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Laboratory Study of Fracture Development in the Anadarko Basin Shale, Texas, Using Drilling Fluids for Coiled-Tubing Operations

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Abstract

Understanding and identifying the mechanics surrounding the interactions between shale and fluids, and their effect on wellbore integrity, can help to conquer the challenge of drilling troublesome shale formations.

Shale stability studies using core samples are among best methods to investigate and evaluate the effects of fluids in shales. Studies that encompass petrographic description and characterization of the core samples along with rock-fluid interaction tests offer an better approach to the understanding of the response of shales in different fluid environments and the relationship of different behaviors with rock characteristics.

In a recent pilot program to test the viability of re-entry in the Anadarko Basin, Texas, coiled-tubing drilling operations experienced severe wellbore instability and fluid-loss problems in the highly deviated shale section directly above the target depleted tight-gas sand reservoir. This paper presents the characterization of a core sample taken from this area and the application of a specific laboratory technique for use in fracture development testing to evaluate the effects of water-based and oil-based drilling fluids on the stability of shale formations. This technique focuses on the study of fracture propagation and weakness of bedding planes in low–medium reactive shales exposed to drilling fluids designed for coiled-tubing applications.

These tests demonstrate how the selection of base fluids and inhibitor additives is important to minimize the propagation of fractures in shale formations and reduce the possibilities of wellbore stability problems.

Introduction

In numerous drilling projects, characterization and testing of shale formations could play a key role in avoiding severe borehole problems related to shale stability. Before the exposure of problematic shale formations to drilling fluids, an experimental verification of the interaction between fluid components and shale is the best strategy to minimize the rock-fluid interaction and establish a chemical balance. Prediction of the different manifestations of rock-fluid interaction such as dispersion, swelling, dissolution, or fracturing should be done using information extracted from the rock and laboratory experiments with the drilling fluids.

The characterization of shale using petrographic studies is the first step in identifying particular features of the rock which may represent potential causes for instability. The understanding of the structure is important to evaluate the mechanics of its instability and establish means to control it.[1.] The instability mechanics of shale samples are closely linked to the structure and composition of the shale. Massive, fissile, and interbedding structures of shale formations define the direction and internal contact areas where the fluid infiltrates. The mineral composition of the areas where fluids contact the rock defines the rock-chemical potential. This chemical potential should be balanced with the proper chemical selection of drilling fluid components. An understanding of the structure and composition of shale formations is a fundamental step to initiate the process of fluid selection.

The petrographic studies of thin sections facilitate the identification of areas where the rock structure can fail or weaken due to contact with fluids. The presence of micro-fractures, laminations, slickensides, and boundary areas are clues to identifying fragile areas where failure of the rock may occur.

The existence or creation of fissures, fractures, and weak bedding planes can also destabilize shale due to drilling fluids penetration.[2] This mechanism of instability is associated with "brittle shales". This term is applied to the class of shales that appears quite firm and competent when recovered from the core barrel but fall in pieces when placed in water. The pieces, however, do not soften or swell in water.[3]

Other laboratory analyses complement the petrographic analyses of thin sections. X-Ray diffraction (XRD) and cation exchange capacity (CEC) data help to understand the mineral composition and give an indication of the reactivity of the rock based on the content of water-sensitive clays.

The selection of the tests to evaluate the rock-fluid interaction is based on rock characterization. It is necessary to select the correct experiment associated with the instability mechanism. Furthermore, shales behave quite differently when exposed to fluids.[3] Many of the traditional shale tests are focused on evaluating only one type of instability mechanism. Therefore, it is critical to correctly identify the instability mechanism.

2005 CTD Experiences in the Anadarko Basin Shale

During the 2005 program of coiled- tubing drilling (CTD) operations in the Anadarko Basin, Texas, the Cleveland and MSF shale formation which lies above the reservoir zone represented a problematic area. Severe borehole instability problems were encountered during the re-entry of horizontal sidetrack of old wells. The casing exit, build, and lateral CTD program were drilled in one interval. Once formation losses were experienced, sloughing shale was observed at the shakers and fill was encountered on wiper trips. Sidetracks and inability to run completions were some of the main consequences of the borehole instability. The drilling program finished with only 30% of wells completed and some wells were lost afterwards indicating possible hole collapse.

Cleveland Core

A core sample was obtained to derive information about the shale formation and conduct studies to identify the causes of instability and fluid losses. This paper presents the shale stability laboratory study to select the optimum drilling fluid for the CTD operation in the Anadarko Basin.

The core was obtained from the well Bradford C No. 8-723 in Lipscomb County, Texas. The core was taken from 7515- to 7590-ft depth. The core was divided in 1-ft sections and immersed in wax to preserve the original conditions of the rock. **Figure 1** shows the gamma ray data of the core and the assigned names for shale sections (MSF1 through MSF4).

CT scans images were used to select pieces of core for further study. The choice of the samples focused on the selection of representative samples for characterization and intact pieces of shale for stability study in fluids. Features such as the presence of laminations, composition variation, cross-bedding fractures, overall section condition, and texture change were considered. **Table 1** shows the list of samples selected for the characterization.

Characterization

XRD and CEC analyses were conducted for most of the samples selected. Thin-section analyses were done on selected samples which represented important geologic features of the formation. The results of the mineralogy analysis indicated that most of the samples between 7516 and 7568 ft contain 40–50% clay minerals including smectite, chlorite, and illite. Quartz and feldspar content was around 40%. A decrease in the clay content is observed in the samples from 7566 to 7576 ft (sandstone zone). **Figure 2** shows the results of the XRD.

