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Shale Stabilization by High-Salinity Formate Drilling Fluids

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Abstract

High-salinity formate brines are well-known for their application serving as reservoir drilling, completion and perforating fluids in high-pressure high-temperature (HPHT) operations. Less well-known is that these brines also yield unique benefits for drilling shales, which make up 70-80% of all formations drilled. Recent papers have shown that under the right circumstances, high-salinity formate drilling fluids can out-drill oil- and synthetic-based muds when drilling shale.

This paper explores in detail the various mechanisms employed by cesium formate fluids and mixed cesium / potassium formate fluids to stabilize shales and enhance drilling performance in shales, which include:

- Favorable clay "inhibition", i.e. suppression of swelling pressures between clay platelets.
- Enhanced filtrate viscosity, yielding reduced mud pressure penetration in all types of shales.
- Induced osmotic backflow, which can compensate for hydraulic inflow into shales with a "leaky" membrane and thereby offset mud pressure penetration.
- Osmotic dehydration of outer shale layers to minimize bit-balling and accretion tendencies, benefiting ROP.
- Excellent lubricity, which minimizes friction, improves torque and drag, benefits force transmission to the bit, etc.

These mechanisms were investigated in different shale tests including sophisticated pressure transmission tests (PTT) and newly introduced thick-wall cylinder (TWC) collapse tests conducted on both intact and micro-fractured shales. The results confirm the various benefits, ranging from superior inhibition to osmosis, which high-salinity cesium/potassium formate brines bestow on drilling fluids based on them. This makes these fluids excellent candidates to drill shales while addressing the disadvantages of oil and synthetic-based muds used predominantly for this application in current field practice.

Introduction

Oil-based and synthetic based muds (OBM / SBM) are favored by drilling engineers globally for a number of appealing drilling qualities, including shale compatibility, reduced bit-balling tendency in reactive shale formations translating in high rate-of-penetration (ROP), superior fluid loss control properties, excellent lubricity, and favorably high-pressure high-temperature (HPHT) stability. However, as shown in Fig.1, these favorable qualities are often offset by less favorable characteristics such as poor compatibility with cement, fluids being prone to severe lost circulation (because of reduced fracture propagation pressures), oil emulsion blocking in tight gas sands, electrical / resistivity logging difficulties, difficulties detecting gas kicks that go into solution, etc. In addition, the recent large-scale adoption of SBMs for shale drilling has led to issues with waste disposal costs and logistics.

The quest to identify suitable water-based alternatives for OBM / SBM is therefore still as relevant as ever, and high-salinity fluids make compelling replacement candidates. In this paper, we focus on high-salinity monovalent formate brines and side-step divalent brines such as $CaCl_2$, $CaBr_2$, $ZnBr_2$, etc. The latter come with their own set of disadvantages, including high corrosion tendencies, environmental compatibility concerns, occupational hygiene hazards, fluid formulation difficulties, reservoir impairment potential, etc.

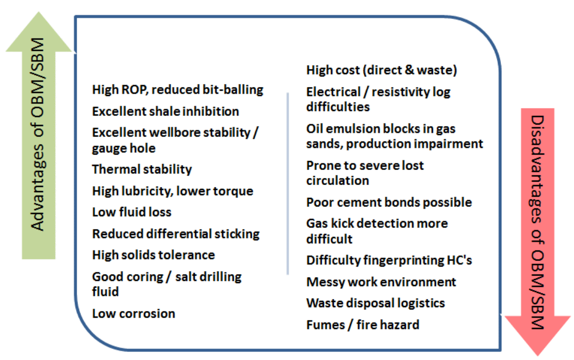


Figure 1 – Advantages and disadvantages of OBM/SBM.

Since their introduction some 25 years ago, high-salinity formate fluids have earned an excellent reputation for competently drilling reservoir formations with no discernable reservoir damage and production impairment problems (see e.g. Downs, 1992, 2006). Likewise, instability of any clay/shale formations present in reservoir intervals appears to be quite rare when drilling with high-salinity formates (while at the same time avoiding the impairment potential of OBM / SBM). As will be explained in this paper, there are very solid reasons for this, reasons which also should make such formate fluids attractive candidates for shale drilling in general, not just HPHT reservoir drilling. The benefits these fluids provide derive from a variety of properties that range from superior clay inhibition to excellent wellbore stabilizing qualities.

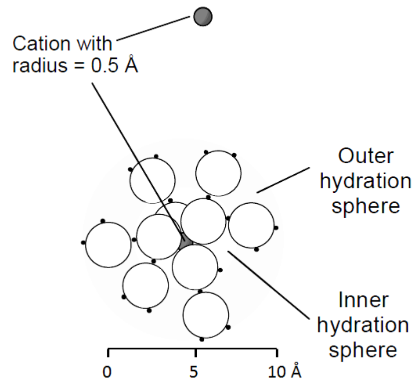
Theory - Swelling Pressure and Inhibition

It is well-known that potassium ions (K^+) are very effective in suppressing swelling tendencies in reactive clays / shales, particularly clays belonging to the smectite family. This "inhibitive" quality of K^+ is the reason why potassium chloride (KCl) - since the introduction of "Shell polymer mud" in the 1970's (Clark et al, 1976) - finds application in KCl polymer muds. These muds have a proven track record in providing good cuttings stability when drilling reactive clays/shales, a quality that unfortunately does not translate into wellbore stability.

Less well-known is that there is one elemental cation that is even more "inhibitive" than the K^+ ion, and it is the cesium ion (Cs^+). The reason for this is as follows. For the well-compacted and consolidated clays and shales that are typically drilled in the field, the clay platelet spacings are usually very small, i.e. on the order of several nanometers to several tens of nanometers. At these small platelets spacings, continuum theories to explain inter-platelet interactions can no longer be used. The well-known DLVO theory, which combines electrostatic (Born) repulsion and van der Waals attraction, breaks down at this point. As demonstrated by the work by Pashley, Israelachvili and others (see Israelachvili, 2011, and references therein), the intermolecular repulsive interactions, or "swelling pressures" in oilfield jargon, are now governed by intricate hydration forces. At solute concentrations above a certain critical value – the critical hydration concentration (CHC), a limit that is usually exceeded in drilling fluid applications – the presence of hydrated ions within the inter-platelet spacings exerts a strong repulsive force.

Extensive studies on mica (Goldberg et al., 2008) have shown that this repulsive hydration force follows the sequence $Cs^+ \leq K^+ < Na^+ < Li^+$. The reason for this is that the Cs^+ ion has the smallest hydrated radius of all the alkali and earth alkali cations, i.e. it carries with it the smallest "shell" of water molecules. This is illustrated in Fig.2a&b. While Cs^+ by itself is one of the larger cations (with a radius of ~1.67Å), its extended electron cloud has a low charge density that limits the ion's ability to structure and bind water molecules to it, resulting in a small hydrated radius (~3.3Å). By comparison, Ca^{2+} is a smaller cation (~1.0Å) but with a high charge density with strong ability to structure water around it, leading to an extended hydrated radius (~4.1Å). Moreover, as shown by Goldberg et al. (2008), the hydration shell around Cs^+ is more easily removed compared to other ions, leading directly to a lower hydration repulsion force. In energy units expressed in k_BT, where k_B is Boltzmann's constant and T is temperature, the energy requirement for removal of hydration shells for alkali metals is as follows: Cs^+ (9–19) k_BT; K^+ (13–27) k_BT; Na^+ (24–41) k_BT; Li+ (34–52) k_BT. The ease by which Cs^+ can shed its water layer allows the ion to exchange effectively with other ions and condensate onto the clay surface, thereby effectively neutralizing its negative surface potential. This also has a favorable effect of effectively reducing the repulsion force between clay platelets (see Fig. 2c). Such condensation is largely prevented for other ions (K^+, Na^+, Li^+, etc.) by their much more strongly held hydration layer.

The inhibitive qualities of Cs^+ and K^+, coupled with their osmotic properties in concentrated formate solutions, usually results in excellent cuttings stability that rivals what is normally observed in OBM/SBM. Inhibition alone, however, is insufficient to guarantee wellbore stability, as discussed in the following.



