COMPATIBILITIES AND INTERACTIONS

Section B11
Compatibility with Shale

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B11.1 Introduction

The problem of wellbore instability in shales is one of the largest sources of lost time and trouble cost during drilling. Operational problems that derive from such instabilities range from high solids loading of the mud requiring dilution, to hole cleaning problems due to reduced annular velocities in enlarged hole sections, to full-scale stuck pipe as a result of well caving and collapse [1]. Although borehole stability problems can be problematic in oil-based and synthetic-based muds, the main problem area lies with water-based muds. Adverse interactions between water-based muds and troublesome shales have lead to the development of a whole range of additives that are supposed to serve as shale inhibitors in water-based muds. Many of these additives are shale specific and others are limited to certain operating conditions. Some inhibitors may be useful for stabilizing cuttings, but may also have no effect, or even an adverse effect, on actual borehole stability.

Fluids based on potassium and cesium formate brines are amongst the best shale stabilizing water-based drilling and completion fluids currently available. Unlike other water-based drilling and completion fluids, the shale stabilizing properties of formate fluids are attributable to the inherent properties of the formate brine itself rather than to the additives. This has the great advantage that the shale stabilizing properties do not deplete with time, and no complicated and / or expensive maintenance is required.

B11.2 Shale instability mechanisms

Before we can understand how formate brines help to stabilize shales, we first need to understand the mechanisms that destabilize shales, and how these problems are mitigated. Full explanations of the mechanisms involved in shale instability and shale stabilization are beyond the scope of this document. An excellent overview of stability in shales and the mechanisms involved is given by van Oort [1]. To fully understand the benefits formate brines can give to shale drilling, the reader is highly recommended to read this publication.

This document presents brief descriptions of the different mechanisms involved in the three types of shale problems: 1) borehole instability, 2) cuttings instability, and 3) bit balling. An understanding of the mechanisms is important in order to understand the shale stabilizing effects of formate brines that are described later.

B11.2.1 Borehole instability

The number one requirement for borehole stability is the use of correct mud weight. The use of a correct mud weight ensures that near-wellbore stresses are kept in check and do not overcome formation strength. For weak formations, such as reactive shales, this means that the fluid in the borehole is at overbalance and initially applies a supportive radial compressive stress to the borehole wall. In this scenario, the hole is stable directly after drilling and only becomes unstable if mechanical and chemical changes take place in the shales lining the borehole.

The main cause of borehole instability problems not originating from the use of incorrect mud weight is the pressure build-up caused by the hydraulic flow of water into the shale. The Darcy flow of incompressible water-based filtrate into the high-stiffness shale matrix gives rise to a pressure invasion front that causes elevated pore pressures in an extended zone around the wellbore. This increased pore pressure could theoretically be compensated by a reduction of swelling pressure of a similar magnitude [1]. However, in practice, this is impossible as swelling-reducing additives (ions) invade the shale section around the wellbore at a much lower rate than the pressure front. For low-permeability shales, the pore-pressure front is expected to exceed the ion diffusion front by one to two orders of magnitude [1]. **Therefore, traditional shale inhibitors (inhibitors that stop swelling) cannot prevent borehole stability problems created by filtrate invasion that leads to pressure invasion.**

Borehole stability problems caused by Darcy flow of filtrate into the shale can only be mitigated by shutting off or slowing down the filtrate influx. This effect, of reducing filtrate flow into shales, can be achieved by:

- Increasing the filtrate viscosity.
- Stimulating an osmotic back-flow of pore water from the shale into the wellbore. (By successfully stimulating an osmotic back-flow of pore water, one can actually increase the strength of the wellbore [1][2]).
- Lowering the shale permeability (pore blocking).

A combination of these techniques is often applied.

B11.2.2 Cuttings instability

Cuttings instability differs from wellbore instability in that as soon as the cutting is released from the rock matrix, the in-situ stresses are suddenly removed and replaced by the uniform mud pressure. The reduction of mud pressure (hydrostatic pressure) as the cuttings travel up the annulus allows the shale swelling pressure to become dominant, which may now overcome the cementation's strength and separate the clay platelets by drawing water from the mud.

Cutting instability problems can be reduced by:

- Inhibition and encapsulation. The traditional inhibitor for swelling of reactive shales is the potassium ion, K^+. Certain high molecular-weight polymers, such as PHPA, normally achieve encapsulation.
- Shut-off of the water influx by filtrate viscosity enhancement, pore blocking, or stimulated osmotic backflow of pore fluid.

B11.2.3 Bit balling

Bit balling is a poorly understood phenomenon that is usually approached on a trial-and-error basis by empirically testing additives for their effect on ROP. There are many factors involved in bit balling unrelated to the fluid. Bit balling occurs because of the stress release that occurs in the cutting immediately after the cutting is generated. This stress release means that hydration is triggered, and water is drawn from any available source, including the surface of the drill bit and other nearby cuttings. In drawing water inwards, cuttings may 'vacuum' themselves onto the bit and each other, causing the bit to ball. Bit balling can be avoided by designing the drilling fluid to either increase or lower the water content of the clay. By increasing the water content, the cuttings might be made to disperse, but this could give rise to an unwanted build-up of fine solids in the mud.

As the 'danger zone' for bit balling (the zone where the water content is in the intermediate level, where it causes bit balling problems) depends on the type of shale, its specific clay type and clay content, and therefore its swelling pressure, it is difficult to predict in advance whether or not the actual fluid is prone to cause bit balling problems.