The CEC data showed that the samples from the shale sections had low-to-medium reactivity. The highest value (13 meq/100 g) corresponds to the sample at 7541 ft. The CEC of samples from the sandstone zone were low (less than 5 meq/100 g). **Figure 3** shows the results of the CEC analyses.

Most of the samples selected for thin-section analysis were classified as fissile clay shale; however the structure of the rock exhibited some variations along the core. The sections MSF1 and MFS2 were characterized mainly by the predominance of fine laminations and clay-sized material. Some samples exhibited an extreme parallelism of clay minerals (**Figure 4.**) The marked presence of pyrite crystals (framboids) was noted in the sample from 7540 – 7541 ft (**Figure 5**.). Micro-fractures extended along the bedding plane were observed in most of the samples. The typical fracture width ranged between 5 –10 microns.

The thin sections from MSF3 revealed some particular features of the rock structure in this zone. Alternating silty beds in the clay shale were common. Wavy structure and silty layers or blocks were found in some samples. **Figure 6** illustrates an example of the wavy structures. Pre-existing fractures were also observed in this section. The fractures tended to extend along the bedding planes and surround the silty layers. The typical fracture width in this section is 5 – 10 microns. The MSF3 was reported as the most problematic section during the 2005 CTD operation. The boundary zones of interbedded siltstone in the clay shale formation could represent weak planes that would tend to become fragile with fluid exposure.

The MSF4 section exhibited a transitional zone with the presence of siltstone with abundant shale beds. Some fractures tended to develop in the shaly materials. Most of the zone corresponded to sandstone with a low clay content (~3%).

One significant characteristic found in the majority of the thin sections was the presence of the micro-fractures. These micro-fractures were identified as potential failure areas and were directly related to the instability mechanism of this formation.

Fracture Development Test

Based on the information obtained from the characterization of the core, the Fracture Development test[4] was selected to evaluate the stability of this rock formation in fluids. This test focuses on low–medium reactive/hard shale formations, such as found in the thin-section analysis, where stability problems are more related to propagation of pre-existing fractures and development of new fractures. The test is a systematic laboratory technique used to evaluate the stability of hard shale formations exposed to drilling fluids. The method combines two techniques: time-lapse photography and microscopic analysis of thin sections. Time-lapse photography is used to document the visible changes in the rock during fluid exposure. The microscopic analysis technique is used to observe the changes in the micro-structure of the rock after the fluid exposure through standard petrographic thin sections.

The experiments were conducted according to the following procedure:

Sample Preparation

1. Identify the basic petrologic features of the samples such as angle and spacing of lamination, direction of crossbedding, presence of pre-existing fractures, change in grain, etc.

2. Saw the rock sample into cubic pieces of approximately equal size using a saw with diamond blade for dry cutting applications. The maximum sample dimension (length) varied depending of the size of the piece of core and the condition of the rock, but in general terms the maximum size ranged between 1 and 2 inches.

Fluid-Exposure Procedure

1. Place each piece of rock in an optically clear square container. Keep one piece of sample for comparison purposes (unexposed sample).
2. Add the fluids into the containers. Ambient conditions (temperature and pressure) are maintained throughout the test.
3. **Clear fluids:** Take photos at regular pre-determined intervals. Carefully observe and record photographically the visible changes in the rock integrity such as fracture development, cracking, crumbling, and precipitation of material on the surface of the sample.

   Whole drilling fluids (containing solids, polymers, and other additives): Take an initial photo before fluid exposure and a final photo after fluid exposure. Photographically record any visible change in the structure of the rock.
4. At the end of the test, remove the samples from the containers and allow the samples to dry at room temperature overnight.

Post-Fluid-Exposure Analysis

1. Prepare thin sections of the samples (including the unexposed sample). This procedure includes impregnation of the samples with blue dye epoxy, cutting and grinding process in oil.
2. Carefully examine the thin sections with a petrographic microscope. Record and document the main features of the fracture network for each sample.
3. Compare the original sample and the sample exposed to identify the changes in the rock structure that occurred from exposure to fluids.

Fracture Development Test Results

An initial test was conducted using clear fluids to document and analyze the rock-fluid interaction. Samples from MSF1, 2, and 3 were exposed to the fluids for 24 hr. The clear fluids consisted of solutions of inhibitor products (amine-based inhibitors and KCl) in freshwater. One test was conducted with mineral oil.

The rock-fluid interaction was characterized by the development of fractures mainly along the bedding planes. The fracturing occurred during the first hours of the test and then no more changes were evident. The section MFS3 seemed to be the most affected after the fluid exposure to water-based fluids. The fracturing appeared to be more severe in MSF3 than in the other sections. **Figure 7** shows microphotographs of samples from MSF1, 2, and 3 exposed to freshwater. The solution of 5% KCl exhibited the best overall performance for water-based fluids. The amine-based fluids did not help to control the fracturing of the samples. Evidence of fracture enlargement and development of new multiple fractures was found. The sample exposed to mineral oil remained stable and development of fractures was not observed. **Figure 8** shows the photomicrographs of samples from MSF3 exposed to 5% KCl, amine-based inhibitor, and mineral oil.

