AADE 01-NC-HO-44

Laboratory Pore Pressure Transmission Testing of Shale

Cal Stowe, William Halliday, Tao Xiang, Dennis Clapper of Baker Hughes INTEQ, Keith Morton, Shawna Hartman of Chevron Petroleum Technology Company

Abstract

Shale stability has always been an integral part of high performance water-based drilling fluid design. Shale stability is characterized by various laboratory tests which measure shale dispersion, hardness, hydration/swelling, bentonite inhibition, ionic exchange, volume increases, borehole stability, and more recent pore pressure transmission rates. All of this data has been used in the design of current high performance water-based fluids, which enhance borehole stability.

Initial pore pressure experiments verified and advanced the borehole stabilizing ability of cloud point glycol and precipitant chemistries. Improvements in pore pressure transmission testing equipment and techniques now provide more complete evaluation of new water-based fluids. The ability to measure pore pressure transmission in preserved shale core is advancing our understanding of chemicals required to maintain wellbore stability. A water-based fluid must seal shale formations during drilling in order to maintain well-bore stability. Recent pore pressure transmission work has targeted improved water-based fluid shale sealing to more closely match oil-based pore pressure transmission characteristics. A synergistic effect between some types of polymers and precipitant chemistry has produced an advanced water-based drilling fluid concept with improved pore pressure transmission characteristics over current water-based systems.

Introduction

Optimizing high performance water-base mud design is commonly at the forefront of many drilling fluid service and oil operating companies’ wish list due to invert emulsion fluid limitations. Invert emulsion fluids formulated with traditional diesel, mineral or the newer synthetic oils provide the best shale inhibition, borehole stability, and lubricity. However limitations of these fluids include environmental concerns, economics, lost circulation tendencies, kick detection, and geophysical evaluation difficulties. Increased environmental concerns and liabilities continue to create an industry need for water-based fluids to supplement or replace the performance-leading invert emulsion muds.

Today water-based drilling fluid technology continues to evolve. The search for a water-based mud to match invert emulsion performance for drilling shale has lacked a standard test to measure borehole stabilizing ability. Many laboratory procedures and specialized devices have been used over the years for evaluating drilling fluids in regard to shale stability. Testing has ranged from simple bentonite swelling tests to sophisticated triaxial testing with simulated borehole conditions.[1] Shale wafer testing[2], capillary suction[3], cuttings disintegration[4], axial stress tests[5], and dielectric constant measurements[6] are just a few of the shale stability tests that have been used over the years. Newer techniques include measurement of pressure transmission through a shale specimen induced by fluid invasion.[7,8,9]

It is recognized that sufficient borehole pressure will stabilize a shale borehole up to the frac pressure. When mud or liquid invades the shale, the pressure in the pores rises and the pressure differential between the mud column and the shale falls. With the drop in differential pressure, the shale is no longer supported and can easily break off and fall into the well bore. Since fracture gradients often preclude raising the mud weight, a drilling fluid that maintains the overbalance pressure is desirable.

Background

The primary purpose of the pore pressure transmission tester is evaluation of the borehole stabilizing quality of a drilling fluid. The most important factor in maintaining borehole stability is to prevent pressure rise in the shale matrix, thus maintaining overbalance pressure support of the borehole wall. An ideal drilling fluid for shale stability would have zero fluid invasion. A device capable of measuring pressure increase downstream of a shale core when a small amount of fluid enters the upstream end is an alternative method of evaluating borehole stability. No build up of pressure downstream of the core indicates the core face in contact with the fluid is protected, and there is no transmission of fluid through the core. Conversely, pressure increase downstream indicates fluid transmission is taking place.

Pore pressure transmission (PPT) testing measures the formation pore pressure increase from filtrate invasion in very low permeability formations such as shales. In highly permeable formations the pressure rise from filtrate flow is rapidly dissipated in the formation volume and pore pressure is not affected. However in very low permeability formations, the pressure increase from filtrate invasion declines very slowly and the pore pressure continues to increase with additional filtrate flow. This pore pressure increase reduces the effective over balance pressure. Overbalance pressure decline is exaggerated by wall fractures from drilling. These fractures increase near - wellbore permeability resulting in rapid pressure increase inside the wall. Reduced overbalance tends to destabilize the wellbore and promote sloughing.