If bit balling is known to be a problem in a specific shale, one solution is to design the drilling fluid so that the cuttings are dehydrated. This can be accomplished by using a mud system that builds membranes and osmotically dehydrates the shale.

B11.3 How formate brines stabilize shale

Formate brines, especially cesium and potassium formate brines, have some unique inherent properties that can assist in stabilizing shales and therefore limit shale drilling problems, such as borehole instability, cuttings dispersion, and bit balling. These properties are 1) brine (filtrate) viscosity, 2) osmotic effect, 3) presence of inhibiting cations (K^+, Cs^+), and 4) presence of the formate anion. These properties and their role in stabilizing shales are discussed here.

B11.3.1 Brine (filtrate) viscosity – provides borehole and cuttings stability

As described in section B11.2, restricting the flow of incompressible water (filtrate) into the shale slows down the pressure invasion front that causes elevated pore pressures to build up in the area around the wellbore. According to Darcy's law, the rate of flow of fluid in a porous medium is inversely proportional to the viscosity of the fluid. Therefore even small increases in filtrate viscosity can be significant for shale stability: when filtrate invasion is causing shale instability, then an increase in filtrate viscosity by a factor of two will increase trouble-free openhole time by the same factor [1]. Many water-based drilling fluids are based on very low salinity brines like *KCl* that have a viscosity close to that of water.

Concentrated brines have a much higher viscosity. Concentrated cesium and potassium formate brines have viscosities of five to twelve times that of water. (See Section A4 Brines Viscosity). This makes a significant impact on the rate of flow of these formate brines into the shale and thereby on the pressure invasion that causes borehole instability. Please note that it is the base fluid (filtrate) viscosity that provides this benefit and not the bulk viscosity of the drilling fluid that originates from drilling fluid viscosifying additives.

The importance of the filtrate viscosity to restrict the Darcy flow is particularly important in shales containing micro-fractures that are non-responsive to stabilization by osmotic effects (i.e. membrane efficiency = 0).

B11.3.2 Osmotic effect – provides borehole and cuttings stability

Darcy flow of fluid into the shale can be compensated for by an osmotic flow from the shale and back into the borehole (see B11.2.1). The magnitude of this back-flow depends on the type of shale and the water activity of the drilling fluid. Testing has shown that low permeability matrices of intact clay-rich shales can act as imperfect or 'leaky' membranes that sustain osmotic flow of water [3]. Concentrated cesium and potassium formate brines and their blends have very low water activities (about 0.3). See Section A3 Water Activity and Colligative Properties. The water activity of concentrated sodium formate is not quite as low (about 0.5). Sodium formate, and especially diluted sodium formate fluids, are therefore not as efficient in generating such an osmotic back-flow as concentrated cesium and potassium formate brines and their blends. Depending on the water activity and the type of shale, the osmotic back-flow can be strong enough to strengthen the borehole by lowering the pore pressure and water content of the shale [1] [2].

The benefits that concentrated formate brines have in stabilizing the wellbore are described well by van Oort [1] and Chenevert [4][5]. Van Oort [1] writes: "Especially potassium formate (*KCOOH*) seems especially suitable for shale drilling by reducing swelling pressure, shale water content and pore pressure at the same time". Professor Chenevert of the University of Texas, Austin, USA presents the swelling pressures, membrane efficiencies (reflection coefficients), and shale strength results for eleven tests performed on Speeton shale with various fluids. Detailed information is provided on the experimental technique, types and quantities of analytical equipment used, and results for each phase of each test. The report [4] concludes: "The strength tests show that shale strength can be maintained when 0.40 a_w *KCOOH*, and 0.78 a_w MEG fluids are used. In addition, the strengths are reduced by 25 to 35% when 1.0 a_w de-ionized water, 0.40 a_w $CaCl_2$, 0.78 a_w $CaCl_2$, 0,78 a_w Glycerol, and 0.78 aa_w *NaCl* / MEG fluids are used. There is yet another paper by Chenevert [5] that highly recommends potassium formate to be field tested as a shale drilling fluid due to the high osmotic effect. The paper states: "Two fluids stood out in their ability to restrict flow into the Speeton shale and also maintain shale strength. They were the ionic Potassium Formate and the non-ionic Methyl Glucoside solutions".

B11.3.3 K^+ and Cs^+ cations – provide cuttings stability

It is well known that presence of potassium ions (K^+) reduces swelling in certain types of shales (montmorillonite type shales). The effectiveness of the K^+ ion in minimizing swelling pressures in montmorillonite is believed to be due to the small amount of hydration of these ions in water, resulting in low ion repulsion. Other ions such as Mg^{2+} and Ca^{2+} are not as effective as the K^+ ion in reducing the swelling pressure in montmorillonite [2]. Testing has confirmed that the cesium ion (Cs^+) has the same advantageous effect as potassium on shale swelling. Both potassium and cesium formate brines therefore have inherent swelling inhibition properties. The sodium ion (Na^+) does not have the same effect on swelling pressure, and when drilling through reactive shales it is therefore advised to use potassium formate or potassium / sodium formate blend rather than pure sodium formate.