A second set of tests using whole fluids was conducted with samples from MSF2 to document and analyze the rock interaction with drilling fluids. The samples were exposed to water-based and oil-based drilling fluids. Two water-based drilling fluids with polymers were formulated; one with 5% KCl salt and the other with 3% NaCl. The fluid with NaCl was included as a comparison for fluids used in the 2005 CTD operation. The oil-based fluids were formulated with the same additives but different $CaCl_2$ concentrations in the internal phase. The salt concentrations used were 20, 25, 30, and 35% with the purpose of covering a range of water activities between 0.5 – 0.83. Mineral oil was used as the base fluid for these formulations. Measurements of the water activity (A_w) of rock pieces were obtained using the standard electrohygrometer method and the water adsorption isotherm.[5] The A_w for the samples was 0.52 – 0.57.

Core samples were exposed to the whole drilling fluid for 48 hr; photos of the samples were taken before and after the exposure. Enlargement of fractures was evident in the sample exposed to the fluid containing NaCl; the sample exposed to the fluid containing KCl did not exhibit a significant change (**Figure 9).**

Using thin-section analyses, the enlargement of fractures and a general comparison of the fracture network was evaluated. Presence of fractures mainly along the bedding plane and few intersecting fractures were the principal characteristics of the fracture network of the unexposed core sample from MSF2. Enlargement of fractures was confirmed after the comparison of the fracture widths of the unexposed core piece and the core samples exposed to fluids. The maximum fracture width of the unexposed sample was approximately 45 microns. Large fractures extended along the thin section and fractures widths larger than 100 microns were identified in the sample exposed to NaCl fluid. The largest fracture width measured was approximately 315 microns. Intersected fractures and fractures extending diagonal and perpendicular to the bedding plane were also common. The thin section of core exposed to the KCl fluid showed some development of diagonal and intersecting fractures in the micro-size range (<10 microns). However, enlargement of pre-existing fractures was not found. **Figure 10** shows photos of the thin sections of the unexposed sample, and the two samples exposed to water-based fluids. The enlargement of fractures in the sample exposed to water-based fluid with NaCl is clear and it is an indication of the weakness of rock structure.

The samples exposed to oil-based fluids remained stable and visible changes were not identified in the samples after fluid exposure. The general characteristics of the fracture network of the samples exposed were very similar to the reference sample (no fluid exposure). Indications of enlargement or development of new fractures was not found.

In general terms, the structure of the sample remained unaffected and the rock seemed to be insensitive to the changes of $CaCl_2$ concentrations between 20 – 35% when used with oil-based fluids.

2007 Field Experiences in the Anadarko Basin Shale

For the 2007 program, the drilling team planned new strategies to avoid the stability problem encountered in 2005. The most important change for drilling fluids was the selection of the polymeric system with 5% KCl, in the place of 3% NaCl, to minimize the shale-fluid interactions and reduce the potential instability problems. Also an equivalent density of 9.2 – 9.4 lb/gal was maintained until the liner is run below the MSF 3 shale.

Reports of the 2007 drilling operations have shown a significant reduction in the wellbore instability as compared with the 2005 program. The wells have been drilled with better management of fluid densities for the different sections and the addition of KCl in the drilling fluid has shown good results in terms of shale inhibition. 100% of the wells have been successfully completed. Minor shale instability issues have occurred and they have been effectively resolved with adjustment of the drilling fluid density.

Conclusions

The characterization and evaluation of the behavior of shale formations with drilling fluids are fundamental steps in the process of solving or anticipating wellbore stability problems. The understanding of the geologic features of shale formations and the importance of the inclusion of this information in the drilling fluid selection represents an important approach to the prediction and preparation for drilling operations in problematic shale sections. This paper showed how previous shale stability problems encountered in the coiled-tubing drilling operation in the Anadarko Basin were overcome with a more complete understanding of the characteristics and instability mechanisms of the Cleveland and MSF shale formation. The formulation of drilling fluids based on the information obtained from the rock helped to select the proper inhibitor additives that reduced the fracture propagation which was identified as the principal shale instability mechanism in this formation.

Acknowledgments

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2. Manohar, L. "Shale Stability: Drilling Fluid Interaction and Shale Strength." SPE 54356, SPE Latin American and Caribbean Petroleum Engineering Conference, Caracas, Venezuela, April 21-23, 1999.
3. Darley, H.C.H. "A Laboratory Investigation of Borehole Stability." *Journal of Petroleum Technology,* (July 1969) 883.
4. Gomez, S. and He, W. "Laboratory Method to Evaluate Fracture Development in Hard Shale Formations Exposed to Drilling Fluids." AADE Fluid Conference, Houston, April 11-12, 2006.
5. *ASTM C1498-04a: Standard Test Method for Hygroscopic Sorption Isotherms of Building Materials.* ASTM International (2004). Available from www.astm.org (last accessed February 20, 2008.)

Table 1 – Pieces of core selected for the study

Sample #	Depth (ft)	Core Piece or Whole core (1ft)	Section
1	7515.80-7516.00	Core Piece	MSF1
2	7522.00-7523.00	Whole Core	MSF1
3	7523.00-7524.00	Whole Core	MSF1
4	7534.90-7535.00	Core Piece	MSF1
5	7535.80-7536.00	Core Piece	MSF1
6	7540.00-7541.00	Whole Core	MSF2
7	7545.00-7546.00	Whole Core	MSF2
8	7550.50-7550.70	Core Piece	MSF3
9	7552.90-7553.00	Core Piece	MSF3
10	7553.00-7554.00	Whole Core	MSF3
11	7557.55-7558.00	Core Piece	MSF3
12	7565.85-7566.00	Core Piece	MSF4
13	7572.90-7573.00	Core Piece	MSF4
14 & 15	7573.80-7574.00	2 Core Pieces	MSF4
16	7575.92-7576.00	Core Piece	MSF4
17	7576.96-7577.00	Core Piece	MSF4