Shale is created with layers of sediment under water. Over time the weight of the sediment drives out the excess water and bonds form between the sediment particles. Since the sediment composition varies with time, distinct layers are created called bedding planes. The interface between the bedding planes has greater permeability than within the planes. Therefore shales have substantially greater permeability parallel to the bedding planes than perpendicular to the bedding planes. Previous measurements have shown the parallel bedding plane orientation has about five times the permeability of the perpendicular orientation. All of the tests discussed in this paper run parallel to the bedding planes with a low confining pressure to simulate high permeability or microfractured shales.

Previous studies have reported the following observations concerning water- based muds:

1. Pore pressure rise rate in shale is a function of driving pressure, diffusion, and osmosis.

2. Brine type and concentration significantly impact pore pressure invasion rate in shale.

3. Clouding glycol within the shale pores produces a more effective block than having the glycol in solution or clouding it outside of the shale.

4. Precipitating chemistry, especially in combination with salt and polymer significantly decreases pore pressure rise in shale.

Invert emulsion drilling fluids provide the following pore pressure transmissioncharactreristics:

1. Invert emulsion filtrate does enter shale pore spaces easily due to capillary entry pressure and thus pore pressue invasion is minimal.

2. The internal salt phase produces an osmotic pressure that is a driving force for water movement from shale to mud.

Equipment

The PPT test is performed on a custom designed and constructed pore pressure transmission device. This device is based on a modified 1500 psi Hassler cell (Fig. 1). A preserved Pierre II shale plug 1 inch in diameter x 0.9 inch long is placed between two pistons and the circumference of the shale and pistons sealed with a rubber sleeve. The plug is oriented with the bedding planes in the parallel or high permeability direction.

Drilling fluid at 300 psi is displaced through the upstream piston (borehole side) and seawater at 50 psi is displaced through the downstream piston (formation side). The seawater in the downstream piston is contained with a valve. As mud filtrate enters the borehole end of the plug connate water in the shale is displaced into the formation piston. This additional water compresses the water inside the piston causing the pressure to rise. The pressure increase in the formation piston water is measured as formation pressure rise.

Since water has low compressiblity, minute liquid invasion into the core causes a large pressure increase. This makes the cell sufficiently sensitive to measure formation pressure rise in shales which have near zero permeability. During the test the pressure is automatically logged and plotted vs. time.

The low pressure side of the core (formation side) is fitted with a 1 liter, 2000 psi., stainless steel accumulator to provide back pressure. The high pressure side of the core is connected to two similar accumulators, one for pore fluid, and one for the test fluid. The pressure in each accumulator is controlled with a manual regulator fed by a 2200 psi nitrogen bottle. A schematic of the overall apparatus can be seen in Figure 2.

The cell is enclosed in an insulated chamber and the temperature maintained with a 200 watt heater. The heater is controlled with a Dwyer temperature controller driving a Control Concepts phase angle SCR control unit. Temperature control is accurate to +/-0.09°F [+/-

0.05°C]. The pressures are monitored with Validyne transducers.

New Approach to Control of Pore Pressure Transmission

Since the development of pore pressure transmission testing, the effects of various chemical additives on pore pressure transmission rates have been evaluated. Testing has focused primarily on the performance of salts, glycols, and precipating agents such as silicates and aluminum complexes. While silicate fluids have been found to be especially effective in reducing pore pressure transmission rate, they are not widely used due to operational limitations. Although lower pore pressure transmission rates have been demonstrated for salts, glycols, and aluminum complexing agents, these products still do not approach invert emulsion performance. Improvements in PPT test equipment and methods have accompanied the search for more effective water-based mud systems.