B11.3.4 Formate ion – provides cuttings stability

Laboratory testing and field experience show that the formate ion itself assists in stabilizing certain shale types. Hallman [6][7] reports the outcome of extensive testing and field experience with using low concentration (5–10%) potassium formate drilling fluid in Alberta and British Columbia, Canada. The primary problem shales in this area are the Blackstone, Fernie, and Fort Simpson. Hallman's laboratory testing and field experience with various potassium brines (potassium chloride, potassium sulfate, potassium formate) with similar potassium levels suggest that the formate ion itself must have a positive effect on swelling inhibition.

B11.4 Shale stability with formates – laboratory test results

Three types of shale stability tests are commonly referred to in the oilfield literature. These are:

- Pressure transmission testing.
- Shale swelling testing.
- Shale dispersion testing.

Pressure transmission tests require advanced equipment and good quality confined core samples. Only a proper pressure penetration test can evaluate the fluid's ability to provide borehole stability.

Shale swelling and dispersion tests are simpler tests. These tests do not use confined shale samples and they do not apply a pressure differential across the shale sample. These tests are therefore not suited for predicting wellbore stability, but when performed on proper shale samples, fully saturated with pore fluid, can give good indications of the fluid's ability to prevent cuttings swelling and disintegration during transit up the annulus. When performed on dried out shale samples, such tests have no value as the outcome is only a function of the fluid's bulk viscosity.

Some typical test results from these various test methods are presented below.

B11.4.1 Pressure transmission testing with formates

Pressure transmission tests are proper downhole simulation tests that are used to predict wellbore stability by monitoring the pressure build-up inside of the shale formation surrounding the wellbore. They require the use of well-preserved shale samples without micro cracks and the use of realistic confining pressures.

The pressure transmission test was originally developed by Shell Research in the Netherlands [8], but today a whole range of laboratories are equipped to perform simple pressure transmission tests.

An extensive explanation of the principle of the pressure transmission test is beyond the scope of this document. A full explanation of the test is given by van Oort [8].

In short, the principle of the test is as follows (see Figure 1): A shale core sample is placed in contact with two separate fluid reservoirs. The downstream reservoir contains shale pore fluid. The upstream reservoir may contain pore-fluid or mud, depending on the test type. Prior to testing, the sample is equilibrated to confining stresses, temperature, and pore-pressure (by pre-pressuring the reservoirs). Overbalance is applied at the upstream reservoir at the start of the test and the rate of the downstream pressure change, representative of pore-pressure change experienced by the sample, is subsequently measured.

As shale samples vary in permeability, testing is first carried out with pore fluid in both reservoirs to establish permeability. Subsequent tests are then run with test fluid in the upstream compartment.

Pressure transmission tests have been carried out on a 72%wt potassium formate brine and low permeability Eocene shale in the Downhole Simulation Cell (DSC) at the laboratory of O'Brian-Goins-Simpson & Assoc., Inc. [3] [9]. More detailed information on the DSC test procedure can be found elsewhere [10].

The Downhole Simulation Cell (DSC) test is a large-scale drilling test where an actual borehole is drilled into a field-cored shale sample that is submitted to realistic downhole confining stresses, fluid pressures, and temperature. Mud at a characteristic over-balance is circulated into the well for a 72-hour period, during which time changes in strains and fluid pressures are monitored. At the end of the test, the mud pressure is lowered (to simulate a pressure swab) until shale failure occurs, indicated by a sudden and noticeable change in strain values. Post-mortem analysis of the shale core is performed to assess the degree of damage by mud filtrate invasion, shale strength monitoring, water content, and change in ionic composition from the wellbore outward into the sample.

A 72%wt potassium formate mud was tested in the DSC along with three other reference muds. Low-permeability Eocene shale was used under the following conditions: P_{axial} = 26.5 MPa, P_{radial} = 19.0 MPa, P_{mud} = 17.5 MPa, P_{pore} = 13.0 MPa, T = 77°C. The pressure differential over the shale sample (overbalance) was 4.5 MPa (= P_{mud} - P_{pore}).

The results of the test are shown in Table 1. Figure 2 shows the relative changes in pore-pressure during the DSC tests for the four fluids studied.

The results show that for seawater / Lignosulphonate and *KCl* / PHPA muds there was a considerable increase (~2 MPa) in pore pressure after the 72-hour circulation period. This indicates that mud invasion and pressure penetration had destabilized the shale, resulting in hydrated and softened near-wellbore zones and a relatively high mud

