Fluid Selection Methodology Leads to Implementation of Methylglucoside Blend for Drilling Low Permeability Minehead Cardium Sandstone Gas Reservoirs Overbalanced

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ABSTRACT

Various formation damage mechanisms occurring in the Cardium sandstone have been documented. Many of these have been studied in the context of production enhancement. Recently, increasing attention is being devoted to damage in this formation from a drilling perspective. Often the damage concerns and issues incurred while drilling can be eased if perforations are expected to penetrate beyond the localized near wellbore damage. In vertical wells where casing is expected to cover the production zone, "drilling in" with a reasonably clean fluid exhibiting low API fluid loss characteristics is likely adequate in most instances. However, as horizontal wells and slotted-liner completions become more common and as operators rely on tighter, less permeable zones to increase reserves and production that are completed in a non-perforated openhole mode, the damage-while-drilling issue becomes more prevalent.

The objective of this paper is to present and discuss the methodology and testing results used in selecting a horizontal drilling fluid to be employed in the Cardium Gas reservoir at Minehead in Central Alberta. Various aspects of both the design of the fluid and its implementation are presented. The initial production results are also included.

INTRODUCTION

Some of the most difficult challenges in fluid design are perpetrated by tight, sub-irreducibly saturated, sandstone gas reservoirs. When these reservoirs are to be drilled underbalanced, the task is less daunting. However, diligence is still required. Underbalanced fluid design focuses on both fluid-fluid and fluid-rock compatibility as a contingency against unplanned periods of overbalance or against the occurrence of spontaneous counter-current imbibition[1]. When drilling overbalanced, the fluid design incorporates one additional dimension - the selection of the constituents to create an appropriate filter cake. This is to minimize the loss of whole fluid and mud filtrate into the reservoir. Because the very nature of cake deposition and bridging on pore throats and fractures denotes some degree of spurt loss associated invasion the same design diligence must be applied to the liquid phase of the overbalanced drilling fluid. The solid phase of the fluid - the bridging particles, must be soluble in some fluid when it's time to produce the well. In sandstone reservoirs, even if pore throats are plugged with a portion of insoluble drilled solids, if some soluble product is also present, bridge integrity will often be degraded so that production can begin.

The problem is that the bridging materials available today are either oil soluble, acid-soluble or water-soluble. Often (not always) these solvents are incompatible with the sandstone gas reservoir, especially if there is clay in the pore throats or if the cementation matrix is carbonaceous or if the reservoir lacks water. The problem is complicated in that many horizontal wells in formations with questionable competency are completed using a slotted liner, making any type of selective stimulation almost impossible.

Various formation damage mechanisms occurring in the Cardium Sandstone have been documented, most of them in the context of production enhancement. These include clay swelling, fines migration, paraffin deposition, scale and bacteria[2]. The design focus for this well centered on swelling clay and another mechanism - phase trapping or water blocking.

GEOLOGY AND RESERVOIR CHARACTERISTICS

The Minehead Cardium "C" gas reservoir is located in the 49-18 W5M area of Alberta and consists of a low permeability Cardium sandstone at an average depth of 2350-2400 m. Initial reservoir pressure (1986) had a value of 23670 kPa at a temperature of 75°C. Matrix Cardium quality in Minehead is very low with permeabilities (to air) ranging from 0.01 to 10 mD, but with the majority of the pay exhibiting permeabilities of less than 1 mD and porosity in the 10-14% range. The matrix consists of a moderately sorted mid to upper fine-grained quartz cemented quartzose litharinite. Primary intergranular porosity is lowered by compaction effects and cementation by authigenic quartz. Authigenic chlorite clays increase micro-porosity in some areas of the sand and reduces permeability. The chlorite coats grains and lines pore throats. In average matrix, pre diameters range from 45-65 microns and pore throat sizes from 0.6 to 7 microns. It is postulated that some degree of natural fracturing is present in Minehead in the Cardium sand which will act as a feed source from a large volume of the tight matrix. Intersection of these fractures by the proposed horizontal well was another primary objective of the program.

Previous laboratory analysis conducted on Cardium samples form this vicinity indicated the bulk rock was up to 4.3% acid soluble with traces of calcium, magnesium, iron and sulfate in the acid filtrate. An S.E.M. equipped with an energy dispersive analyzer detected kaolinite, illite, mixed layer illite / smectite and chlorite. These clays were described as being dispersed throughout the core matrix, lining pore throats and coating detrital grains. The following properties describe the reservoir at this location:

Reservoir Type	Gas
Acid Gas	Gas
Depth	2400 mTVD
Pressure (current)	17.0 mPa
Equivalent Density to Kill (current)	670 kg/m^3
Permeability (air)	0.01-10 mD
Porosity	8-14%
Average Pore Throat Size	0.7-7 μm
Temperature	75°C
Bitumen (present)	No
Fractures	Microfractures Present
Wettability	Water Wet
Swi (average)	16%

BOREHOLE STABILITY

Rio Alto Exploration Limited chose to place a horizontal wellbore into the Cardium reservoir at the Minehead field in Central Alberta. Given the geological and reservoir conditions the most cost effective drilling strategy would likely have been to drill into the reservoir underbalanced. Prior to designing the well, a borehole stability study was conducted by an independent contractor. Caliper logs from vertical wells were analyzed to identify and locate hole enlargement occurrences within and immediately above and below the Cardium Sandstone. The borehole stability model STABView was used to predict the extent of rock yielding for the most critical geological units in the planned horizontal well. Input parameters for this modeling were estimated from available geological data, reservoir data, drilling data and wireline log data provided by Rio Alto. Sensitivities of rock yielding severity to critical input parameters were investigated over a range of bottom hole pressures including underbalanced and overbalanced conditions. It was determined that the risk of borehole instability from excessive rock yielding in a weak interbedded sandstone – shale interval was high for underbalanced conditions. Therefore, the well was designed to be drilled overbalanced.