A new formulation approach was used to enhance the shale sealing of water-based mud systems. A sealing polymer was selected to provide a source of small, deformable particles for sealing the shale and blocking the microfractures. The first sealing polymers - SP1 and SP2 were evaluated in several different formulations during preliminary tests for this project. Early results indicated: 1) SP alone was not sufficient to decrease pore pressure transmission rates; 2) incompatibility between glycols and SP produced increased PPT rates.

Because the initial test results indicated that incorporation of an SP alone did not produce PPT rate reduction, a search was conducted for a compatible additive to test with the SP. A resin complex (RC) was tested along with a chemically treated SP. The effectiveness of the SP/RC combination is illustrated in Figure 3 where the pore pressure control of this synergistic combination is compared to a conventional 20% sodium chloride / PHPA fluid and a synthetic invert emulsion fluid. When the RC was tested alone, the control was much less effective. The order of PPT transmission rate reduction, beginning with the least effective fluid was:

1. Base salt/PHPA
2. Base plus RC
3. Base plus RC with SP1
4. Base plus RC with SP2
5. Synthetic mud

The presence of both RC and SP was essential to the plugging mechanism. It is believed that a film comprised mostly of RC is deposited on the shale surface. The presence of the RC creates a surface that is conducive to deposition of SP which forms a film that seals defects in the shale. It is believed that the differences in performance between SP1 and SP2 are attributable to differences in particle size distribution as well as chemistry.

Additional tests were conducted to further evaluate the effectiveness of the SP/RC combination. Standard procedure is to circulate the mud about seven hours and allow it to stop during the night. Four or five hours without circulation elapses before the test is started in the morning. This eliminates pressure drift due to temperature effects by allowing temperature variation from circulation to equilibrate. Because of the complex blocking/plugging mechanism believed to occur with the combination of the SP and RC, additional tests were conducted with intermittant circulation past the core face after full differential pressure was established. Circulation at full differential pressure was found to be a critical element of the sealing polymer plugging mechanism. This effect was explored in the tests with SP2.

When the test started the formation pressure fell from 50 psi to zero, increasing the differential pressure from 250 to 300 psi . In about 30 hours the plug began to leak and the formation pressure rose. However, additional circulation sealed the leak in an hour and the pressure again fell to zero. In previous tests when the circulation was stopped after an hour, the plug started leaking again after another 30 hours.

In this test circulation was restarted after the pressure rose to 60 psi in 70 hours. However, circulation was maintained five hours instead of one as before. With a few hours of continued circulation after the greater pressure differential was established; the seal was more stable. The pressure only rose a few psi in 45 hours.

After these tests the core samples were retrieved and examined. A photomicrograph of the plug face (Fig 4) showed sealing polymer accumulation along microcracks in the shale. As the volume and velocity of filtration flow into these cracks is very small, filtration alone cannot account for the SP2 accumulation at the crack throat. Inside these cracks the clay surface area to filtrate volume ratio is very large resulting in heavy RC precipitation. The presence of RC leads to heavy SP2 accumulation at the crack throat. When sufficient SP2 is deposited to bridge the crack opening, the fracture is sealed and differential pressure is established across the seal. This differential pressure consolidates the SP2 deposit into a solid seal. Increasing the differential pressure apparently causes this seal to deform over time (about 30 hours) and /or grows additional cracks in the shale and the shale begins to leak. However, additional circulation rapidly sealed the leaks and reestablished the seal. Circulating after the full differential pressure was reached formed a stable seal with only a small pressure rise.

Figures 5-7 are photomicrographs of the borehole face of the shale plug from the SP2 PPT tests shown in Fig. 3. As the filtrate invades the core, RC is precipitated, and the SP3 has strong attraction for these precipitates. The SP3 and RC can be identified as lighter and darker shaded areas on the photographs. In Figures 6 and 7 cracks that have been sealed by the additives are visible.

Figure 8 shows a cross section of the shale. The thin dark line is the penetration of the RC precipitate into the shale structure. The layer thickness is 0.001 in. to 0.002 in. thick.