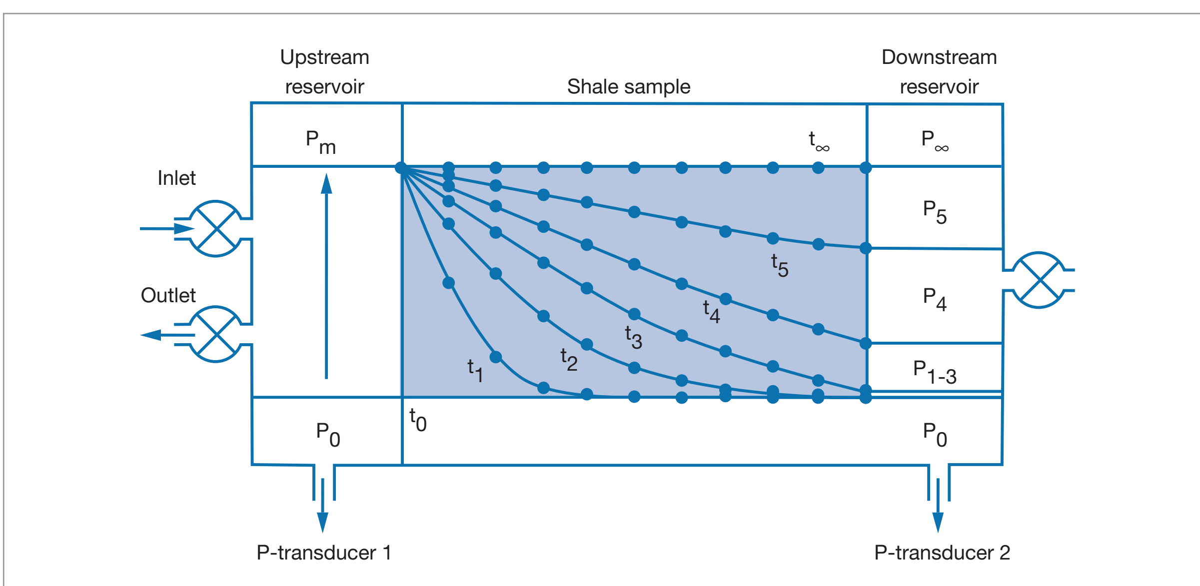

Figure 1 Schematic representation of the pressure transmission apparatus and pressure propagation with time [8].

Table 1 Results of DSC test reported by van Oort et al [3].

Drilling fluid	Water activity	Change in P_{pore} [MPa]	P_{mud} at failure [MPa]	Water content %				Shale activity			
				Bore	¼–1"	1–2"	Core	Bore	¼–1"	1–2"	Core
Seawater / lignosulphonate	0.88	+2.2	12.4	11.3	10.8	10.7	10.3	0.87	0.85	0.85	0.84
KCl / polymer	0.93	+1.8	12.4	11.1	11.0	10.6	10.2	0.93	0.90	0.88	0.84
25% *$CaCl_2$* IOEM	0.73	-1.7	6.2	9.9	10.0	10.0	10.2	0.76	0.83	0.84	0.84
72% *KCOOH*	0.38	-2.2	5.5	7.4	9.2	10.1	10.4	0.78	0.80	0.85	0.86

pressure at failure. By contrast, the result with IOEM (oil-based mud) showed a reduction of pore pressure, dehydration and strengthening of the near-wellbore zone, and much lower mud pressure (stronger swab) at failure. In this test, the wellbore was much stronger than in the case of the seawater / Lignosulphonate and *KCl* / PHPA mud. The potassium formate mud showed a result similar to the IOEM: reduction of pore pressure (by 2.2 MPa), dehydration and strengthening of the near-wellbore zone, and a strong wellbore indicated by a low value of the mud pressure at failure during swabbing.

The DSC results for potassium formate mud are readily explained by osmotic backflow. The 72%wt potassium formate fluid has a very low water activity (A_w=0.38) and thereby generates an extremely high osmotic pressure ($\Delta\Pi$ ~ 150 MPa). This means that the effective pressure stimulating osmotic backflow of shale pore water, $\sigma\Delta\Pi$, would have been significant for this mud even for small values of membrane efficiency, σ. The membrane efficiency for Eocene shale was estimated to be 0.05, i.e. a 5% efficient membrane. The DSC results for potassium formate show clearly that the effective osmotic pressure (estimated at $\sigma\Delta\Pi$ ~ 7.5 MPa) exceeded the hydraulic overbalance (ΔP = 4.5 MPa), leading to a net dehydration and lowering of pore pressure, which was found to benefit shale strength and stability. Similar effects have been observed for concentrated sodium formate and cesium formate fluids [9].

B11.4.2 Dispersion testing with formates

FracTech Ltd. has carried out 16-hour dispersion tests in three drilling fluid systems to compare their performance in London clay [11]. Dispersion tests are suitable for predicting stability of cuttings as they are performed with unconfined shale samples and do not allow for the pressure invasion front that causes wellbore instability. These tests are normally carried out for no more than 16 hours, which is significantly more than the time it normally takes for the cuttings to reach surface.