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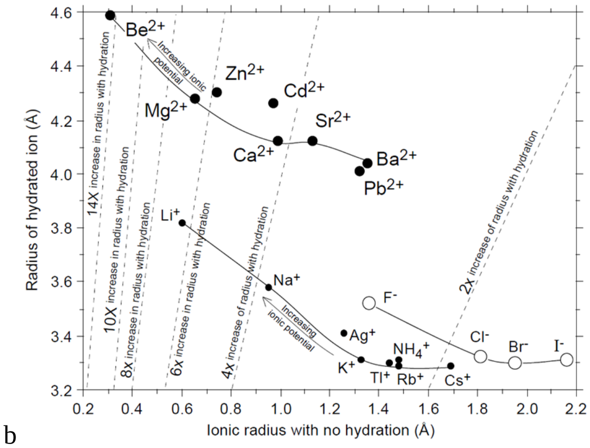

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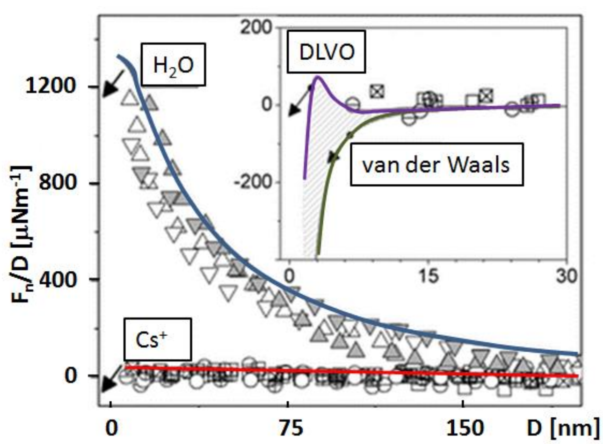


c

Figure 2 – (a) schematic explaining hydrated radius; (b) hydrated ion radius for alkali and earth alkali metal ions (after Railsback, 2016); (c) Normal force vs. distance profiles between curved mica surfaces across salt-free water and 100 mM $CsNO_3$ solutions, as reported by Goldberg et al. (2008).

Theory - Borehole Stability

The requirements for cuttings stability and borehole stability are not the same. A detailed discussion has been given elsewhere (Bol et al., 1994; van Oort, 2003), but the essence as outlined above is that cuttings stability primarily revolves around controlling (the adverse effects of) the swelling pressure. This can be achieved through inhibition, i.e. favorable cation exchange at clay surface sites to lower hydration solvation forces, often aided by the use of certain polymers (e.g. polyamines) with chemically active groups that can bind onto shale surfaces and temporarily prevent them from disintegrating. Borehole stability, on the other hand, revolves primarily around application of the right mud weight (more accurately: maintaining the right dynamic and static downhole pressure) to prevent mechanical failure: if the wrong mud weight / downhole pressure is applied, immediate borehole caving will occur, irrespective of mud type or composition. Once the correct mud weight is established, however, instability over time may still occur if mud pressure can diffuse into the near-wellbore zone and raise near-wellbore pore pressure (Fig.3). This is usually avoided in OBM / SBM due to capillary forces (but may occur in (micro-) fractured shales where such forces are absent) but does occur when WBMs are exposed to low permeability shales at overbalance. The increase in pore pressure over time reduces the near-wellbore effective stresses, driving the stress state toward failure, as shown in Fig. 4.

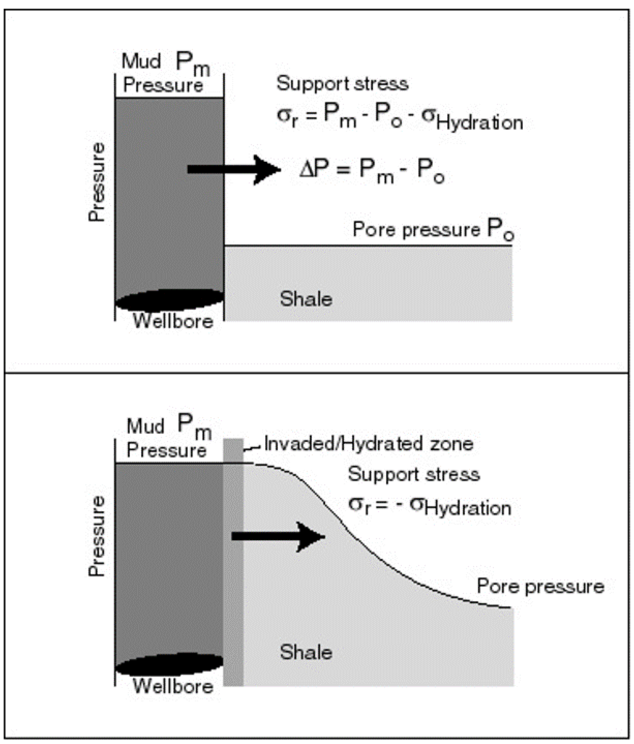


Figure 3 – Pressure transmission in low permeability shales drilled at overbalance with mud pressure P_m raises the near-wellbore pore pressure P_o and reduces the effective pressure overbalance ΔP / radial effective stress σ_r.

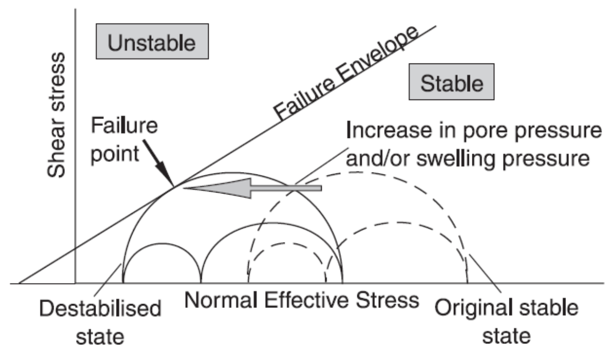


Figure 4 – Mohr-Coulomb representation of shale failure over time. An initially stable stress state with correct mud weight application moves towards the failure envelope when pore pressure or swelling pressure is increased. Mud pressure diffusion in the near-wellbore zone drives the pore pressure increase, which reduces the effective normal stresses (whereas the shear stresses remain unaffected). This shale destabilizing mechanism is not represented by simple (atmospheric) swelling / dispersion tests, and requires more realistic downhole testing including pressure transmission and borehole collapse tests.

Pressure transmission in shales will lead to time-delayed borehole instability, with e.g. borehole enlargement and cavings showing up on shaker screens after several days of open-hole time. An effective way to reduce pressure transmission is to reduce the flux q of drilling fluid filtrate into shales (direction of flow into the shale taken as positive):

$$q = \frac{k}{\mu}(\nabla P - \sigma \nabla \pi) \tag{1}$$

Here, the vector q is the Darcy flux of drilling fluid filtrate [L T^{-1}], k is permeability [L^2], μ is dynamic filtrate viscosity [M $L^{-1}T^{-1}$], ∇P is the fluid pressure gradient vector [$ML^{-2}T^{-2}$], σ is osmotic efficiency [dimensionless], and $\nabla \pi$ is the osmotic pressure gradient vector [$ML^{-2}T^{-2}$]. The latter derives from a chemical potential imbalance between the drilling fluid and the shale. For simple cases, the problem is often rephrased for a given unit distance in terms of a simple hydraulic pressure difference ΔP and osmotic pressure difference $\Delta \pi$ between the drilling fluid filtrate (DF) and the shale pore fluid (SH), with the latter expressed as a difference in water activity a_w:

$$\Delta \pi = -\left(\frac{RT}{V_w}\right) \ln\left(\frac{a_w^{DF}}{a_w^{SH}}\right) \tag{2}$$

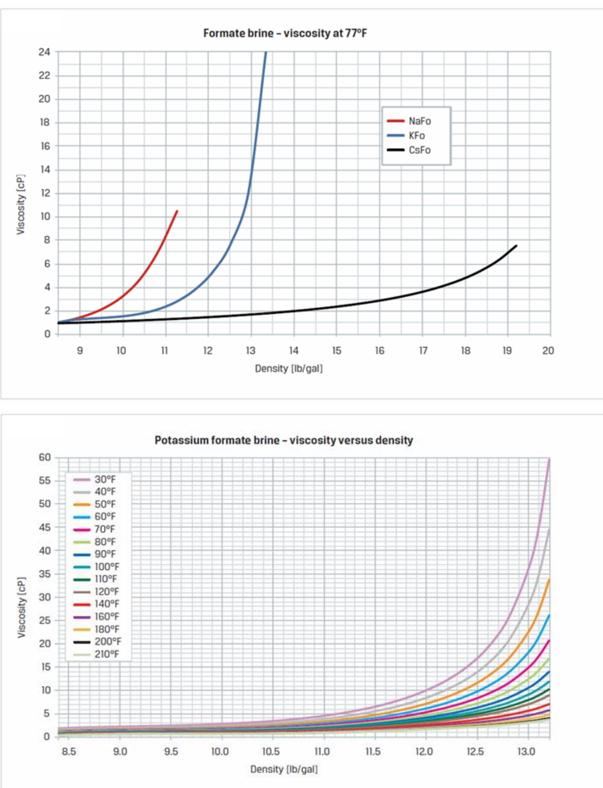
where R is the gas constant [$ML^2T^{-2}\Theta^{-1}mol^{-1}$], T is temperature [Θ], V_w is the molar volume of water [L^3 mol^{-1}], and a_w is the water activity [dimensionless]. The quantity $\Delta \pi$ is the maximum fluid pressure difference that a perfect semi-permeable membrane (i.e., σ = 1) can generate when it separates two fluids with different water activities. As discussed below, shales contacted by high-salinity formate fluids can act as membranes, but their efficiencies are usually not perfect (i.e., σ < 1). This means that the membranes are “leaky”, i.e. they only partially restrict solute/ion transport but do not prevent it completely like a perfect semi-permeable membrane would.