Figure 9 shows a cross sections of fractures in the shale. These were prepared by splitting existing cracks and photographing the section. This photograph shows a thin layer of filtrate precipitation in a narrow crack. Since the layer is thin it appears as a darker, gray area.

A typical formulation with corresponding properties of a SP/RC drilling fluid can be found in Table 1. These fluids can be formulated with convetional fluid loss control additives, viscosifiers, thinners, encapsulating polymer, etc. that are common to most water based muds. Typical salts such as NaCl or KCl can be used for further inhibition. Satisfactory fluid properties can be achieved with these formulations up to 300°F and 16 lb/gal. Higher limits may be possible but have not been tested.

Conclusions

1. The addition of a sealing polymer/resin complex additive to a water-based mud can produce significant improvement in PPT performance.
2. The SP forms deposits with structural integrity at the crack throats that block leakage into the cracks.
3. SP without the presence of the resin complex precipitate does not have an effect.
4. The ability of SP to reduce pore pressure transmission rate appears to be a function of particle size since flocculated SP does not reduce PPT rate.

Acknowledgements

The authors would like to thank the management of Baker Hughes INTEQ and Chevron for permission to publish this paper.

References

1. Darley, H.C.H., “A Laboratory Investigation of Borehole Stability,” J. Petrol. Technol. (July, 1969). 883-892; Trans AIME, vol. 246.
2. Chesser, B. G., “Design Considerations for an Inhibitive and Stable Water-Based Mud System,” IADC/SPE 14249, September 1985.
3. Wilcox, R. D., et al., “Filtration Method Characterizes Dispersive Properties of Shales,” SPE Drilling Engineering, June 1987.
4. Bol, G. M., “The Effect of Various Polymers and Salts on Borehole and Cutting Stability in Water-Base Sahle Drilling Fluids,” IADC/SPE 14757, February 1986.
5. Chenevert, M.E., Osisanya, S., “Shale Testing Procedures for the Prevention of Bore Hole collapse,” University of Texas Research Paper, 1990
6. Steiger R.P., Leung, P. K., “Quantitative Determination of the Mechanical Properties of Shales,” SPE 18-24, October 1988.
7. Stowe, C., et al, “Mechanical Effect of Drilling Fluid on Wellbore Stability”, AADE, 1999
8. Van Oort, et. Al., “Criitical Parameters in Modeling Chemical Aspects of Borehole Stability in Shales and Designing Improved Waer-Based Drilling Fluids, SPE 28309, 69th Annual Technical Conference, Sept. 1994.
9. Bol, G. M., et al, “Borehole Stability in Shales, SPE 24975, Eurpean Petroleum Conference, November 1992.

Fig. 1 Hassler style pore pressure transmission cell.