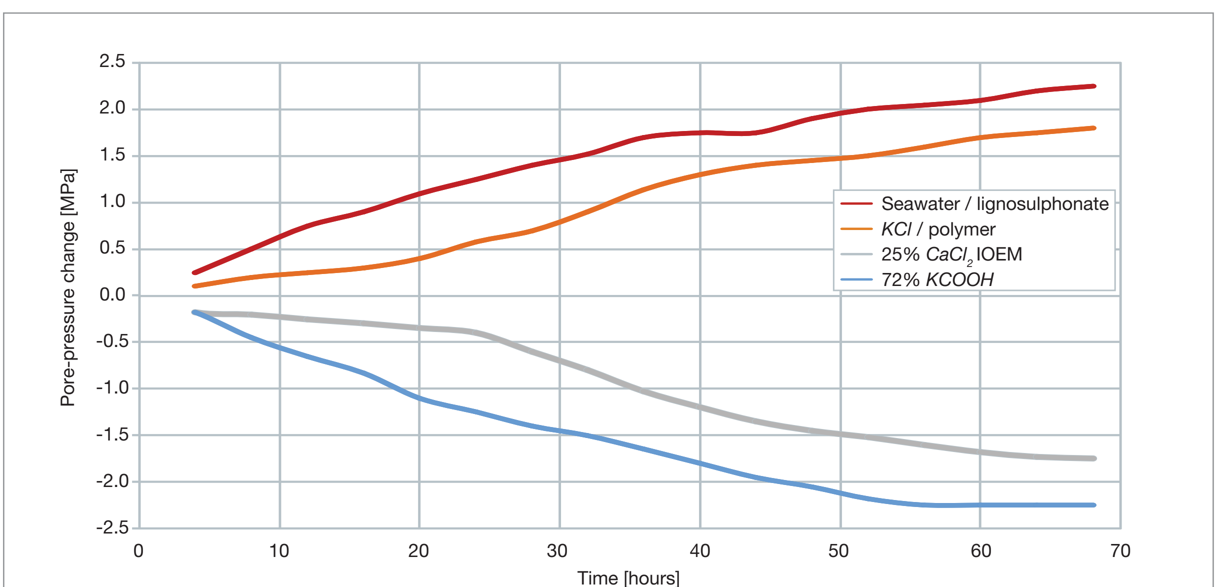

Figure 2 Relative change in pore-pressure during DSC tests [3].

The three fluid systems tested were:

- 1.62 s.g. / 13.5 ppg potassium formate drilling fluid
- 1.62 s.g. / 13.5 ppg cesium / potassium formate drilling fluid
- 1.60 s.g. / 13.3 ppg high-performance clouding glycol shale drilling fluid.

All muds were hot rolled at 65.6°C / 150°F for 16 hours before use.

Dispersion testing was carried out with 100 mL mud and approximately 10.0 g of 2–4 mm London clay chips. The test bottles were rolled for 16 hours with the rollers rotating at 20 rpm. They were then cooled before opening. The contents of each bottle were poured over a 0.5mm sieve (of known weight) and the cuttings irrigated briefly with tap water to remove excess drilling fluid. Care was taken not to wash the chips away. The sieves were placed into an oven at 120°C / 248°F to dry the chips to constant mass. A sample of unexposed chips was weighed and also dried to determine the clay's water content.

The percentage of clay recovered was calculated, making a correction for the water present in the original clay:

$$\%_{recovery} = \frac{S2\text{-}S1}{(1\text{-}Y/100)} \times X \times 100\% \qquad (1)$$

Where:

X = Mass of shale in bottle
Y = Original moisture content of shale [%]
$S1$ = Mass of empty sieve
$S2$ = Mass of sieve + shale after drying

The dispersion results are shown in Table 2. The percentage dispersion in the formate fluids was in the range 1–2% compared to 7% in the clouding glycol mud.

Table 2 FracTech dispersion test results for three drilling fluids with London clay [11].

Mud type	% solids retained	Dispersion [%]
KFo **1.62 s.g. / 13.5 ppg**	99	1
KCsFo **1.62 s.g. / 13.5 ppg**	98	2
Clouding glycol mud 1.60 s.g / 13.3ppg	93	7

B11.4.3 Linear shale swelling testing with formates

FracTech Ltd. has carried out 16-hour linear swelling tests in three drilling fluid systems to compare their performance in London clay [11]. Linear swelling tests are suitable for predicting stability of cuttings as they are performed with unconfined shale samples and do not allow for the pressure invasion front that causes wellbore instability. These tests are normally carried out for no more than 16 hours, which corresponds to the time it takes for the cuttings to reach surface.

The three fluid systems tested were:

- 1.62 s.g. / 13.5 ppg potassium formate drilling fluid.
- 1.62 s.g. / 13.5 ppg cesium / potassium formate drilling fluid.
- 1.60 s.g. / 13.3 ppg high-performance clouding glycol shale drilling fluid.

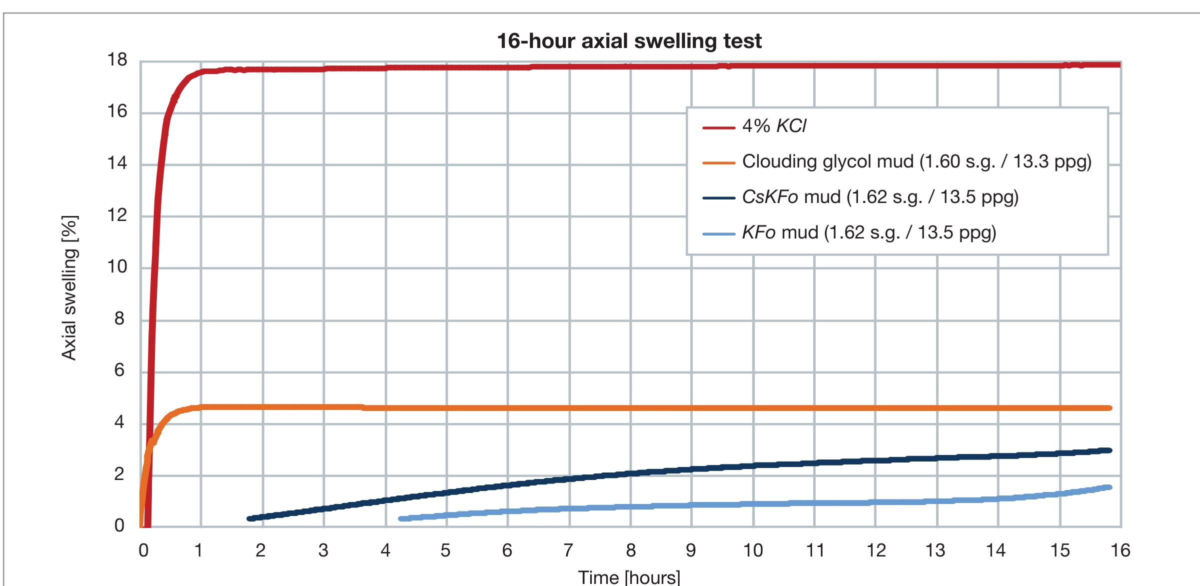

Figure 3 16-hour axial swelling test performed on three different mud systems at 160°F. As can be seen, the swelling in both of the two formate muds is significantly lower than in the 4% *KCl* solution and in the high-performance clouding glycol-based shale drilling fluid.