Eq.(1) suggests three comprehensive strategies for reducing mud pressure transmission:

1. Reduce shale permeability k.
2. Increase filter viscosity μ.
3. Counterbalance hydraulic flow into the shale driven by pressure difference ΔP with an effective osmotic back flow form the shale to the mud driven by $\sigma\Delta\pi$.

High-salinity formate fluids do not appear to have any effect, positive or negative, on shale permeability, such that they do not protect shales by strategy (1). However, preliminary evidence (van Oort, 2016; Kaminski et al., 2013) shows that shale plugging agents (such as salt-tolerant silicates, clouding agents) could be added to formate formulations to reduce shale permeability and potentially augment membrane efficiency. This topic, however, is not our primary focus here.

Secondly, the filtrates of concentrated formate muds, which are essentially made up of the high-salinity base brines, exhibit elevated viscosity that can be effectively harnessed to retard and delay pressure transmission. Fig.5 shows formate brine viscosities as a function of fluid density and temperature.



a

b

Figure 5 – (a) Formate brine viscosity at 77ºF as a function of fluid density; (b) potassium formate density as a function of temperature. NaFo = sodium formate, KFo = potassium formate, CsFo = cesium formate. After Howard (2010).

It is seen that brine viscosity increases with salt concentration and fluid density, most prominently for potassium formate. Viscosity reduces with temperature, but always remains elevated compared to water viscosity (which reduces with temperature as well – note that Fig.5 shows absolute viscosities and not relative viscosities compared to water). The increase of viscosity compared to water presents a delay factor that characterizes by how much the dynamics of pressure transmission can be slowed down, and by how much trouble-free open hole time can be increased. For instance, an increase of brine viscosity of a factor 10 compared to water will lengthen trouble-free open hole time by a factor 10 as well. It is, of course, very desirable to achieve a delay factor that is as high as possible, but a recent field study on shale from the Tor/Ekofisk field in the Danish sector of the North Sea (van Oort et al., 2017) showed that a delay factor as low as 2 may already yield significant operational improvement in the field, provided that the lengthened open hole time provides enough time to drill the hole section, run casing and cement it without major instability problems occurring.

Fig. 6 shows the water activity of formate brine solutions as a function of salt concentration / brine density. It is seen that very low water activities (~0.2) can be achieved when formate fluids approach levels of salt saturation in solution. Such low water activities can generate very high theoretical osmotic pressures π (many 1000's of psi). To benefit from such pressures for shale stabilization, two conditions need to be met: (1) fluids have to be used at sufficient salt concentration and fluid density for the osmotic pressure value to be significant; (2) the membrane efficiency σ, which moderates the osmotic pressure, needs to be non-zero.

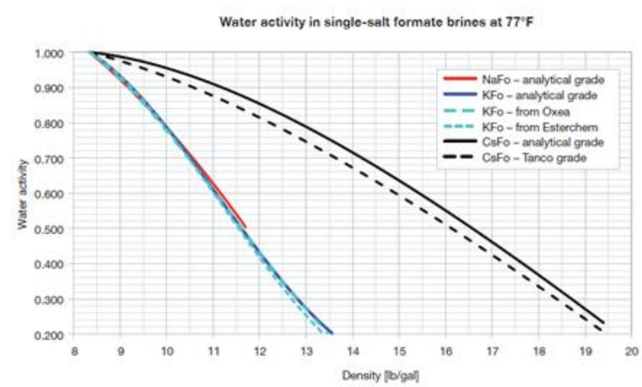


Figure 6 – Water activity of different formate brines from different sources as a function of density. NaFo = sodium formate, KFo = potassium formate CsFo = cesium formate. After Howard (2010).

The condition of a non-zero membrane efficiency requires that the shale acts as a selective filtration medium for the transport of solutes/ions on the one hand, and water on the other. Previous work has shown that under certain conditions shales indeed have such selective filtration properties, although the membrane is rarely perfect and more likely to be leaky, i.e. transport of solutes/ions is restricted compared to water but not completely prohibited. The membrane behavior of refined clays and modified geologic material is well-studied: refined bentonite [Kemper, 1961; Fritz and Marine, 1983; Keijzer, 2000], kaolinite [Olsen, 1969], smectite [Fritz and Whitworth, 1994], Pierre Shale [Kemper, 1961], harbor sludge [Keijzer, 2000], and geosynthetic liner media [Malusis and Shackelford, 2004]. Bresler (1973) formulated a model that explains the experimental results, with the membrane efficiency given as a function of the quantity $bC^{1/2}$, with b [L] being the half width of the pore spaces, and C is salt/ solute concentration expressed as normality. Shales as osmotic "geo-membranes" that can influence subsurface pore pressure distributions through osmosis were studied extensively also by Berry (1969), Kharaka and Berry (1973), Neuzil (2000), Marine and Fritz (1981), Fritz and Marine (1983), Al-Bazali (2005), and Neuzil and Provost (2009). The latter authors summarize prior work and investigate factors that may influence membrane efficiency. Perhaps surprisingly, they fail to find a correlation for membrane efficiency with such factors as reactive clay (smectite) content, cation exchange capacity (CEC), and general clay content. High membrane efficiencies were observed for low-reactivity, low CEC clays and shales, as studied in the work by Noy et al. (2004), Boisson (2005), Al-Bazali (2005), and Rahman at al. (2005). It appears that the main determining formation factor is the size of the pore spaces, with smaller pore sizes yielding higher membrane efficiencies, in agreement with the aforementioned model by Bresler (1973). A fluid factor that affects elective transport is the hydrated size of cations and anions, with larger hydrated sizes leading to more effective exclusion from the pore system.

It is important to note here that membrane efficiency becomes effectively zero if the shale is (micro-)fractured, when all selectivity to solute/ion transport disappears (note that this is also in agreement with Bresler's model, with (micro-)fractures representing pore spaces with large value for half width variable b). Micro-fractures may be present in-situ, but may also be artificially induced during shale coring and stress relief during uplift of the core to surface. This should always be a consideration during experimentation. When a core sample exhibits micro-fractures, all osmotic effects will disappear in pressure transmission and other rock mechanical tests, leaving only the aforementioned viscosity effects. If the micro-fractures were artificially induced, then the absence of osmotic effects is a sample preparation and test artifact.

Fig.7 shows schematically the behavior of osmotic flow in a shale with a non-zero membrane efficiency, using a cesium formate (CsCOOH) fluid as an example. When the shale is contacted by a concentrated, low water-activity cesium formate solution, there is an evident chemical potential imbalance with the shale pore fluid, which will be at a higher activity. This imbalance can be negated by transport of hydrated ions (Cs^+, $COOH^-$ - note that both ions need to be considered to guarantee electro-neutrality in solution) into the shale and transport of water out of the shale. If the shale has selectivity to transport, then the water transport out of the shale occurs at a faster rate than the transport of ions into the shale, leading to a net mass transport from the shale to the formate fluid. By itself, this transport will tend to lower the near-wellbore pore pressure, and this effect can be used to (partially) offset the hydraulic influx of filtrate into the shale and the associated increase in pore pressure.