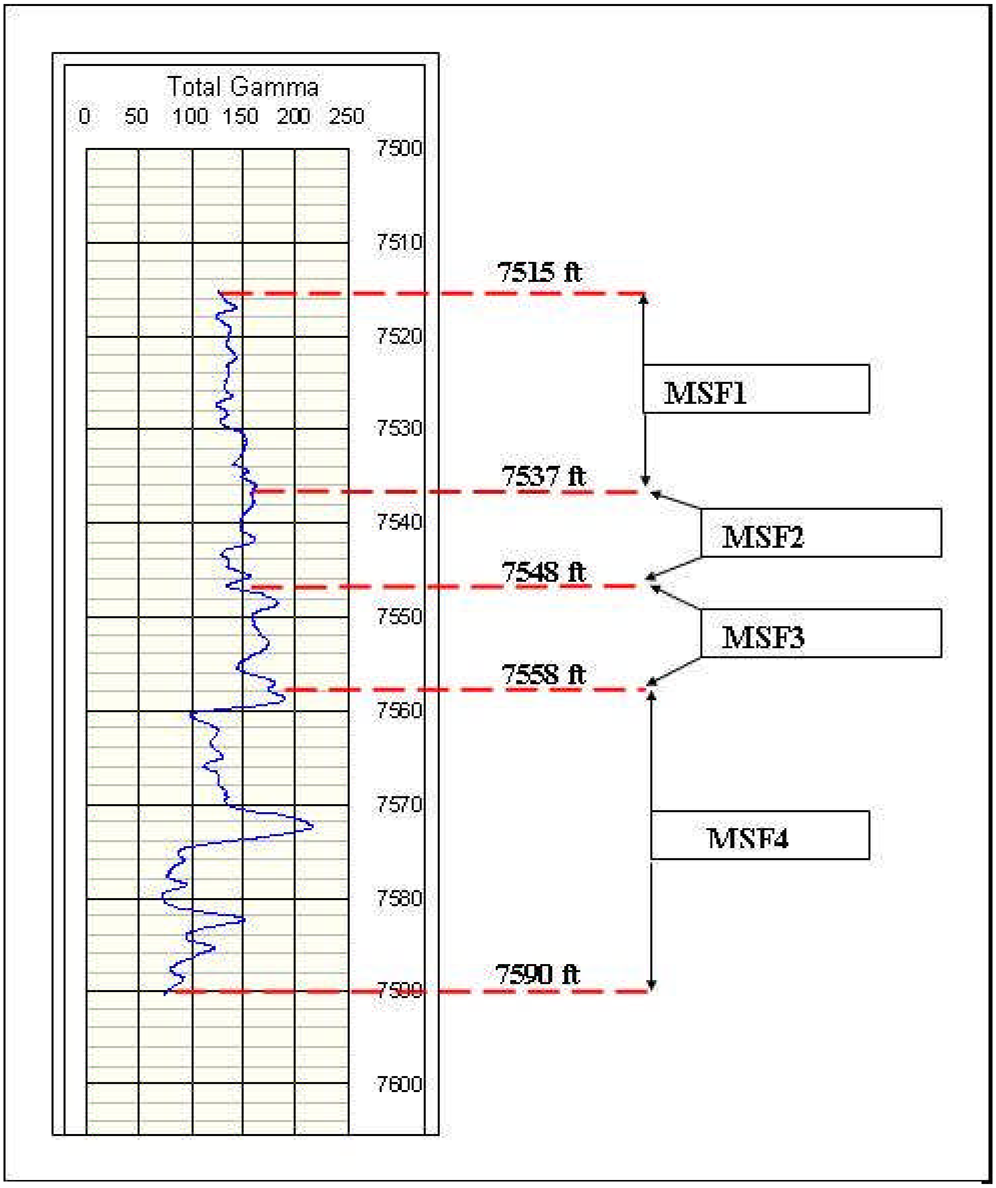


Figure1 – Gamma ray of Cleveland Core well Bradford C No. 8-723 in Lipscomb County, Texas,