All muds were hot rolled at 65.6°C / 150°F for 16 hours before use.

Linear shale swelling was measured on rectangular 20 mm long cross-sections of London clay. The sides of the sample were scraped to reveal a fresh surface. The amount of axial expansion or contraction of the sample was measured with a LVDT displacement transducer placed on top of the shale sample. The plug was heated to test temperature (65.6°C / 150°F) and kept for 15 minutes before drilling fluid at 65.6°C / 150°F was circulated through the test cell at a rate of 5 mL/min. A fourth test was carried out with 4% *KCl* as a baseline (the traditional WBM shale drilling fluid of 20 years ago).

Figure 3 shows the amount of swelling measured in the four fluids as a function of time. With the 4% *KCl* baseline fluid, the clay sample showed significant early time swelling approaching 18% within two hours and then remained at this level. In both formate fluids the clay sample showed significantly lower swelling rates than the clouding glycol-based mud system. The results therefore indicate that both formate fluids are significantly more inhibitive than the specially designed clouding glycol shale drilling fluid. After 16 hours the swelling of the shale sample in the potassium formate brines was still <10% of the sample exposed to the *KCl* brine.

B11.5 Shale stability with formates – field experience

There are plenty of examples of shale drilling applications where both high-density and low-density formate muds have shown excellent stabilizing properties. Examples of applications reported in the open literature are:

B11.5.1 Agip S.p.A, South Italy

Agip S.p.A used potassium formate and potassium acetate to drill eleven wells through very plastic shales in south Italy [12]. Careful monitoring of drilling performance and drilling fluid properties was conducted in order to compare these new mud systems with their traditional *KCl* polymer mud. The new mud systems that contain only 2–4%wt potassium salt showed remarkable improvements to ROP and drilling-related problems. The paper reports the following savings:

- ROP increased from 6 m/h to 12 m/h.
- Time spent on bit balling or shale plugs reduced by 77% per 1,000 m drilled.
- Time spent in reaming reduced by 68% per 1,000 m drilled.

In addition, Agip experienced a 14% reduction of the mud volume per hole volume, which together with an improved management of mud disposal operations, contributed to a 60% reduction in waste produced per hole volume.

B11.5.2 Agip Norge, Barents Sea

A 1.30 s.g. / 10.8 ppg potassium / sodium formate drilling fluid was used to drill the shale sections of two exploration wells (Goliath and Gamma) in the Barents Sea [13]. Due to environmental restrictions, a water-based fluid had to be used. On the subject of shale stability, the paper states:

- Goliath: "Cuttings from the actual reactive zones were sent to a laboratory for comparative inhibition tests against the glycol-based system used elsewhere in the Barents Sea. Analysis showed a higher degree of inhibition with the potassium formate brine system."
- Gamma (drilled with re-used formate mud): "The quality of the cuttings was similar to those generated by a theoretically more inhibitive oil-based drilling fluid. Near the end of the second consecutive well in which it was run, the conditioned 10.8 lb/gal system still exhibited a superb rheological profile, suggesting excellent hole cleaning and wellbore stability properties."
- The condition of the drilling fluid at the conclusion of Gamma was excellent, with only 5% solids content. The fluid was stored without filtration and will be used on another Barents Sea well."

B11.5.3 Statoil, Huldra

Six HPHT reservoir sections were drilled and completed with cesium / potassium formate brine in the Huldra field [14]. The paper states: "In addition the experiences are positive with respect to hole cleaning, hole stability, and ECD."

B11.5.4 Statoil, Kvitebjørn and Valemon

Berg et al. [15] report the drilling and completion of seven long deviated HPHT reservoir sections with a 2.015 s.g. / 16.8 ppg cesium / potassium formate drilling fluid in the Kvitebjørn field. Five wells were completed with stand-alone sand screens and two were completed with a cemented, perforated liner. The Kvitebjørn high-angle reservoir sections contained long sequences of shales (50 / 50% shale and sand).

