or the Liege chalk.

To compensate for filtrate invasion, the degree of filtrate contamination in a reservoir core is frequently investigated by using iodide or bromide tracers as additives in the coring fluid before CT-scanning (Rathmell et al. (1990); Tibbitts et al. (1990); Trewin (1991)). Also, heavy water (D2O) or tritiated water are used to tag the aqueous phase of water-based or oil-based drilling fluids to quantify pore fluid contaminations and to provide reliable saturation measurements (e.g. Charlson et al., 1997).

CONCLUSIONS

Strictly speaking, the conclusions in this report are only valid for the data sets studied in the project. However, many of the conclusions will have more general validity, which needs to be confirmed through application in field work.

1. The major part of the wettability changes of the Blaxters sandstone from water wet to neutrally wet was caused by crude oil, and not by drilling fluids. Small differences in the final wettability may, however, be related to the drilling fluids. The observations identify the oil-based fluid as the fluid changing wettability to the most oil-wet extreme, which is consistent with earlier research.
2. Under equal endpoint capillary pressure conditions the amount of oil recovery from sandstone core plugs is strongly affected by filtrate residues of the WBM G and the WBM C. The study demonstrates a potential for miscalculations of the producible oil volumes and erroneously low reservoir producibility.
3. NMRR measurements clearly show effects due to the invasion of oil based or polymer containing water-based drilling fluid components. Their exact evaluation remains difficult. Especially the evaluation of NMR log data from the invasion zone should be accompanied with corresponding NMR laboratory measurements on core samples since otherwise there is a high potential for erroneous determination of the free and bound fluid porosities.
4. NMR-Imaging analysis provides unique information on the distribution of drilling fluid filtrate in core samples non-invasively. Such measurements are able to enhance the knowledge on core contamination and can therefore be an important tool for quality assurance in core analyses.
5. The techniques applied in this study are capable of efficiently detecting contaminations by drilling fluid components, successful removing these, and verifying the effect of core plug restoration.

RECOMMENDATIONS

1. Results point towards a strong influence of polymer containing filtrate on important core analysis measurements. The solubility of relevant polymers should be investigated and detailed cleaning procedures for core plugs contaminated with water based filtrate should be developed.
2. The “mobile oil recovery factor” is here suggested as an interesting analytical parameter on the same level as the “return permeability” to describe formation damage in reservoir rocks. The recovery factor as a laboratory parameter to describe formation damage through capillary pressure alterations may provide additional information in formation damage studies.
3. Water based or oil based filtrate contaminated core plug samples should be flushed intensively with formation brine and/or reservoir crude to reduce the effects of drilling fluid contamination. It is recommended to perform the following steps before starting core analysis:
   - Use preserved reservoir core samples.

- Collect information on the composition of the coring fluid. Be aware of potential effects.
- Perform CT-analyses on core plugs. Check for homogeneity and solids invasion.
- Drill plugs from the centre of the core sample, or if limited volumes are available, trim off cuts significantly larger than a zone of potential solids invasion.
- NMRI T2 relaxation time profiles along a core plug axis are recommended as a rapid check for quality control of core plug samples. Such profiles may help to detect contamination through non-native fluids.

4. For NMR-log interpretation it is important that the core analysis program provides accurate baseline information. The core plugs used for calibration measurements should have minimal damage. Potentially contaminated core-plugs should be cleaned and restored. To provide reliable data for NMR-log interpretation and at the same time gain valuable information on factors influencing core analyses, it is recommended to perform NMR-relaxation time measurement on core plugs drilled from reservoir cores successively in
   - native/fresh state
   - cleaned and restored state
   - cleaned, restored and artificially contaminated state
   - brine saturated state
   - de-saturated state

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FIGURES AND TABLES

Tab. 1. Composition of drilling fluids.