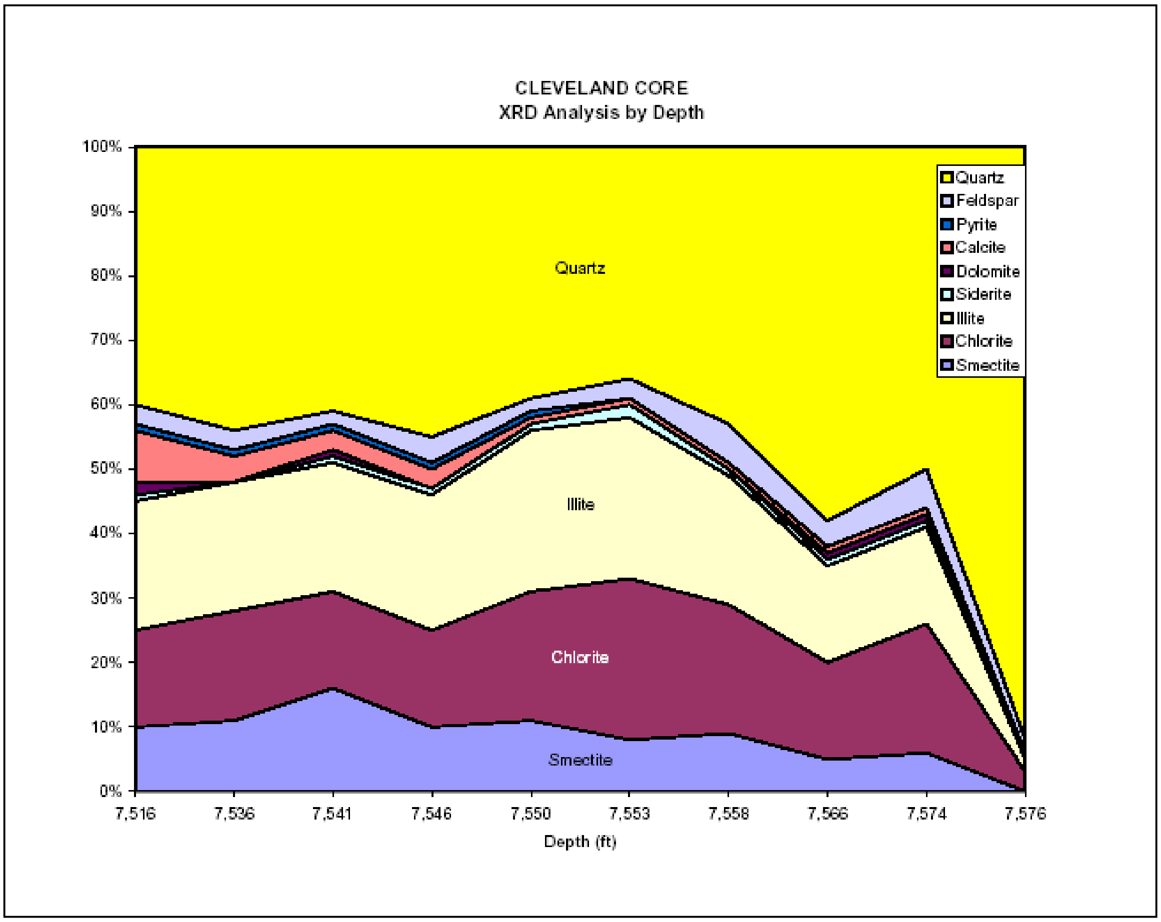


Figure 2 – Cleveland Core mineralogy results.

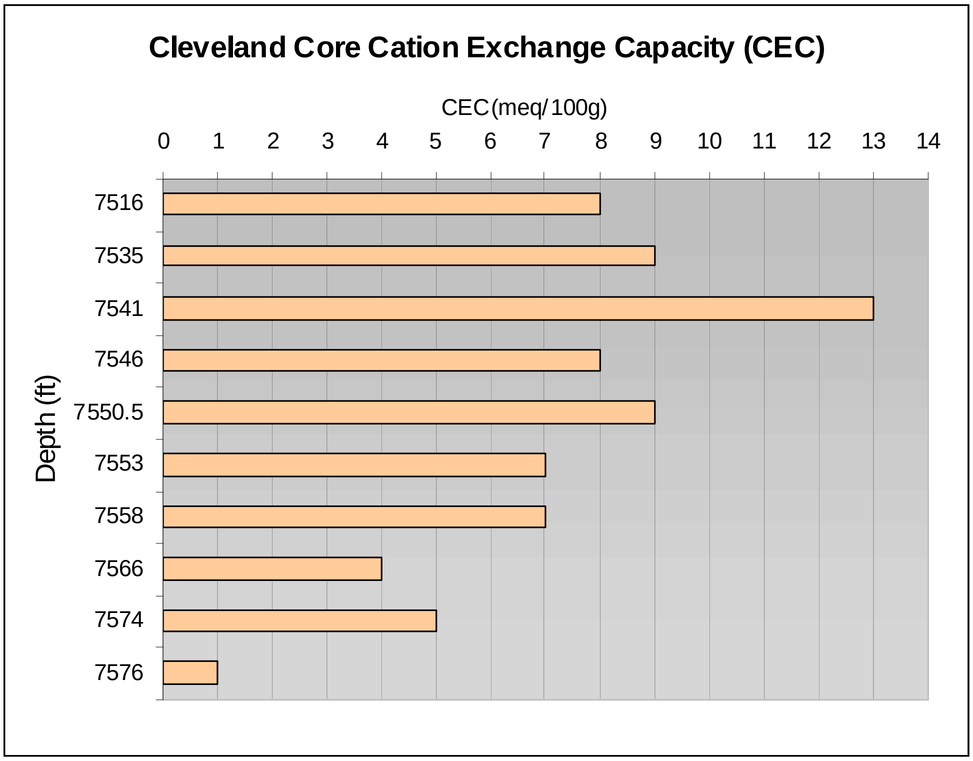


Figure 3 – Cleveland Core cation exchange capacity (CEC) data.

Figure 4 – Section MSF1 (7535.80 – 7536 ft). Fissile clay shale. Note extreme parallelism of clay minerals, fine lamination, and marked predominance of clay-sized materials.