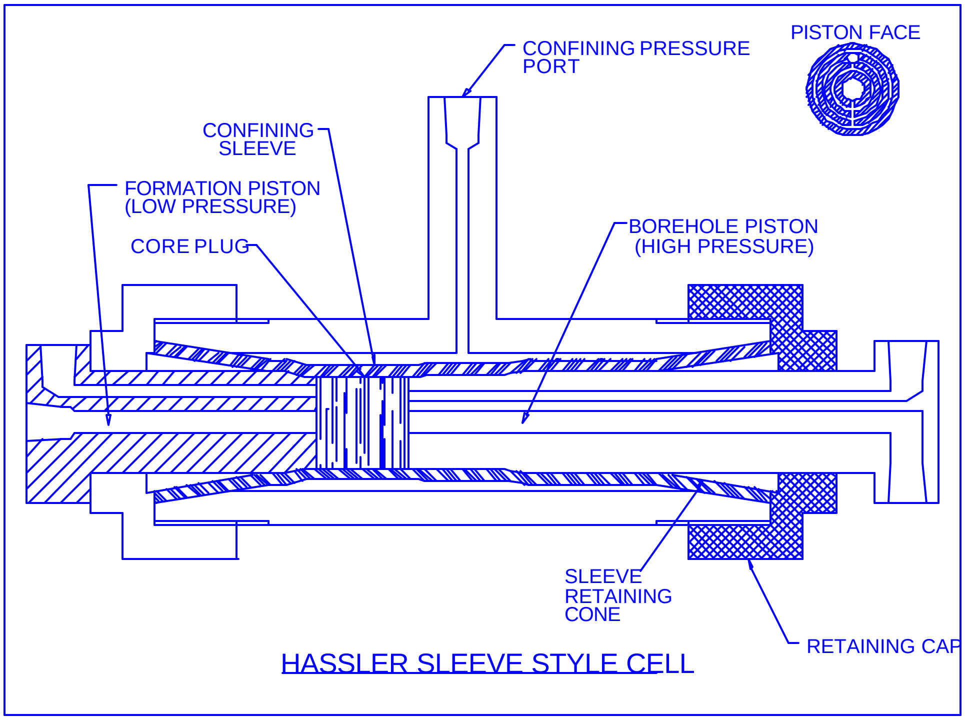

Fig. 2 Schematic diagram of pore pressure transmission apparatus.

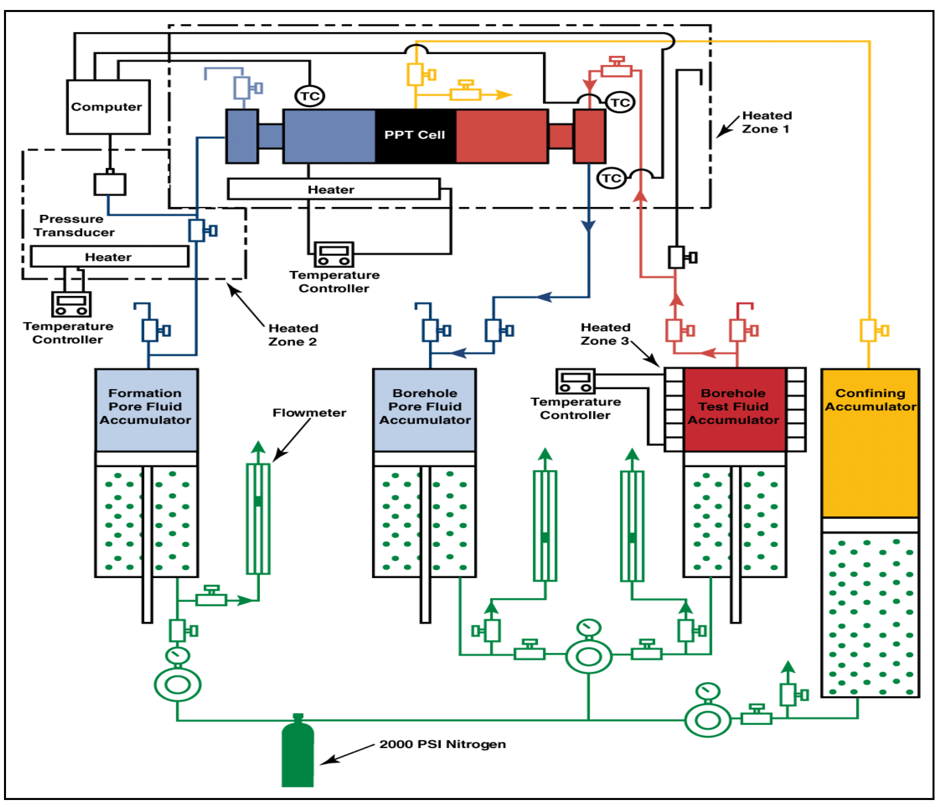

Fig. 3 Pore pressure tranmission rates for experimental additives.