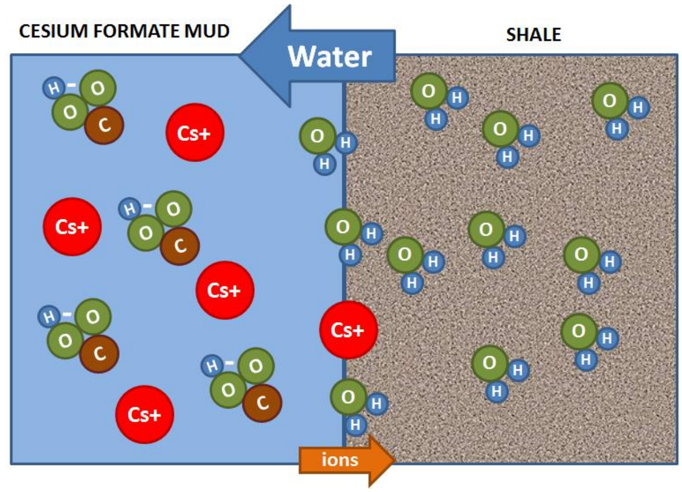


Figure 7 – Schematic of selective transport across a "leaky" membrane when the shale is contacted by a high salinity, low water-activity cesium formate fluid.

There are now 4 different scenario's to consider:

1. $\sigma\Delta\pi = 0$; this situation occurs when the shale is (micro-)fractured, or simply has large pore spaces that do not support selective transport. In this case, Eq.1 reduces to:

$$q = \frac{k}{\mu}\Delta p \tag{3}$$

   and the only pressure retardation effects observed in pressure transmission tests are due to enhanced viscosity.

2. $\sigma\Delta\pi > 0$, $\sigma\Delta\pi < \Delta P$, $q > 0$; in this case, the effective osmotic pressure is insufficient to completely counterbalance the hydraulic overbalance, but partial compensation still happens. This can translate in a significant increase in the delay factor (and associated increase in trouble-free open hole time) observed in pressure transmission tests that goes beyond the effect of viscosity.

3. $\sigma\Delta\pi > 0$, $\sigma\Delta\pi = \Delta P$, $q = 0$; in this case, the effective osmotic pressure balances the hydraulic overbalance, and no pressure transmission will occur (at least not initially – note that the membrane is leaky, such that solute/ion invasion into the shale will occur, which will eventually destroy the chemical potential imbalance that generates the effective osmotic pressure $\sigma\Delta\pi$; however, this could take a very long time).

4. $\sigma\Delta\pi > 0$, $\sigma\Delta\pi > \Delta P$, $q < 0$; in this case, the effective osmotic pressure exceeds the hydraulic overbalance, and net fluid mass transport from the shale to the drilling fluid will occur. This will have the effect of lowering the near-wellbore pore pressure and increasing the effective stresses, which will result in a more stable wellbore. In pressure transmission tests, a drop in pore pressure and downstream reservoir pressure will be observed despite the hydraulic overbalance that is applied to the shale sample. The concerns about catastrophic dehydration, or "desiccation", of the shale are addressed at the end of this paper.

It is noted that high-salinity formate fluid can, to a different extent, benefit wellbore stability in all of these 4 scenarios.

Experimental

Three types of shale materials were used for this study: Mancos shale, a Late Cretaceous shale of low reactivity (i.e. low reactive clay content) and a permeability of <10 nD, a North Sea Miocene shale with a high clay content (60-70%), a high CEC (50 – 70 meq/100g) and a permeability of ~3 nD, and a Pliocene Middle East shale of low reactivity with a permeability of ~0.3 nD. Formate tests were conducted on the North Sea Miocene shale in direct comparison with other mud systems, including commercial WBMs, high-performance WBMs (HP-WBM) and OBM formulations at 13.5 ppg density (for details, see van Oort et al., 2017). A full suite of tests, as recommended for shale-fluid compatibility testing by van Oort et al. (2016), was conducted on the North Sea shale, including accretion, cuttings disintegration, pressure transmission and thick walled cylinder collapse tests. Pressure transmission tests were also run for the Mancos shale and Middle East shale.

The test procedures and conditions for pressure transmission and thick walled cylinder tests are given in the Appendix. Procedures for accretions and cuttings dispersion tests are given elsewhere (Hale, 1991; van Oort et al., 2015). Data processing for the pressure transmission tests was as follows. Downstream pressure build-up behavior is measured in the test as a result of an applied upstream hydraulic pressure overbalance. The pressure diffusion behavior through the shale sample is similar to the charging of a capacitor in a RC circuit, and is given by (van Oort, 1994):

$$\frac{P(l,t)-P_o}{P_m-P_o} = 1 - \exp\left[-\frac{Akt}{\mu\beta V l}\right] \quad (4)$$

where

P_o = *initial pore pressure (Pa),*
P_m = *upstream fluid pressure (Pa),*
$P(l,t)$ = *downstream pressure at sample end (Pa)*
l = *sample length (m)*
A = *sample cross-sectional area* (m^2)
V = *volume of downstream reservoir* (m^3)
β = *fluid compressibility* (Pa^{-1})
μ = *fluid viscosity (Pa.s)*
k = *relative shale permeability* (m^2)

Tests are typically performed with two distinct cycles: a first cycle using artificial shale pore fluid, to characterize rock permeability, and a second cycle (after re-equilibrating the rock sample to initial conditions) with test fluid. Since the viscosity μ and compressibility β of the filtrate of the test mud are generally unknown, a hydraulic conductivity $k/\mu\beta$ (m^2/s) is characterized for each pore fluid cycle and subsequent test fluid cycle. These are compared to yield a "delay factor" given by:

$$Delay\ Factor = \frac{Hydraulic\ Conductivity\ (Test\ Mud)}{Hydraulic\ Conductivity\ (Pore\ Fluid)} \quad (5)$$

The delay factor shows the delay in the rate of pore pressure elevation that is expected for a particular fluid system. This delay factor is directly related to trouble-free open hole time, as it indicates by how much the dynamics of the shale destabilizing pressure invasion can be slowed down.

Results and Discussion

Accretion and Cuttings Disintegration Tests

Figure 8 shows the accretion test results of 13.5 ppg mixed cesium / potassium formate mud on North Sea Miocene shale. Clearly, the amount of shale retained on steel is minimal. In comparative testing with other mud systems, this result was one of the best obtained and was only bested by a modified OBM formulation (but it outperformed a regular OBM system). It should be noted that the accretion results obtained with Miocene shale were low, and that none of these mud systems showed concerning levels of shale accretion. The results highlight the extra-ordinary anti-accretion characteristics of high-salinity formate systems, which translate in a low bit-balling tendency and high rate-of-penetration (ROP) in shales (van Oort et al., 2015), as well as low friction coefficients.

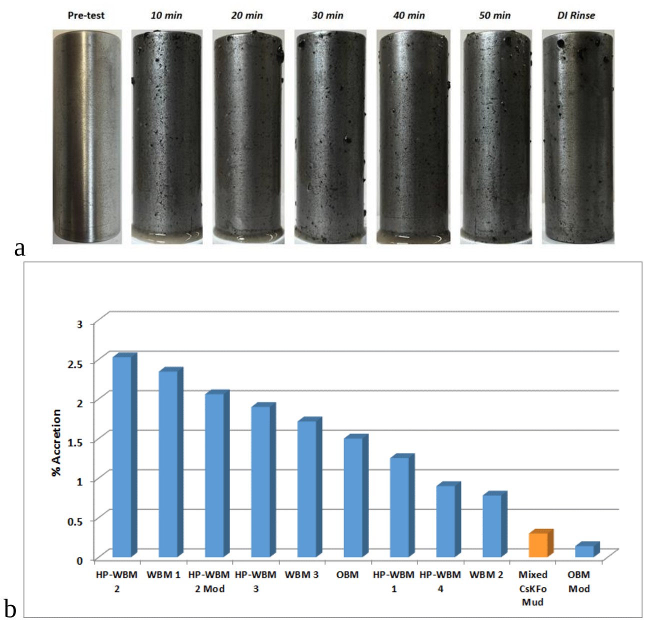


Figure 8 – (a) Accretion result for mixed CsKFo mud, showing steel rolling bars with (negligible) accreted material at various time intervals; (b) Accretion results for CsKFo (in orange), compared to other mud systems. Accretion levels for all muds are generally very low (< 3%), but are particularly good for mixed CsKFo mud.

Figure 9 shows cuttings disintegration results for 13.5 ppg mixed cesium / potassium formate mud on North Sea Miocene shale. Despite its high clay content, the shale did not readily disintegrate, as indicated by relatively high cuttings recovery factors (~68%) in tapwater. The maximum recovery recorded in the test was around 85-86%, a result achieved with mixed cesium / potassium formate mud, on par with modified OBM and some commercial HP-WBM systems. Note that the fact that maximum recovery was not at 100% was due to mechanical erosion of cuttings during the hot-rolling tests, which also gets recorded as "dispersion". The cuttings obtained after testing in formate mud appeared basically unaltered, in agreement with the information given earlier on the ability of these muds to stabilize shale cuttings.