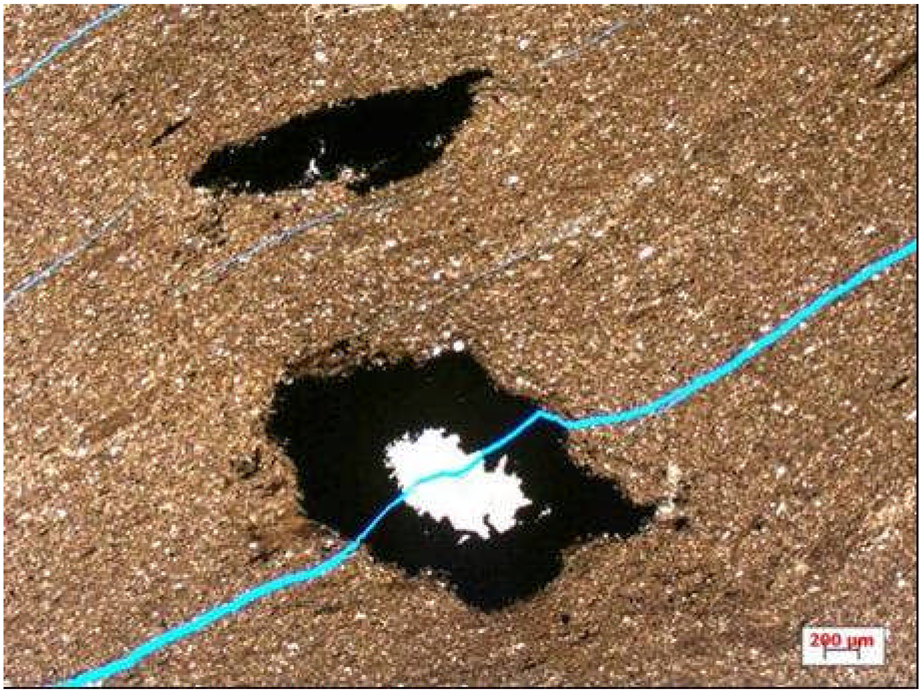


Figure 5 – Section MSF2 (7540 – 7541 ft). Fissile clay shale. Note fine lamination and a marked predominance of clay-sized materials. There are framboids which are small clusters of smaller pyrite crystals. Fractures develop in shale along the bedding planes.

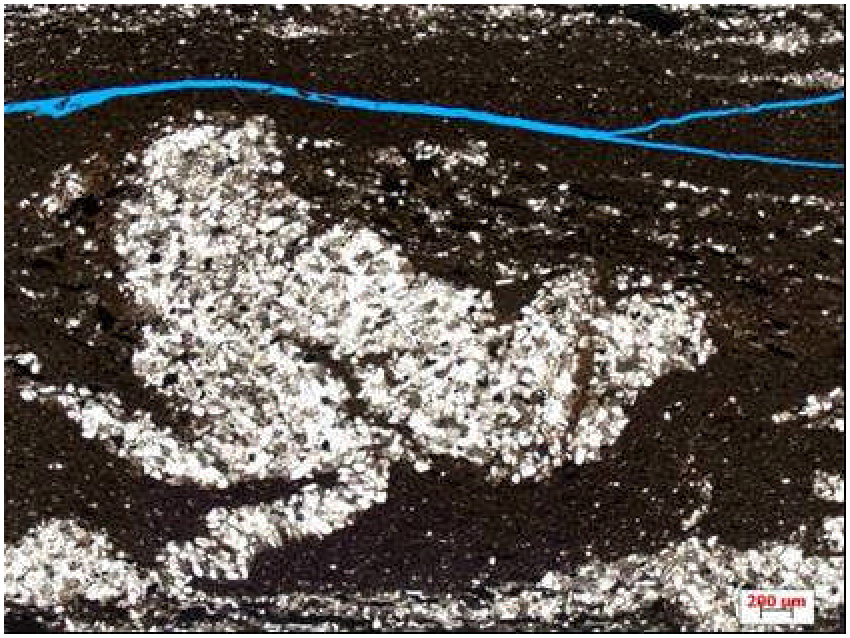


Figure 6 – MSF3 (7552.90 – 7553 ft). Fissile clay shale with alternating silty beddings. Note fine lamination in shale and a marked predominance of clay-sized materials and wavy structures. Silty layers or blocks could be accumulated owing to storm activity. Fractures develop in shale along the bedding planes.