Water-base, NaCl with CaCO3 (1.3 S.G.)			**Water-base, KCl with glycol (1.3 S.G.)**	
Sodium Chloride	250 kg/m^3		Xanthan Gum	3 kg/m^3
Xanthan Gum	5 kg/m^3		Polyglycol component	30 l/m^3
Starch derivative	10 kg/m^3		Potassium Chloride	115 kg/m^3
Sized CaCO3	95 kg/m^3		Barite	320 kg/m^3
Sized CaCO3 fine	165 kg/m^3		Polyanionic Cellulose	12 kg/m^3
Water	4.1 m^3		Water	4.1 m^3
Water-base, silicate (1.3 S.G.)			**Oil-base**	
Xanthan Gum	2 kg/m^3		Organoclay	15 kg/m^3
Silicate	30 kg/m^3		Primary emulsifier	20 l/m^3
Potassium Chloride	75 kg/m^3		Secondary emulsifier	8 l/m^3
Barite	2000 kg/m^3		Calcium Chloride	15 kg/m^3
Polyanionic Cellulose	10 kg/m^3		Barite	360 kg/m^3
Water	4.2 m^3		Lime	20 kg/m^3
			Base oil	2.9 m^3
			Water	1.1 m^3

Tab. 2. Test conditions for drilling fluid exposure experiments.

Setup Parameter	Chalk	Sandstone
Drawdown / Differential pressure	15 bar	50 bar
Consolidation / overburden pressure	40 bar	100 bar
Mud injection pressure	25 bar	80 bar
Pore pressure	10 bar	30 bar
Temperature	80°C	80°C
Filtration conditions	static	dynamic

Tab. 3. ^{1}H NMR (T2 , 2 MHz) characterisation of bulk pore fluids and drilling fluids samples.

Sample	Amplitude	Mean T2	Sample Weight
		(ms)	(g)
Crude Oil	31764	446	15.00
SFW Sandstone	25663	6502	15.00
SFW Chalk	26472	5500	15.00
OBM	28851	888	15.02
WBM C	30196	126	15.02
WBM G	30877	97	15.01
WBM S	28465	163	15.01

Tab. 4. Major results of the measurements performed on the Blaxters Sandstone.

Lithology		**Blaxters Sandstone**					
Mud system		**WBM Carb.**	**WBM Glycol**	**WBM Silica**	**OBM**	**Baseline**	**Baseline**
Blaxters Sample ID		**A4279.10**	**A4279.07**	**A4279.01**	**A4279.03**	**A4279.04**	**A4279.08**
Petrophysical measurements							
Brine Permeability k_w	(mD)	108	74	84	97	113	147
S_{wi}	(frac.)	0.17	0.16	0.17	0.20		
Filter Loss							
Avg. exp. time to approach 0.5 PV filtrate invasion	(min)	108	36	30	570		
Petrophysical measurements							
S_w postflood/brineflood**	(frac.)	0.72	0.76	0.77	0.63	1.04	0.99
Brine permeability, $k_w(S_{or})$	(mD)	83	43	33	122	(aged)	(unaged)
S_{wi} (before Amott A)	(frac.)	0.17	0.22	0.17	0.15	0.17	0.17
S_{or} (after Amott B)	(frac.)	0.37	0.44	0.21	0.20	0.38	0.20
S_{wirr} (after Amott D)	(frac.)	0.15	0.15	0.13	0.11	0.16	0.16
Wettability indexes							
WI_{Amott}		0.04	0.10	0.25	-0.02	0.14	0.90
WI_{usbm}		0.08	-0.33*	0.29	-0.18	1.29*	0.29
Oil recovery at equal cap. pressure							
Mobile oil recovery factor, initial S_{wi}	(frac.)	0.55	0.44	0.75	0.76	0.76	
Recovery efficiency		72 %	58 %	98 %	100 %	100 %	
Mobile oil recovery factor, final S_{wi}	(frac.)	0.56	0.48	0.76	0.77	0.76	
Recovery efficiency		73 %	63 %	99 %	102 %	100 %	
Standard core analysis							
Length	(cm)	4.29	4.41	3.96	4.05	5.10	5.14
Diameter	(cm)	3.73	3.74	3.74	3.74	3.74	3.75
Helium porosity	(%)	20.3	19.7	19.5	19.9	20.4	20.1
Pore Volume	(ml)	9.4	9.4	8.4	8.7	11.1	11.3
Air permeability	(mD)	234	177	143	191	103***	206
Blaxters Sample ID		**A4279.05**	**A4279.02**	**A4279.09**	**A4279.06**	avg. of 4	Baseline
NMR measurements						(Oil sat., unaged	(brine sat.)
2 MHz Porosity	(%)	17.0	13.8	16.1	18.7	18.5	20.5
10 MHz Porosity	(%)	17.8	12.2	16.1	20.1	19.3	18.7
2 MHz Mean T1	(ms)	82.3	56.8	154.4	473.7	270.5	251.1
2 MHz Mean T2	(ms)	48.3	31.4	100.1	217.7	188.4	139.9
10 MHz Mean T2	(ms)	21.8	41.0	67.3	120.4	84.4	87.2