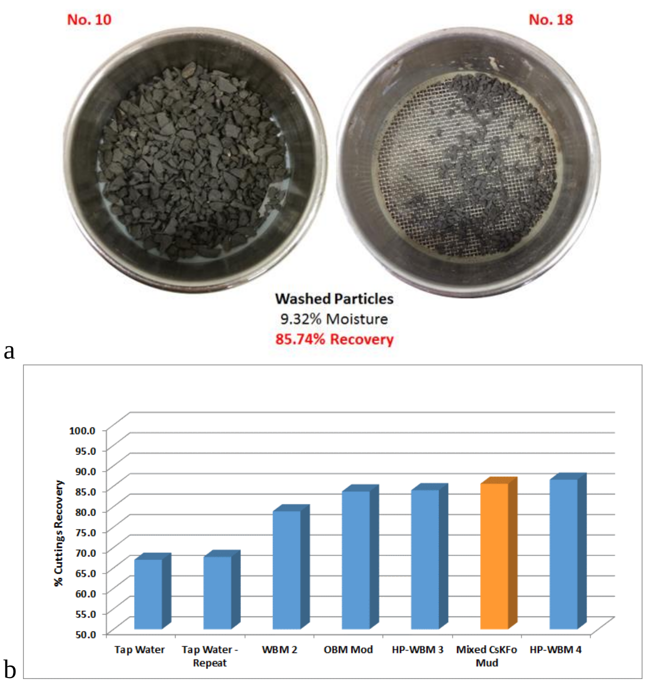


Figure 9 – (a) Cuttings dispersion result for mixed CsKFo mud after testing, showing cuttings recoveries on No.10 and No.18 API screens at the end of the test for an overall recovery of 85.7%. Cuttings basically appeared to be unaltered after testing; (b) cuttings dispersion results for CsKFo mud (in orange) compared to other muds and tapwater.

Pressure Transmission Tests

Fig.10 reproduces a result by van Oort (1994) on testing a saturated 76% w/w, 13.6 ppg (1.63 SG) potassium formate fluid on unconfined Pierre shale, which contains open micro-fractures (which can be closed when tests are done under confinement). A pressure transmission delay factor of ~20 was obtained, in agreement with the filtrate viscosity of 17.4 cP of the formate fluid. It is an example of pressure transmission delay caused solely by enhanced filtrate viscosity reflective of Scenario 1 in the "Theory – Borehole Stability" section.

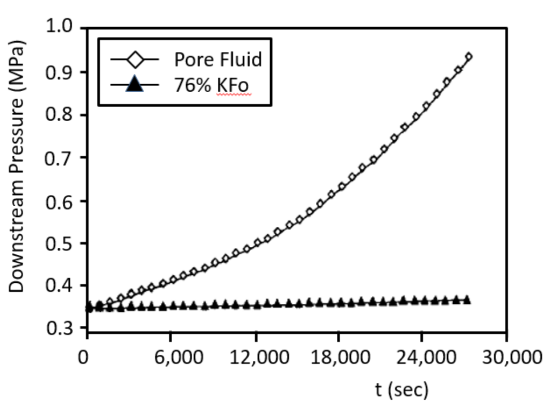


Figure 10 – Pressure transmission test result for a 13.6 ppg (1.63 SG) potassium formate fluid (KFo) on Pierre shale (adopted from van Oort, 1994).

Fig.11 shows the pressure transmission result of 15.3 ppg (1.84 SG) mixed cesium potassium formate mud on Mancos shale at 1000 psi confining pressure and 95ºF temperature. A sizeable delay factor of ~12 was observed. This result is in line with expectations based on enhanced filtrate viscosity in the absence of any osmotic effects, similar to the saturated potassium formate result shown in Fig. 10 and best described by Scenario 1 in the "Theory – Borehole Stability" section.

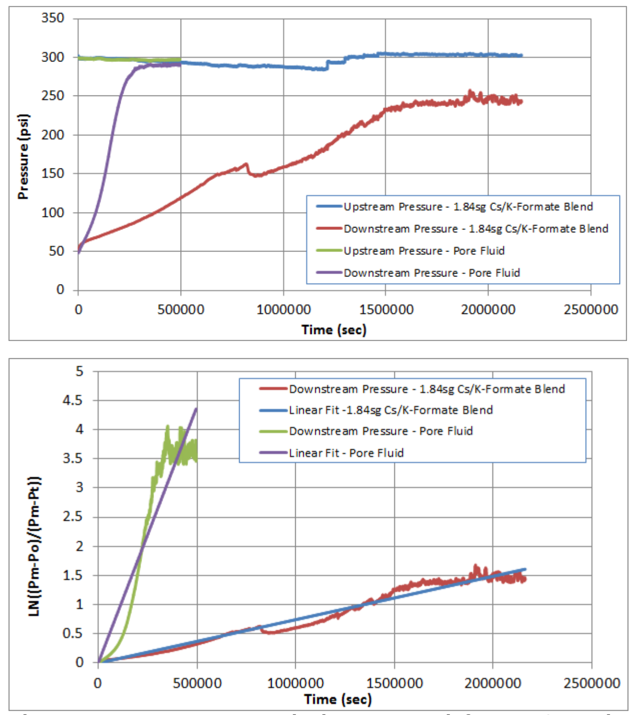


Figure 11 – Pressure transmission test result for a 15.3 ppg (1.84 SG) mixed cesium potassium formate fluid on Mancos shale.

Fig.12 shows the pressure transmission result of 18.3 ppg (2.2 SG) cesium formate mud on Mancos shale confined at 1000 psi and 95ºF temperature. A large delay factor of ~55 with very slow pressure fluid-up for the formate fluid was observed. This result goes beyond what is expected for a delay factor based on viscosity alone, as the highest viscosity for a cesium formate fluid is around 7 - 8 cP (see Fig.5a). Clearly, there is an additional osmotic effect acting to balance the hydraulic pressure, in a way reflective of Scenario's 2 & 3 in the "Theory – Borehole Stability" section.

The reason why an osmotic effects was not observed for the mixed cesium potassium formate fluid (Fig. 11) whereas it was observed for the pure cesium formate fluid (Fig. 12) has less to do with the fluids themselves (their water activities are very similar, and so are the osmotic pressures that they generate) and more with the variability of the Mancos material properties itself. Mancos shale is highly variable rock material with strong variation in its mineralogy, porosity, permeability, etc. Potential damage (micro-fractures) and variation in damage to individual core samples also has to be taken into consideration. This variability explains why osmotic effects may be strong in one set of tests, and may be completely absent in another.

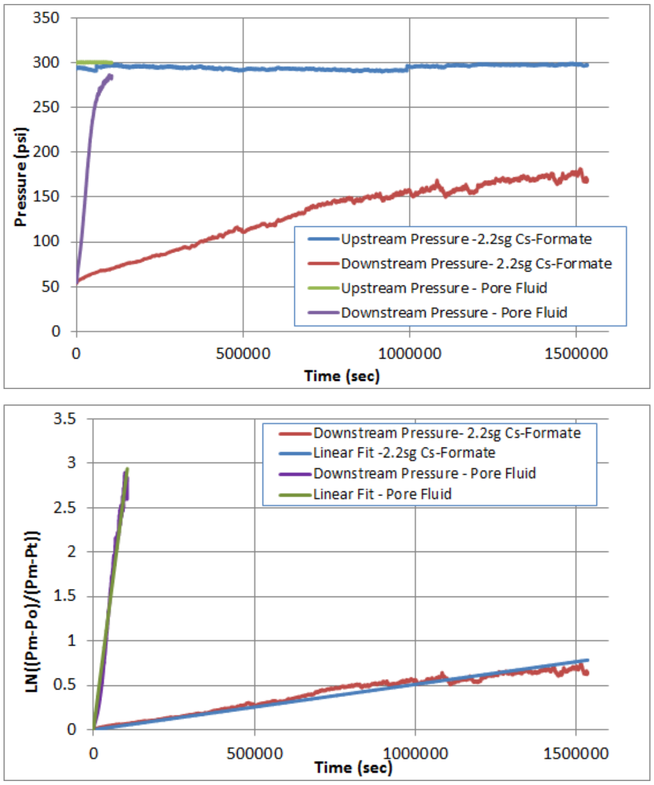


Figure 12 – Pressure transmission test result for an 18.3 ppg (2.24 SG) cesium formate fluid on Mancos shale.