No washouts were experienced in any of the wells during drilling through long sections of interbedded shales in the Kvitebjørn reservoir (50 / 50% shale and sand) with the cesium / potassium formate fluid. A variety of shale and sand sections were exposed to the drilling fluid, ranging from the organic-rich shale above the reservoir (Viking group), through the heterogenic Brent group (comprising

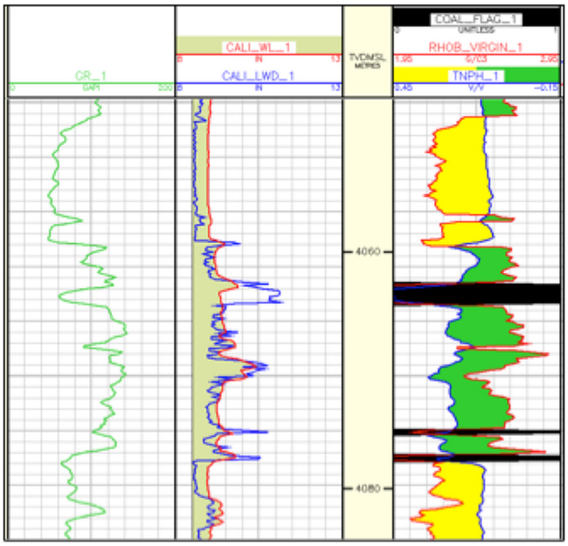

Figure 4 Mechanical caliper (CALI_WL) run 10 days after LWD ultrasonic caliper (CALI_LWD) in the Ness reservoir zone of Kvitebjørn well A-11. The Ness reservoir zone is interbedded with coal layers and shale sections.

sand, shale, and coal) to the deep marine shale in the Drake group. The only hole-enlargements occurred, as expected, in the coal sections. Both acoustic caliper logs while drilling and mechanical caliper logs from wireline logging are available on several wells. There is a slight difference in the average hole size between these measurements, but no major increase in hole size can be seen from the time of drilling to wireline logging a couple of weeks later. Examples of calipers are shown in Figure 4 for the Ness reservoir zone, which is interbedded with coal layers and shale sections, and in Figure 5 for a Draupne overburden shale section in the Valemon exploration well. In the first example, the borehole had been open for ten days from the time the LWD log was run to the time the wireline log was run. In the second example, the time between the two logs was as long as 30 days. Even after a few weeks of open hole in Kvitebjørn and Valemon, hole-sizes over 9.5 inches have been very rare, both in intra-reservoir shales and overburden shales.

Since the paper was written, another five wells have been drilled in the Kvitebjørn field without mud-related shale problems.

B11.5.5 KerrMcGee, China

The paper describes laboratory testing of several fluids, and field experience with a sodium formate / *KCl* fluid [16]. The paper states: "The length of the openhole horizontal production interval ranged from 495 to 600 m. These intervals were drilled with no hole-stability problems, minimal fluid losses, and with good ROP."

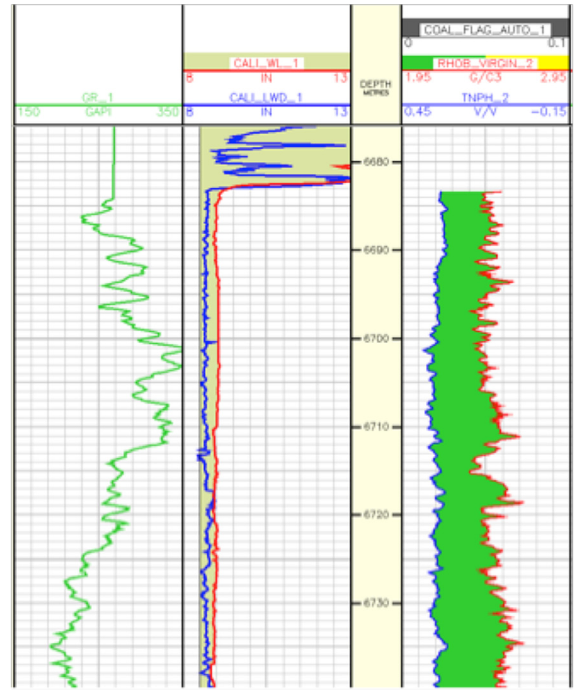

Figure 5 Mechanical caliper (CALI_WL) run 30 days after LWD ultrasonic caliper (CALI_LWD) in the overburden hot shale of the Viking group and into the rat hole (6,683m.). The well inclination is 63°.

B11.5.6 Alberta, Canada

Over 200 wells have been drilled with a formate / biopolymer mud in Alberta, Canada, with improved results over previous muds used [6]. In Alberta the Fernie and Blackstone shales cause significant difficulty in drilling operations. When the traditional fluids were replaced with 5–10% potassium formate mud the shales were completely stabilized, and the beneficial effect remained even when the formate fluid was displaced to fresh water. It was shown that this stabilization did not occur at similar or higher potassium levels with potassium chloride or potassium sulfate, indicating a beneficial effect from the formate anion, not just the potassium ion. Drilling operations were improved, total drilling time was reduced, and the resulting production was excellent.

B11.6 Use of shale stabilizing additives in formate brines

Since 1993 potassium and cesium formate brines have been used in hundreds of wells to drill troublesome shale sections and reservoir sections interbedded with shales (see B11.5). Numerous field case histories published over the past 17 years suggest that the physical and chemical properties of formate brines minimize the risk of failure of boreholes and shale cuttings. For this reason there has never been a need to use shale stabilizing additives in formate brines. Without this driver very little effort has been put into identifying shale-stabilizing additives compatible with formate brines.

A complete overview of the various types of shale-stabilizing additives, and how they work in conventional fluids, is given by van Oort [1]. A short description of these additives is given here along with what little we know about their compatibility with formate brines.

One group of chemicals that can be added to drilling and completion fluids to increase their shale stabilizing properties is **salts**. Salts work by providing cations for swelling inhibition, increasing viscosity, and lowering water activity to promote osmotic back-flow. Salts known to have shale stabilizing properties are [1]: KCl, $NaCl$, $CaCl_2$, $ZnCl_2$, $MgCl_2$, $MgBr_2$, $ZnBr_2$, *Na* formate, *K* formate, *Cs* formate, *Na* acetate, *K* acetate, *Cs* acetate.