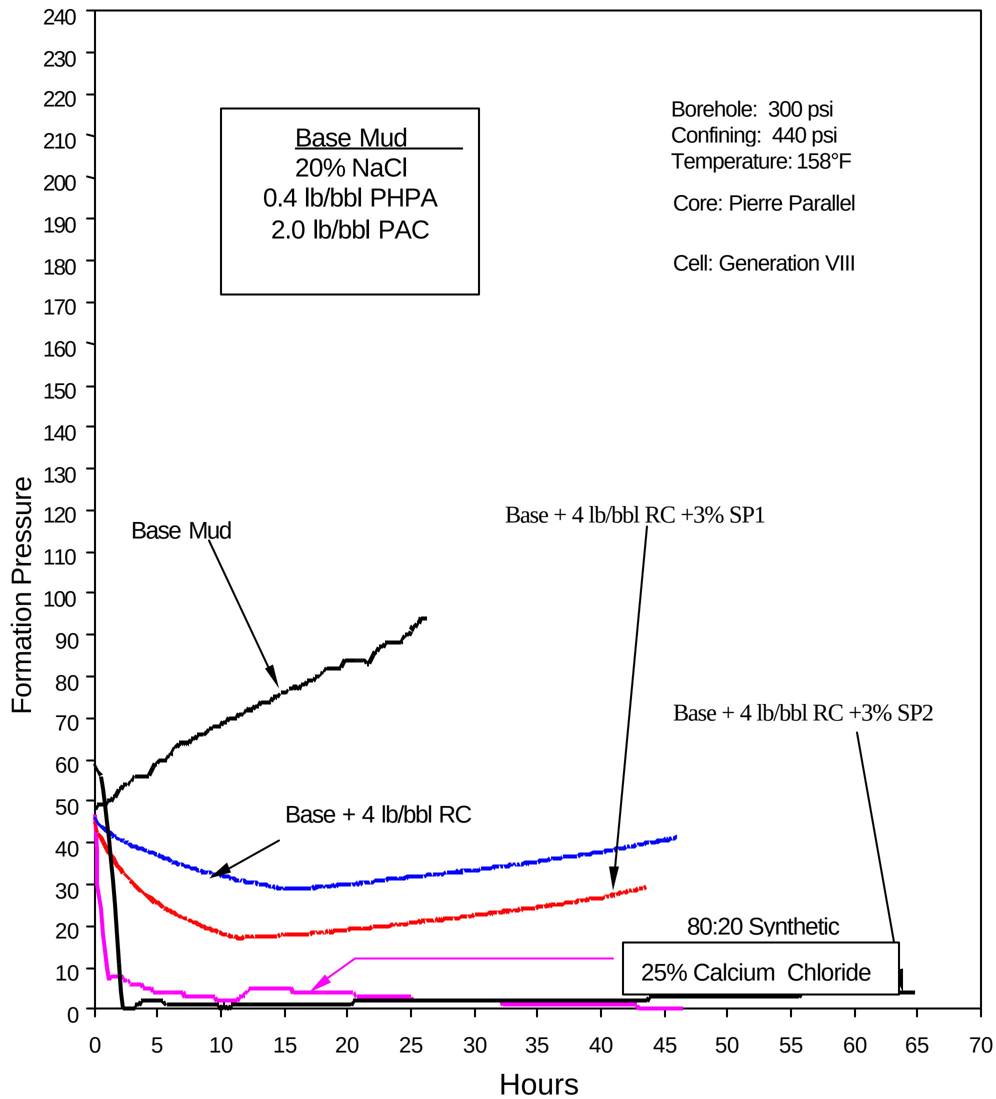

Table 1. Typical Formulation and Properties of 12 lb/gal SP/RC Mud

Formulation	
Water, bbl	0.89
Xanthan Gum, lb/bbl	0.5
Resin Complex, lb/bbl	5
PHPA, lb/bbl	1
Polysacharide, lb/bbl	4
NaCl, lb/bbl	77.5
Sealing Polymer, %	3
Barite, lb/bbl	150
Rev-Dust, lb/bbl	27
Initial Properties	
PV, cP	21
YP, lb/100 ft^2	20
10 second gel, lb/100 ft^2	4
10 minute gel, lb/100 ft^2	8
API, ml	1.4
pH	10.7
After aging for 16 hr at 250° F	
PV, cP	24
YP, lb/100 ft^2	21
10 second gel, lb/100 ft^2	5
10 minute gel, lb/100 ft^2	7
API, ml	2.6
pH	9.7
HTHP Fluid Loss @ 250° F, ml	13

Fig. 4 Sealing polymer covering shale micro-cracks.