The PTT results for a 13.5 ppg (1.62 SG) mixed cesium potassium formate mud tested on North Sea Miocene shale are shown in Fig. 13, indicating a delay factor of 12.5. This delay factor is sufficiently explained by viscosity alone, i.e. Scenario 1 in the “Theory – Borehole Stability” section. The absence of any osmotic effects was expected for this shale, since it also allowed for rapid pressure transmission in OBM formulations, a phenomenon not often observed in low-permeability shales. The latter observation indicates that there are no significant capillary pressures at play when OBM contacts this water-wet shale, which means that pore size diameter must be large even when shale permeability is low (at ~3 nD). As discussed previously, large-sized pores do not support selective osmotic transport, in accordance with the model by Bresler (1973).

Despite the absence of osmosis, the result obtained for mixed cesium potassium formate mud was by far the best recorded for the comparative mud testing dataset. This is illustrated in Fig.14, showing the delay factors obtained for the different mud systems. The best delay factor that was obtained had a value of ~2 before the formate system was tested. The latter turned out to be in a class of its own. Note that one of the HP-WBM systems was applied in the field as an alternative to conventional WBM and OBM systems, and yielded significant operational benefits by lengthening trouble-free open hole time (see van Oort at al., 2017). Even better results would be expected for the formate system.

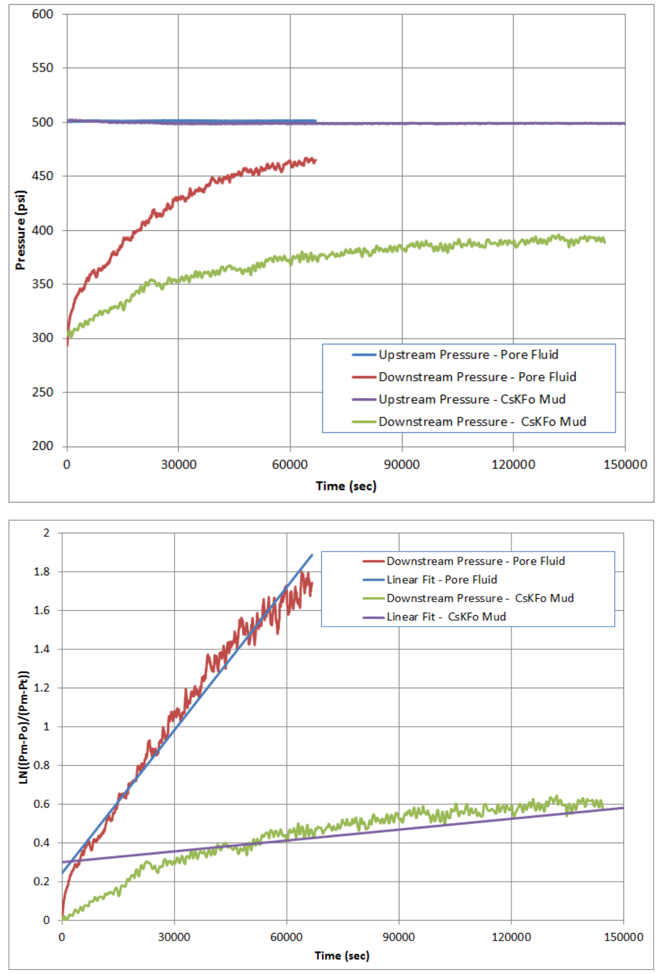


Figure 13 – Pressure transmission test result for a 13.5 ppg (1.62 SG) mixed cesium potassium formate fluid on North Sea Miocene shale.

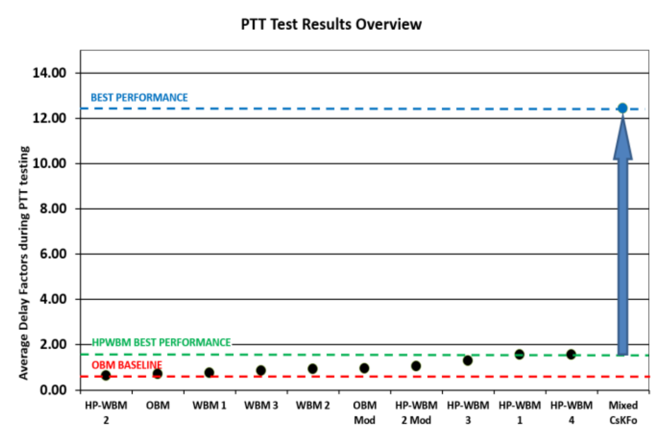
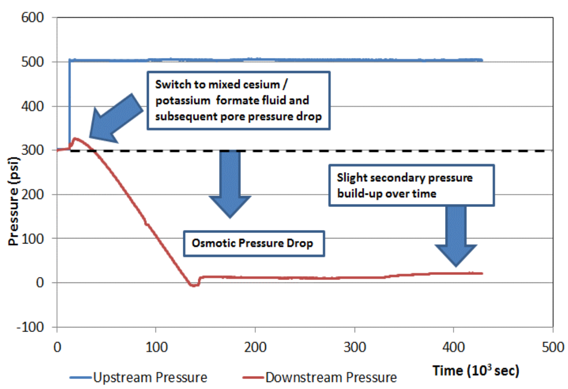
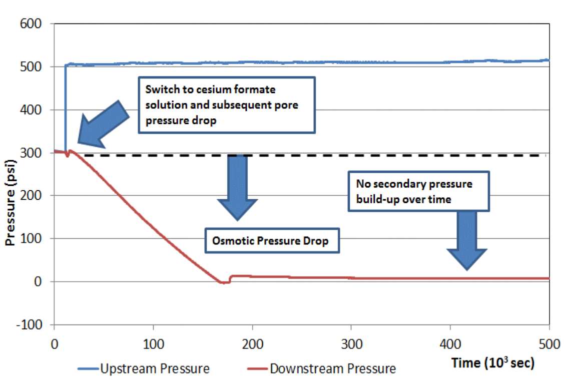


Figure 14 – Overview of absolute delay factors recorded during PTT tests for various mud systems tested, indicating baseline performance by OBM and previous best HPWBM performance by HP-WBM 1 and HP-WBM 4. The blue arrow indicates the step-change improvement observed with CsKFo mud, which is clearly distinguished from the other results.

The PTT results of applying 15 ppg (1.8 SG) mixed cesium potassium formate mud and diluted cesium formate mud on Middle East Pliocene shale are shown in Fig. 15. Note that these formulations are very close to the ones used for Mancos shale tests shown in Figs. 11 & 12. The Pliocene shale has a very low permeability of only ~0.3 nD. For both muds it was observed that downstream pressure dropped almost to zero despite a 200 psi overbalance (300 psi initial pore pressure with upstream pressure raised to 500 psi at the start of the test) after the shale was exposed to the high-salinity formate fluids. The strong osmotic effect, clearly Scenario 4 as described in the "Theory – Borehole Stability" section, was able to overcome a total of 500 psi of upstream pressure. This observation allows us to estimate the membrane efficiency of the shale. At 15 ppg / 1.8 SG, the water activity of diluted cesium formate brine is ~0.6. When tested at a temperature of 95ºF, the theoretical osmotic pressure $\Delta\pi$ acting on the shale is ~10,500 psi. Given the total compensation of 500 psi of pressure, the membrane efficiency is estimate to be $\sigma = 500/10{,}500 = 4.7\%$. This value is in general agreement with values reported for osmotic shales in literature (see Neuzil and Provost, 2009, van Oort et al., 1995, 1996).



a



b

Figure 15 – Results of PTT tests with Middle East Pliocene shale for (a) a 15 ppb (1.8 SG) mixed cesium potassium formate fluid; (b) a 15 ppg (1.8 SG) pure cesium formate fluid. Note that both fluids, which have similar water activities, are able to completely counterbalance the upstream pressure of 500 psi, reducing the downstream pressure to near-zero. The slow secondary pressure build-up in (a) is attributed to salt diffusion in the test, which will eventually remove the chemical potential imbalance.