Both the anion and cation of the monovalent formate brines provide all of the beneficial properties listed above (strong swelling inhibition from Cs^+ and K^+, high filtrate viscosity, and very low water activities). Consequently there is nothing to gain by adding non-formate salts to formate fluids. The addition of some of these salts can only contribute to the deterioration of other fluid properties, such as reservoir compatibility and corrosion.

The shale stabilizing properties of formate brines can however be optimized by adjusting the balance of monovalent cations in the fluid. When sodium formate brine is being used, it could be beneficial to provide some K^+ ions in the fluid to improve its shale-swelling inhibition properties. This can be achieved by adding some potassium formate. Likewise a sodium and potassium formate brine blend may have better shale stabilizing properties than a diluted single-salt potassium formate brine due to its increased filtrate viscosity. In potassium and cesium formate blends it is also possible to 'adjust' the water activity if a higher water activity level is required. This can be achieved by replacing some potassium formate with cesium formate and water (see Section A5 Water Activity and Colligative Properties).

Certain types of **polymers** (e.g. cations, amines, PHPA) are also believed to have shale-stabilizing properties. These are polymers with functional groups that adsorb onto clay surfaces at multiple sites, and are suited for providing cuttings stability. Depending on the molecular weight, these might either penetrate into the shale and prevent shale swelling, or they may latch onto the outer surfaces of the shale (e.g. PHPA). As concentrated formate brines already contain plenty of shale-swelling inhibition from K^+ and Cs^+ ions, such additives have nothing additional to offer.

MEG (Methyl Glucoside) has been identified as a good shale stabilizer for both wellbore and cuttings as it increases the filtrate viscosity and lowers the water activity of the fluid. Concentrated formate brines provide exactly the same benefits, for the same reasons. Chenevert [4][5] tested both a concentrated potassium formate and a MEG-based fluid and found them both to be equally good at stabilizing shales due to their high filtrate viscosities and low water activities.

Polyglycerols and polyglycols (commonly referred to as just glycerols and glycols) are often added to water-based shale drilling fluids. The low molecular weight versions help to viscosify the filtrate and therefore contribute to both cuttings and wellbore stability. The higher molecular weight versions are screened out on the surface of the shale and are therefore not believed to be very useful [1]. Concentrated formate brines provide high filtrate viscosity without the use of additives. It is also possible to 'adjust' the filtrate viscosity of formate brine blends by manipulating their composition. For example, blends of sodium and potassium formate have a higher viscosity than single-salt potassium formate brine at the same density.

Another group of polyglycols are the **clouding glycols** or TAME (thermally activated mud emulsion) [17]. These polyglycols have the ability to phase-separate (cloud out) when they reach a certain temperature. The mud is engineered such that the CPT (cloud point temperature), which is a function of glycol type and salinity, will be reached inside of the shale, but not inside of the wellbore. When these polyglycols phase separate and emulsify inside of the shale they effectively block further fluid invasion.

Due to the high salinity of concentrated formate brines, commonly used clouding polyglycols have been shown to cloud out at ambient temperature. Cabot Specialty Fluids is unaware of any clouding polyglycols compatible with concentrated formate brines.

Soluble silicates are occasionally used as shale stabilizers in water-based muds. When they come in contact with the pore water in the shale, precipitation (with divalent cations) and gellation (from reduced pH) form a barrier to further filtrate invasion. The barrier formed by gelled and precipitated silicates prevent any further mud filtrate invasion and pressure penetration. The silicate barrier also forms efficient osmotic membranes that allow osmotic dehydration of shale and thereby increase stability. Soluble silicates are therefore often used in conjunctions with monovalent brines that provide reduced water activity.

Some attempts have been made to identify silicates compatible with concentrated formate brines. However, all attempts have resulted in precipitation taking place at ambient conditions.

B11.7 Shale stability in low-density formate brines

As mentioned in section B11.3, formate brines, especially cesium and potassium formate brines, have some unique inherent properties that assist in stabilizing shales. These properties are 1) brine (filtrate) viscosity, 2) osmotic effect, 3) presence of inhibiting cations (K^+, Cs^+), and 4) presence of the formate anion. The first two of these properties (filtrate viscosity and osmotic effect) are dependent on brine concentration. When water is added to formate brines, brine viscosity decreases and water activity increases. The increase in water activity lowers the osmotic effect. Therefore, one would not expect low-density / diluted formate brines to have the same excellent shale stabilizing properties as more concentrated formate brines.

Although there are indications that very low concentration potassium formate brines are more inhibitive than other potassium brines of the same potassium molar concentration [6][7], there might be methods of further improving the shale stabilizing properties of these brines. For example, at a given density one would expect a blend of sodium and potassium formate brine to perform better than the potassium formate single-salt brine at the same density. Such a blend would have a higher filtrate viscosity than the pure potassium formate brine whilst still providing swelling inhibition from the presence of potassium ions. Cabot Specialty Fluids is unaware of any tests to confirm this.

Commonly available shale-stabilizing additives (see B11.6) that are either ineffective or incompatible with concentrated formate brines might be useful in very dilute formate brines. This could be an interesting area of further research.

B11.8 References

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