* capillary pressure curves show irregularities and make the interpretation of the USBM index faulty

**backcalculated from endpoint brine saturation ***low value, unknown reason

[1] Amott wettability index: $0.3 \le WI_{Amott} \le 1.0 \Rightarrow$ water-wet, $0.3 > WI_{Amott} > 0.1$ slightly water wet, $0.1 \ge WI_{Amott} \ge -0.1 \Rightarrow$ neutral/mixed wettability, $-0.1 > WI_{Amott} > -0.3 \Rightarrow$ slightly oil-wet, $-1 \le WI_{Amott} \le -0.3 \Rightarrow$ oil-wet

[2] USBM wettability index: WI_{USBM} near $1 \Rightarrow$ water-wet, WI_{USBM} near $0 \Rightarrow$ neutrally wet, WI_{USBM} near $-1 \Rightarrow$ oil-wet

Tab. 5. Major results of the measurements performed on the Liege Chalk.

Lithology		**Liege Chalk**					
Mud system		**WBM Carb.**	**WBM Glycol**	**WBM Silica**	**OBM**	**Baseline**	**Baseline**
Liege Sample ID		**4258.10**	**4258.01**	**4258.12**	**4258.13**	**4258.16**	**4258.11**
Petrophysical measurements							
Brine Permeability	(mD)	2.7	2.5	2.5	2.1	2.0	2.2
S_{wi}	(frac)	0.50	0.49	0.48	0.51		
Filter Loss Control							
Avg. exp. time to approach 0.5 PV filtrate invasion	(min)	2944	81	507	25631		
Petrophysical measurements							
S_w postflood/brineflood**	(frac.)	0.87	0.80	0.75	0.79	1.04	0.97
Brine permeability, $k_w(S_{or})$	(mD)	0.9	0.8	0.6	0.5	(aged)	(unaged)
S_{wi} (before Amott A)	(frac.)	0.53	0.53	0.51	0.52	0.59	0.86*
S_{or} (after Amott B)	(frac.)	0.23	0.27	0.26	0.25	0.05	0.18
S_{wirr} (after Amott D)	(frac.)	0.30	0.32	0.37	0.41	0.40	0.49
Wettability indexes							
WI_{Amott}		0.22	0.62	0.75	0.74	0.91	0.60
WI_{usbm}		0.61	1.06	0.9	1.05	1.8	1.3
Oil recovery at equal cap. pressure							
Mobile oil recovery factor, initial S_{wi}	(frac.)	0.51	0.42	0.53	0.53	0.61	
Recovery efficiency		84 %	68 %	87 %	86 %	100 %	
Mobile oil recovery factor, final S_{wi}	(frac.)	0.67	0.60	0.58	0.57	0.71	
Recovery efficiency		95 %	84 %	82 %	80 %	100 %	
Standard core analysis							
Plug Length	(cm)	4.13	4.22	3.43	3.55	5.31	5.00
Plug Diameter	(cm)	3.72	3.73	3.72	3.72	3.72	3.70
Helium porosity	(%)	43	43	43.4	42.5	42.9	43.3
Pore Volume	(ml)	19.3	19.8	23.7	22.8	24.8	23.4
Air Permeability	(mD)	2.7	5.0	2.1	2.3	2.3	2.6
Liege Sample ID		**A4258.05**	**A4258.02**	**A4258.03**	**A4258.09**	**avg. of 4**	**Baseline**
NMR measurements						(Oil sat., unaged	(brine sat.)
2 MHz Porosity	(%)	43.3	41.5	43.2	39.2	43.4	42.5
10 MHz Porosity	(%)	41.5	42.5	44.9	38.2	42.2	43.9
2 MHz Mean T1	(%)	NA	101	84.4	154.4	105.1	54.7
2 MHz Mean T2	(%)	NA	65.2	47.8	117.2	87.9	34.9
10 MHz Mean T2	(%)	30.9	36.0	35.2	71.8	48.4	27.0