Thick Walled Cylinder Tests

A series of TWC tests was conducted on the North Sea Miocene shale, including a test on the 13.5 ppg (1.62 SG) mixed cesium potassium formate mud. The outcome of the test result is shown in Fig.16. The sample failed at an average collapse pressure of 2139 psi, which was the highest recorded for the comparative test set (see Fig 17). In fact, within the accuracy of the test, this result fell within the range of uncertainty of the native strength of the shale material. Apparently, the application of the formate mud had no discernable negative effect on the stability of the Miocene shale. Note that no additional formation strengthening effects were expected in the absence of any osmotic effects (that might have dehydrated the shale and increased near-wellbore effective stress) in this shale.

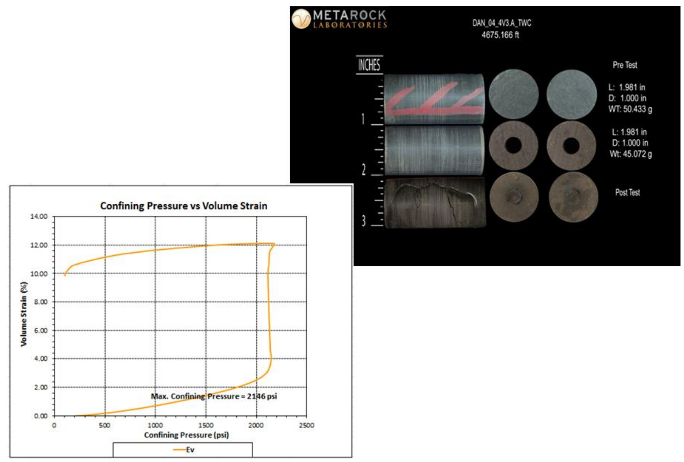


Figure 16 – Photographs of TWC shale samples tested before borehole coring, after coring, and after failure, as well as confining pressure vs. volumetric strain plot for a mixed CsKFo TWC test. A sudden increase in volumetric strain indicates wellbore collapse for this sample at 2,146 psi.

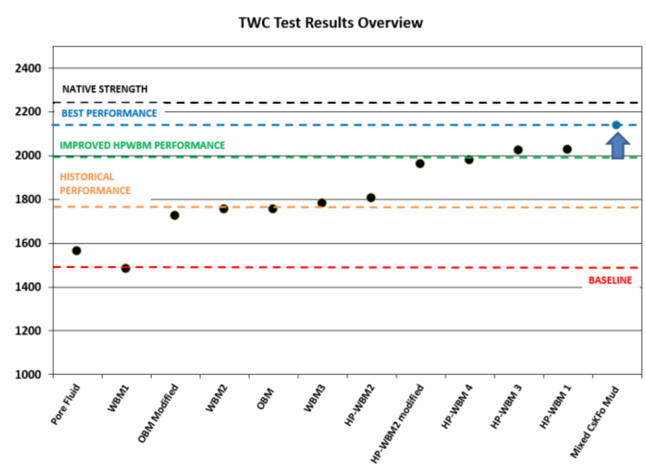


Figure 17 – Overview of average confining pressure (dots) and range (lines) at failure for the various mud systems tested. Note that "Baseline Performance" for pore fluid and WBM 1 mud occurs at ~1,500 psi, "Historical Performance" for OBM (+ modification), WBM 2, WBM 3 and HP-WBM 2 occurs at~1,750 psi, "Improved HPWBM Performance" occurs at ~2,000 psi, "Best Performance" with CsKFo mud occurs at ~ 2,150 psi, with native strength at ~2,250 psi with a variation of ~240 psi. Average result for the CsKFo mud is shown in blue.

The PTT and TWC results for 13.5 ppg (1.62 SG) mixed cesium potassium formate mud tested on North Sea Miocene shale show a great deal of consistency: the large delay factor observed in the PTT tests corresponds with the best observed shale collapse behavior. Fig. 18 shows a crossplot of the TWC collapse pressure vs. the average delay factor observed in the PTT test. The dataset is fitted to an exponential rise function. It is clear that the mixed cesium potassium formate mud stands by itself and presents a step-change in borehole stabilizing performance compared to the other mud systems tested.

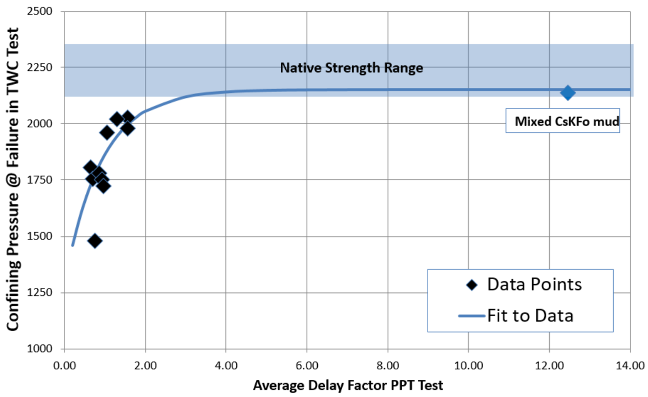


Figure 18 – Confining pressure values of test muds at failure recorded during the TWC tests vs. average delay factor numbers recorded during the PTT tests. Blue diamond indicates the result for the CsKFo formulation, which is in line with the overall trend and shows the best result recorded. Data fit is an exponential rise to a limit: TWC = 1290 + 861(1-e-1.095*PTT) using Excel Solver. (note that one mud exhibits clear outlier behavior, showing PTT behavior similar to OBM but lower TWC collapse pressure; this is attributed to chemical destabilization of the shale caused by this particular WBM system).

Field Experience

High-salinity, high density formate fluids have now been applied for over 20 years in a variety of HPHT drilling, completion and perforating fluid applications in hole intervals with exposed shale formations. In that time, there have been no reports where any shale instability could be positively ascribed to any physio-chemical incompatibility of the formate fluids with the shales. On the contrary, there are numerous reports of very positive experiences that confirm that the positive results described here translate to actual field applications. Overviews of field experiences have been given by Howard (2010) and van Oort et al. (2015). Particularly relevant have been the experiences in a total of ten wells drilled to date in the Kvitebjørn field, where high-angle reservoir sections containing long sections of shales (50% shale, 50% sand) were drilled. No hole enlargement was reported for any of the intersected shale formations, with the formate fluid exposed to organic-rich shales from the Viking group, heterogenic shales from the Brent group, and deep marine shales of the Drake group. Acoustic calipers while drilling and mechanical calipers from wireline logging after drilling indicate only very slight differences in average hole size. Boreholes are mostly gauge, despite the hole having been open and exposed to the formate fluids for several weeks.

Additional Considerations

When mentioning high-salinity formate fluid for shale drilling applications, a concern with catastrophic dehydration or "desiccation" of the shale is sometimes expressed. This concern is often motivated by the outcome of small-scale lab tests, where shale samples are exposed to high-salinity formate fluids and desiccation cracking is observed. This concern is unfounded, as it is due to an artifact in such shale exposure tests. In a small-scale test, there is generally no replenishment of any pore fluid lost to the high-salinity formate fluid by osmosis, as shown in Fig.19. The formate fluid can thereby literally "dry out" the shale sample and have it fall apart. However, this bears no resemblance to the field situation, where a borehole is drilled in a semi-infinite rock medium. Any pore fluid lost at the borehole wall will trigger influx of pore fluid from the far field, as shown in Fig 19. Eventually, a dynamic equilibrium will be established with a stable near-wellbore pore pressure with a lower – but stable – value compared to the in-situ value.

This is exactly what was observed in large-scale Downhole Simulation Cell (DSC) testing (Simpson et al., 1989) reported by van Oort (1996).The DSC test provides the most realistic lab representation of the actual shale behavior in the field. The observed trend in pore pressure during the DSC tests on Eocene shale is reproduced in Fig. 20 for 4 muds, including OBM (with 25% w/w $CaCl_2$ invert emulsion brine) and a saturated potassium formate fluid. A comparable drop in pore pressure was observed for both the OBM and the formate fluid, which stabilized over time, indicative of the aforementioned dynamic equilibrium. Note that shale problems in the field attributed to desiccation cracking by formates have never been reported.