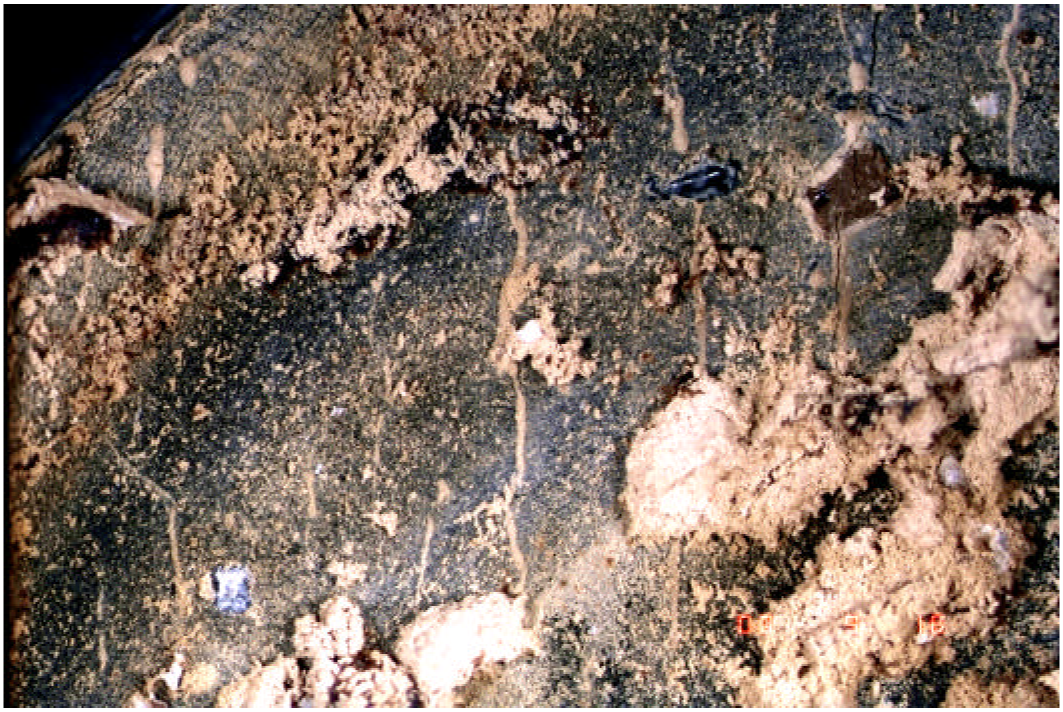

Fig. 5 Core face with sealing polymer and resin complex.