*extremely high value by unknown reason

[1] Amott wettability index: $0.3 \le WI_{Amott} \le 1.0 \Rightarrow$ water-wet, $0.3 > WI_{Amott} > 0.1$ slightly water wet, $0.1 \ge WI_{Amott} \ge -0.1 \Rightarrow$ neutral/mixed wettability, $-0.1 > WI_{Amott} > -0.3 \Rightarrow$ slightly oil-wet, $-1 \le WI_{Amott} \le -0.3 \Rightarrow$ oil-wet

[2] USBM wettability index: WI_{USBM} near $1 \Rightarrow$ water-wet, WI_{USBM} near $0 \Rightarrow$ neutrally wet, WI_{USBM} near $-1 \Rightarrow$ oil-wet

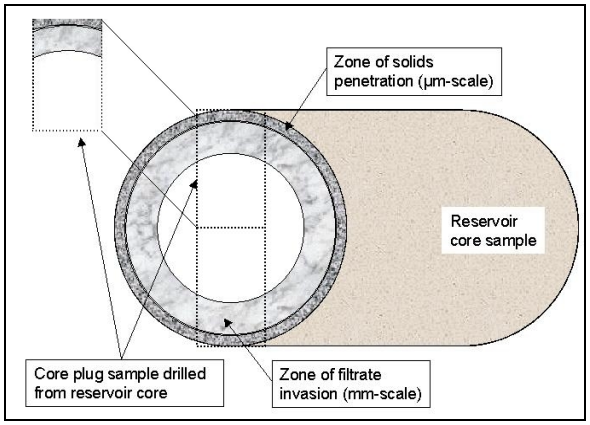

Fig. 1. Reservoir core sample covered and invaded by drilling fluid solids and invaded by drilling fluid filtrate.

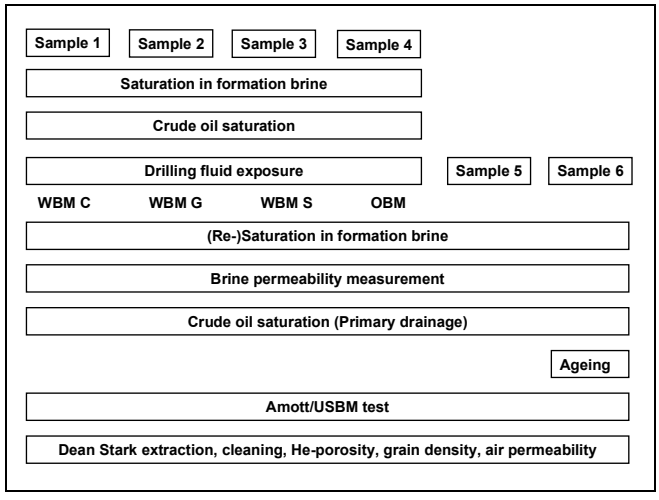

Fig. 2. Flow chart of the SCAL-programme.

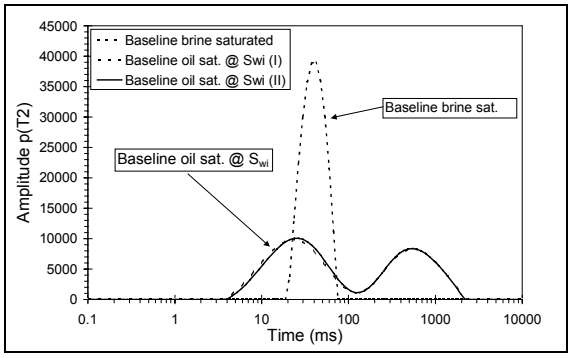

Fig. 3. ^1H (2 MHz) -NMR, T2 relaxation time distributions of Liege Chalk in brine saturated and oil saturated (at S_{wi}) state.