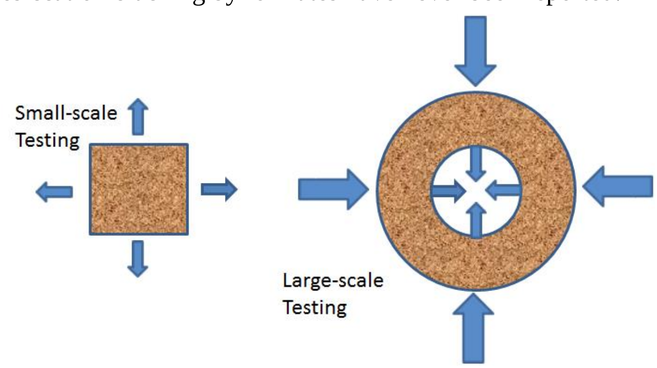


Figure 19 – Difference in shale behavior for small (left) and large-scale (right) tests (such as the DSC test). In small scale test, samples can become completely dehydrated through osmosis when exposed to concentrated formate brines, which is a test artifact. In large-scale tests, as well as in the actual field geometry, near wellbore dehydration will trigger far field pore fluid influx, resulting in a dynamic pore pressure equilibrium.

It is important to note here that good drilling and mud management practices are still required when applying high-salinity formate fluids in the field. Formates are not a panacea and cannot substitute for essential requirements for wellbore stability such as appropriate mud weight selection and appropriate downhole pressure management (e.g. control over swab and surge pressures and other dynamic annular pressure fluctuations that may cause induced wellbore failure).

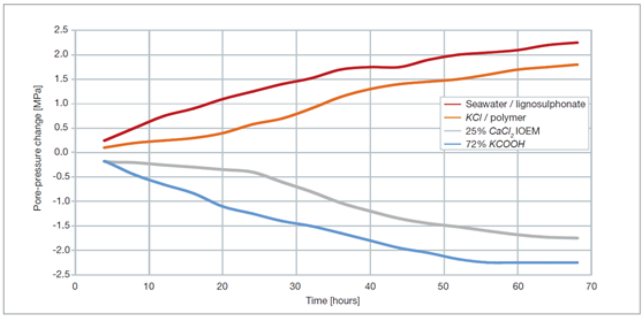


Figure 20 – DSC test result for 4 mud types. Note the similar pore pressure drop for 72% potassium formate (KCOOH, blue line) and OBM/IOEM (grey line), which stabilizes over time indicative of a dynamic equilibrium. Catastrophic desiccation of the shale by either the OBM or the formate fluid was not observed.

Conclusions

This paper offers an experimental investigation into the shale stabilizing qualities of high-salinity formate fluids, particularly those formulated with cesium and potassium formate. The laboratory tests comprise accretion tests, cuttings dispersion tests, pressure transmission tests and thick wall cylinder tests. The results show that concentrated formate fluids have excellent shale drilling qualities that derive from:

- Favorable clay "inhibition", i.e. suppression of swelling pressures between clay platelets.
- Enhanced filtrate viscosity, yielding reduced mud pressure penetration in all types of shales.
- Induced osmotic backflow, which can compensate for hydraulic inflow into shales with a "leaky" membrane and thereby offset mud pressure penetration.
- Osmotic dehydration of outer shale layers to minimize bit-balling and accretion tendencies, benefiting ROP (discussed previously, see van Oort et al., 2015).
- Excellent accretion behavior and lubricity, which minimizes friction, improves torque and drag, benefits force transmission to the bit, etc.

A clarification is given of the 4 scenario's that may be presented by shales in the field, depending on differences in the magnitude of osmotic phenomena supported by these shales. It is shown through illustrative experimental results that high-salinity formates yield tangible shale stabilizing benefits in each of these 4 scenarios. This, coupled with the fact that formate fluids address many of the downsides of OBM / SBM, makes these fluids superior candidates for shale drilling applications.

Acknowledgments

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Nomenclature

CEC	= *Cation Exchange Capacity*
CsFo	= *Cesium Formate*
CsKFo	= *Mixed Cesium Potassium Formate*
DSC	= *Downhole Simulation Cell*
HPWBM	= *High Performance Water-Based Mud*
IOEM	= *Invert Oil Emulsion Mud (i.e. OBM)*
KFo	= *Potassium Formate*
NaFo	= *Sodium Formate*
OBM	= *Oil Based Mud*
PTT	= *Pressure Transmission Test*
ROP	= *Rate of Penetration*
SBM	= *Synthetic Based Mud*
WBM	= *Water Based Mud*

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Appendix

Pressure Transmission Test

- Use was made of specially constructed pressure transmission test (PTT) equipment at Metarock, based on original designs by van Oort, 1994. For additional information, the reader is referred to this paper.
- Representative cylindrical shale sample, 1" in diameter and 1" in length were cored from the Dany-1X shale core. All PTT tests were run in duplicate.
- Test preparation involved mounting a sample in a Hassler-type cell between two fluid ends, which accommodated exposure of the shale sample to fluid (pore fluid or drilling mud at the upstream face, pore fluid at the downstream face). Moreover, the sample was confined with a radial sleeve.
- The sample was placed under a radial confining pressure of 1000 psi, and exposed to artificial pore fluid (usually artificial seawater, ~3.5% NaCl solution) on both sides of the core (i.e. both in the upstream and downstream reservoir) at a pressure of 300 psi and temperature of 35 ºC (95 ºF). Note that some tests used a pore pressure of 50 psi.
- The start of the first test cycle, which served the purposes of characterizing the permeability and hydraulic conductivity of the shale sample, was initiated by raising the pressure of the pore fluid in the upstream reservoir to 500 psi (i.e. 200 psi overbalance) and monitoring the pressure build-up due to pressure diffusion through the sample on the closed-in downstream reservoir using appropriate pressure transducers. Note that some tests used an upstream pressure of 300 psi and 50 psi initial pore pressure, i.e. a 250 psi overbalance.
- As soon as sufficient downstream pressure build-up was observed (typically a minimum of 75% of the initial overbalance), the first test cycle was finalized and both upstream and downstream pressures were reduced back to 300 psi (or 50 psi) and the shale sample was re-equilibrated to this pore pressure value.
- At the start of the second test cycle, pore fluid was displaced under pressure from the upstream side and replaced by the test fluid. A sufficient volume of mud was flushed past the face of the core to ensure that all pore fluid was properly displaced. Upstream pressure was once again raised to 500 psi (or 300 psi) and downstream pressure was monitored.
- Once sufficient downstream pressure build-up was observed (typically a minimum of 75% of the initial overbalance), the second test cycle was completed and the system was de-pressurized and disassembled.
- Processing of the pressure data is done in accordance with the procedure given in the main text.

Modified TWC Test

- A sample of 1" in diameter, 2" in length (i.e. length-to-diameter ratio of 2) is cut from representative, well-preserved shale material that does not show noticeable cracks. A 0.3" centralized borehole is drilled along the entire length of the sample.
- The sample is photographed in axial and radial directions before and after the borehole is drilled, prior to testing. Care should be taken not to allow the sample to dry out during this phase.
- A Viton sleeve is measured to the size of the particular sample, and fitted around it. An endcap is placed at the bottom of the sample. Utilizing a heat gun, the bottom of the sleeve is heated around the endcap.
- A cantilever bridge is placed around the sample. Additionally, a band and curved brass spacers are placed around it to help hold it in place. This will also assist in measuring the radial strain of the sample.
- The top endcap is placed on the sample. This also aids in ensuring the sleeve will hold in place and everything will attach more effectively. Internal LVDT's measuring axial strain are attached to the end caps.
- The top of the sleeve is heated up around the sample. The sample is then ready to be loaded into the triaxial test cell. Fluid lines (for pore/confining pressure) and measurement channels are connected and brought online as necessary.
- The sample is saturated at a pore pressure value (typically 50-200 psi) with synthetic pore fluid in the borehole for a period of 3-4 hours. The synthetic pore fluid is based on water analysis from pore water e.g. obtained during a prior shale squeeze test. This saturation step is essential to ensure that samples are fully saturated when tested with test fluid: (partial) dehydration of the sample would lead to significant test artifacts. Once stabilization occurs the pore pressure is dropped to 0 psi and the brine is flushed from the borehole.
- The borehole is now displaced to a drilling fluid test formulation and borehole pressure is held constant at overbalance (typically 200 psi) for a period in the range of 12-24 hours (note that longer time periods can be applied, as necessary/desirable).
- After 12-24 hours, confining stress around the sample is increased at 1 μstrain/sec until the point of failure. Expelled volume and strains are monitored throughout the test. A sudden increase in volumetric strain indicates borehole failure. The confining pressure at failure is reported as shale borehole strength upon fluid exposure.
- The sample is then unloaded and the sleeve is removed. It is subsequently photographed in axial and radial directions to document the sample failure mode. The failed sample is safely stored in a storage unit for tested samples where an accurate inventory is kept. This allows for any further post-mortem inspection, if necessary.