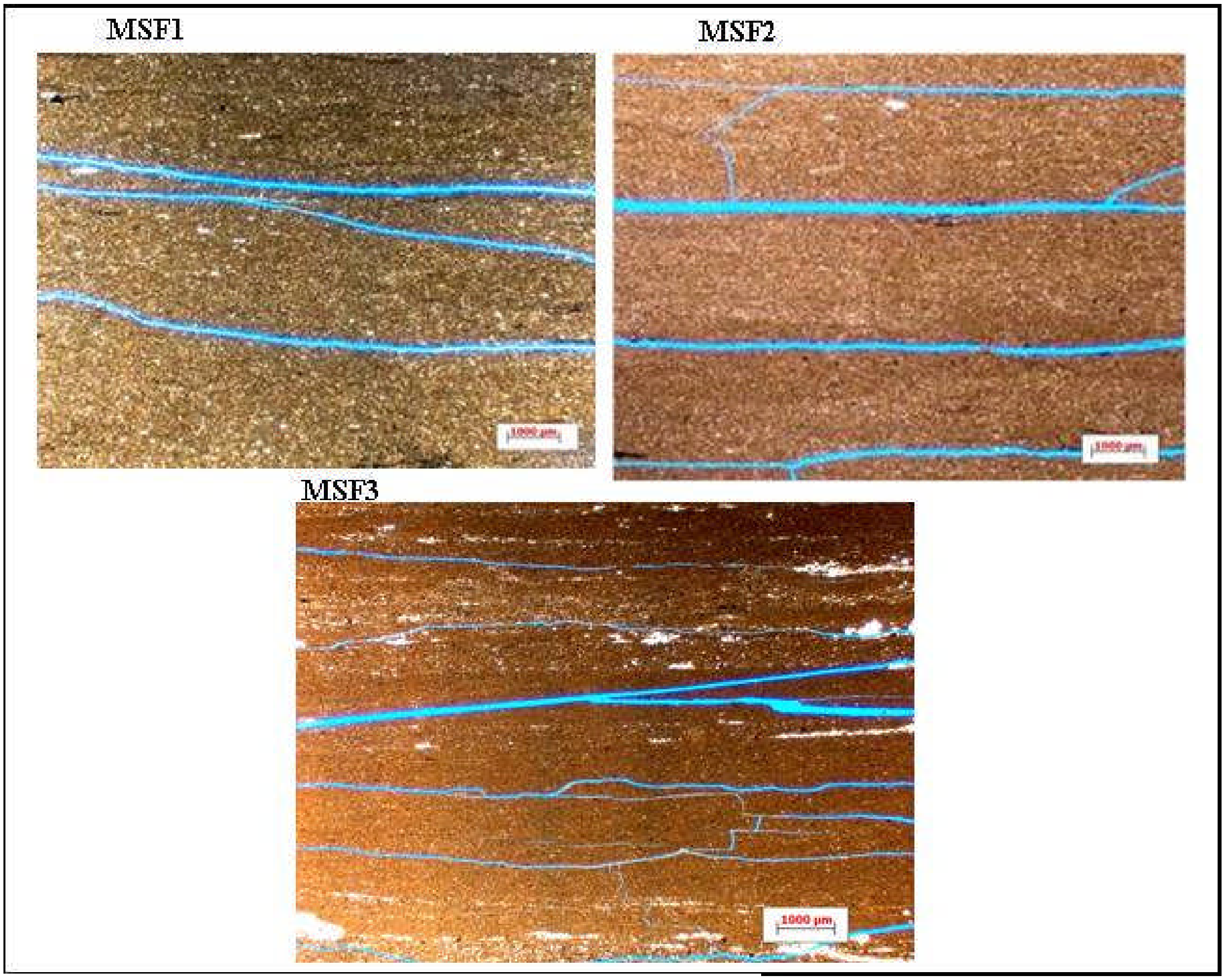


Figure 7 - Micro-photographs of samples exposed to freshwater.

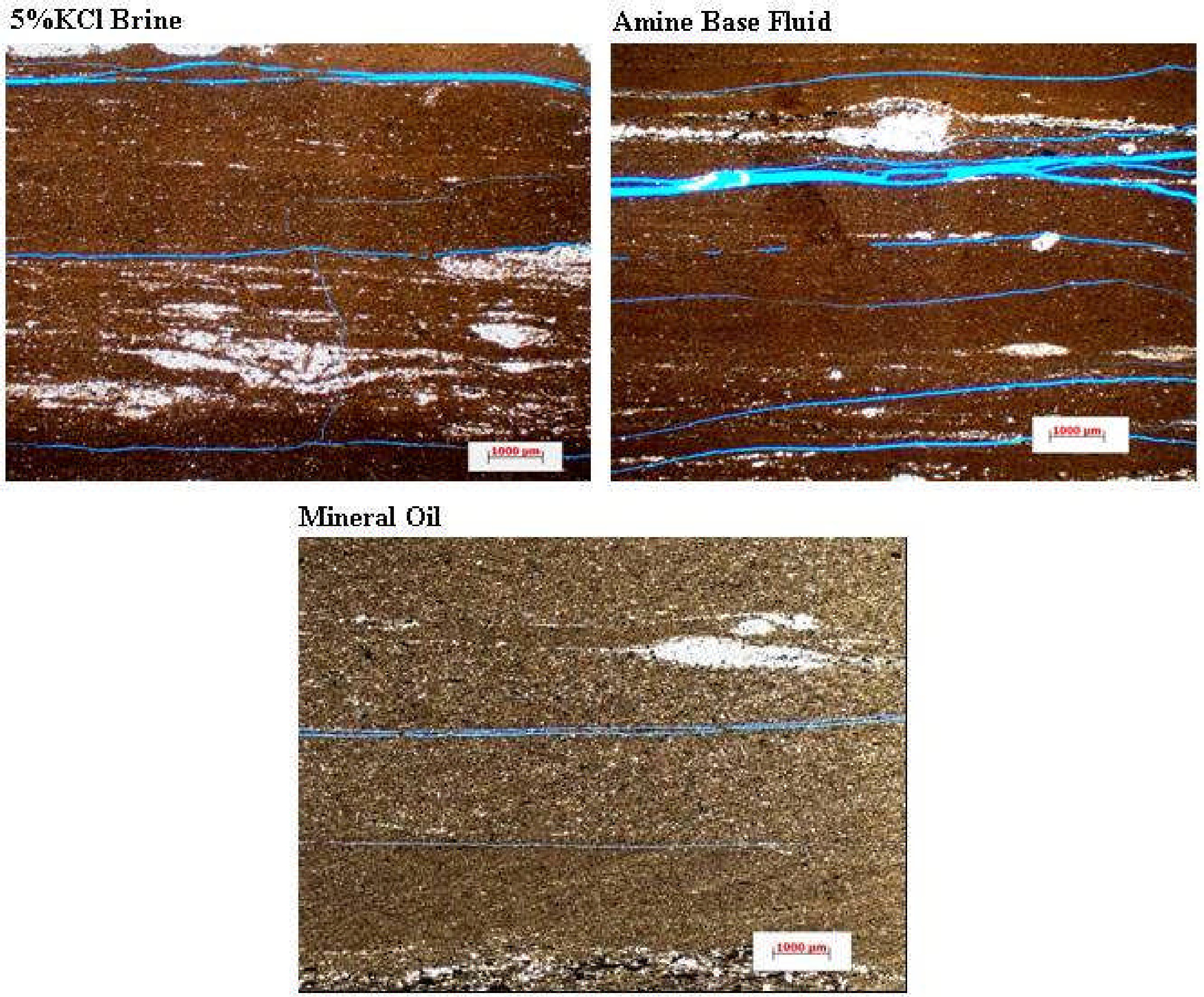


Figure 8 - Micro-photographs of samples from MSF3 section after fluid exposure.