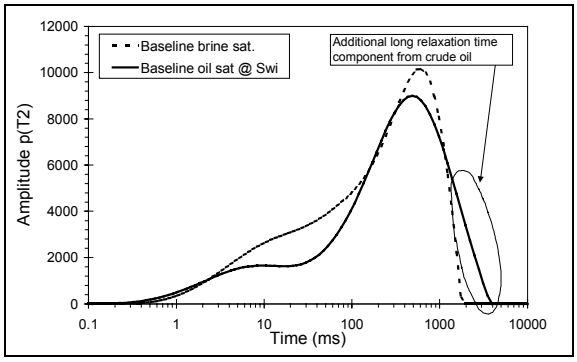

Fig. 4. ^1H (2 MHz) -NMR, T2 relaxation time distributions of Blaxters Sandstone in brine saturated and oil saturated (at S_{wi}) state.

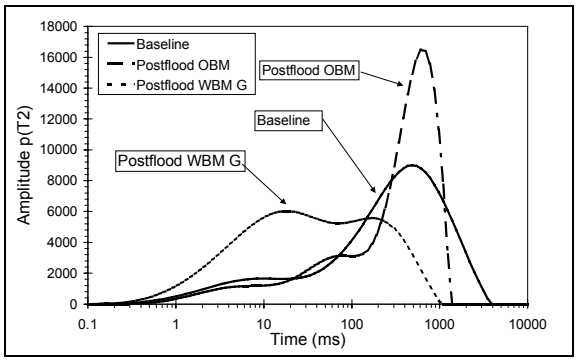

Fig. 5. ^1H (2 MHz)-NMR T2 relaxation time distributions of sandstone samples after exposure to the oil-based fluid and to the WBM Glycol.

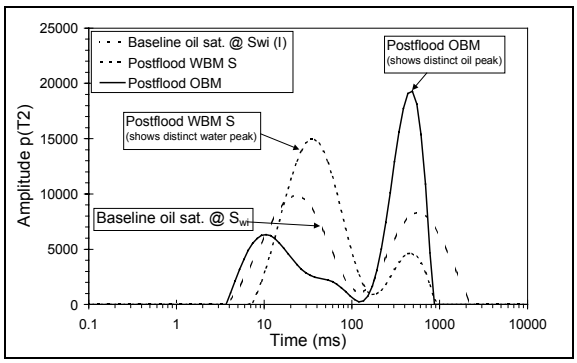

Fig. 6. ^1H (2 MHz)-NMR T2 NMR Relaxation time distributions of chalk samples after exposure to the oil-based fluid and to the WBM Silicate.

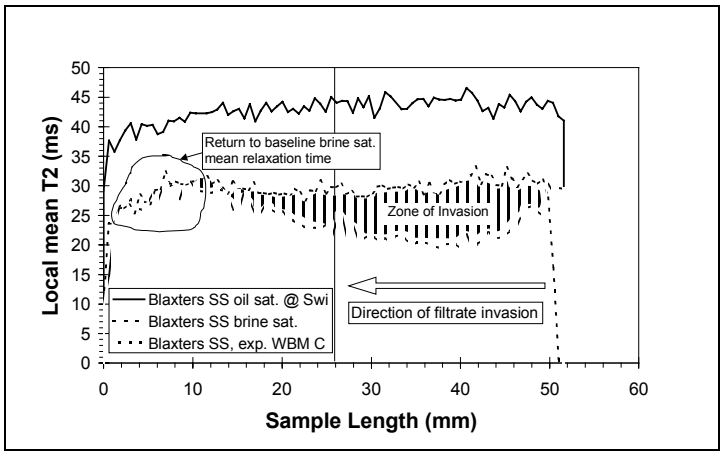

Fig. 7. Locally resolved ^1H (10 MHz) NMR T2 profile of the Blaxters sandstone, brine saturated and before and after exposure to WBM Carbonate.