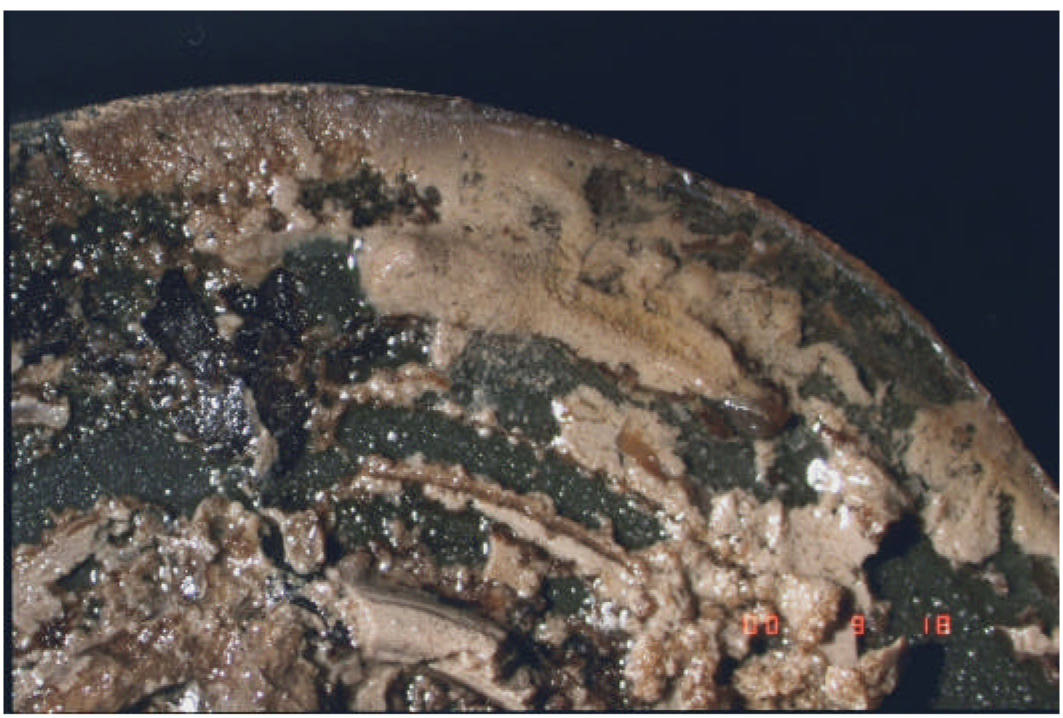

Fig. 6 Core face with another view sealing polymer & resin complex.

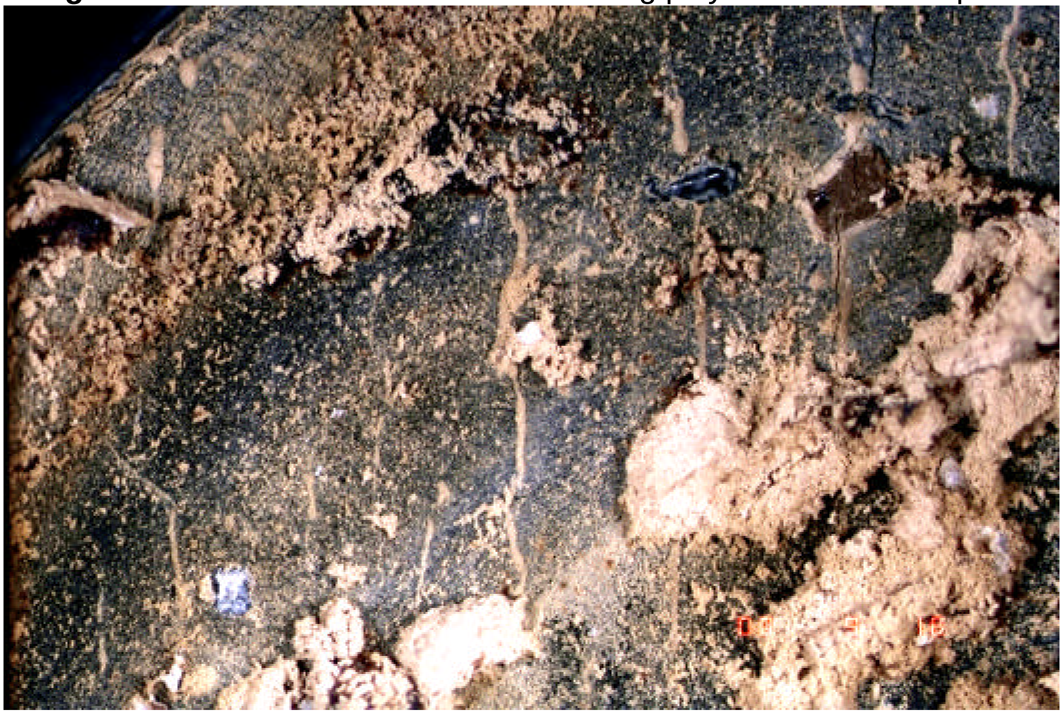

Fig. 7 Sealing poymer covering crack.

Fig. 8 Close up of resin complex

Fig 9 Thin filtrate invasion into narrow crack.