Water based fluid with 3%NaCl

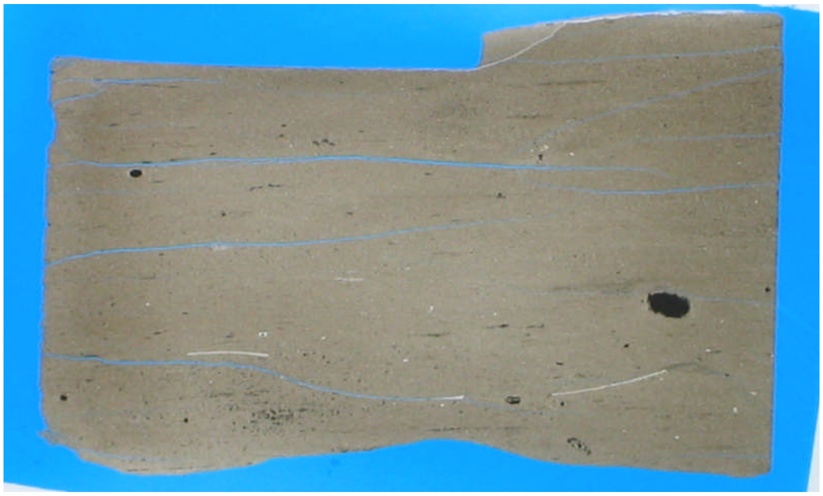
Before fluid exposure After fluid exposure

Water based fluid with 5% KCl

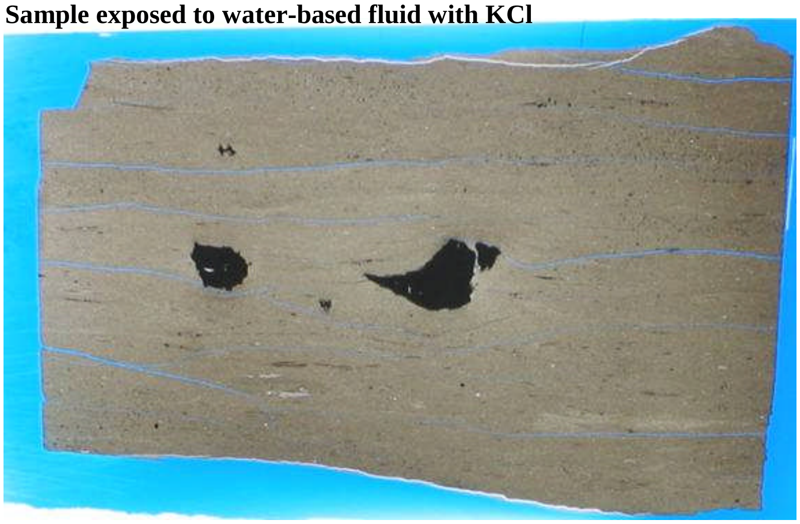
Before fluid exposure After fluid exposure

Figure 9 – Pieces of core before and after exposure to water-based fluids. Presence of fractures in the sample exposed to water-based fluid with NaCl. These fractures are readily visible to the naked aye. Few small fractures are visible in the sample exposed to the water-based fluid with KCl.

Reference sample. No fluid exposure.



Sample exposed to water-based fluid with KCl



Sample exposed to water-based fluid with NaCl

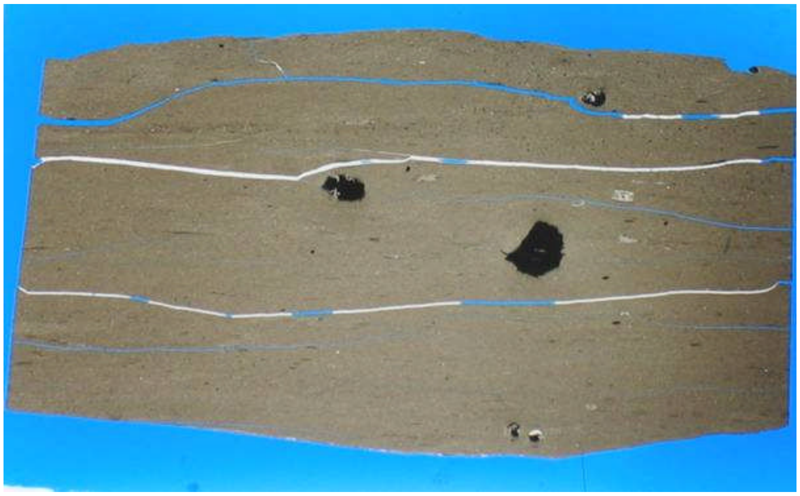


Figure 10 - Thin-section photos of samples from MSF2 section. Note the enlargement of fractures in the sample exposed to water-based fluid with NaCl.