FORMATION DAMAGE ISSUES - BACKGROUND

The presence of mixed layer clay in the reservoir was a primary concern during fluid system selection. The adverse effects on permeability by the swelling, smectite component have been documented in the literature. In conventional oil production, most of the clay related problems occur in the near wellbore region, and are associated with well operations such as drilling, completion and workover[3]. Therefore, the operator solicited recommendations from selected drilling fluid suppliers with "Drill in Fluid" systems designed to inhibit the tendency of the smectitic clay to swell. An equally important issue was the possibility that invaded aqueous fluids could impose a permeability reduction due to a phenomenon termed aqueous phase trapping.

Phase trapping, sometimes called "water-blocking" may be described as a saturation hysteresis effect associated with the increase and retention of an immobile liquid phase into a porous media. This effect is exaggerated in reservoirs that have a low initial immobile liquid saturation. The result of placing additional immobile fluid into the pore system is a net reduction in permeability to the producing hydrocarbon phase. This phenomenon has been described extensively in the literature[4-7]. In fact, it was the first formation damage mechanism to be recognized[8] and, by 1952, at least 28 patents had been issued to cover water-blocking removal treatments.[9]

Fluids moving through reservoir rock must travel through pores connected by narrow channels or throats, which behave like various sized capillary tubes. Surface tension, wettability effects and tortuosity play a role in determining nature of this flow. For example, in a water-wet system, water will spontaneously displace gas or oil from the capillary or pore throat. A pressure, called the threshold pressure must be applied to displace the water back out with air or oil. Near the wellbore, where the pressure may be very low, this threshold pressure may be too great to allow for the initiation of flow back into the wellbore. The pressure required to displace fluid through a capillary is inversely proportional to the pore throat radius. In very small pore throats, up to hundreds of pounds per square inch may be required to initiate flow. Figure 1 illustrates this. Reservoir rocks may be characterized in part by their proportions or saturation of various fluids. Initial water saturation (Swi) refers to the average proportion of pore space occupied by water initially - when it is first exposed. Irreducible water saturation (Swirr) represents the water saturation that is forced to exist due to capillary mechanics. In some reservoirs Swi is lower than Swirr. This situation is conducive to aqueous phase trapping. Bennion[10] has reviewed the origin of low Swi conditions in reservoirs. They include, vaporization, changes in pore geometry, adsorption of reservoir water by anhydrous clays and minerals and irreducible saturation hysteresis effects. The Minehead Cardium sand is a classical example of an undersaturated low permeability gas reservoir (16% Swi in rock with K_{avg} <1 mD).

In multiphase flow through reservoir rocks, the flow paths of the fluids are controlled by the wettability of the rock. In a water-wet oil reservoir the water flows along the surface of the sand grains and the small capillaries while the oil flows through the center of the pores and through the larger capillaries. Figure 2 shows the permeability relationship between gas and water as a function of water saturation. Note that the introduction of water causes a marked decrease in permeability - irreversibly up to the point where Swirr is plotted (Swirr is not necessarily the point where the water becomes mobile).

Phase traps may be established in several ways[11], the most common being, physical displacement of potentially trapping fluids into the reservoir during overbalanced operations and imbibition and countercurrent imbibition, where either hydrocarbon or aqueous filtrates are imbibed into subirreducibly saturated reservoir rock. This can occur during both overbalanced and underbalanced operations.

Factors affecting the severity of the phase trapping include the magnitude of the difference between Swi and Swirr; reservoir quality (because the capillary retention forces controlling the magnitude of Swirr are inversely proportional to pore throat radii); the configuration of the relative perm curves at low liquid saturation levels (the more convex the curve, the greater the permeability reduction for a given increase in trapped liquid saturation); the depth of invasion of trapped phase since deeper invasion results in a reduced effective drawdown gradient per unit reservoir length and available drawdown pressure.

It should be noted that additional immobile filtrate does not always result in a permeability reduction because some incremental immobile fluid can be imbibed into ineffective porosity. However, permeability effects due to hysteresis do occur in most cases where initial saturations are below irreducible. This impairment can be irreversible in the absence of special stimulation procedures.

Phase trapping in natural or induced fractures is a possibility if the fracture is small enough - usually less than 10 microns - to exhibit a capillary pressure or if damage to the matrix feeding the fracture is such that the available drawdown cannot exceed the threshold pressure described previously. (Note that Darcy's law considers pressure, not threshold pressure).

In order to predict the occurrence, it is imperative to acquire accurate initial saturation values. Log evaluations of water saturations may be incorrect if not properly calibrated or if good Rw data is not available (often the case for reservoirs where the water phase is not mobile and no water saturation data are available). Cores obtained with drilling fluids may be flushed or otherwise altered. Using low invasion core techniques or sponge coring coupled with an inert fluid such as an all oil fluid or a tracer treated water-based fluid may provide the best saturation information. Bennion[5,12] has provided methodologies for predicting phase trapping with tables, graphs and equations. The basic equation can be written:

$$APT_i = 0.25\left[\log_{10}\left(k_a\right)\right] + 2.2\,(Swi) \qquad (1)$$

where:

APTi = aqueous phase trap index

K_a = uncorrected average formation air permeability (mD)

Swi = initial (not irreducible) water saturation (fraction)

Range of validity:

k_a = 0 - 5000 mD

Swi = 0 - 1.00

If the APT is $\geq$ 1.0, the formation is unlikely to exhibit significant permanent sensitivity to aqueous phase trapping. A value of between 0.80 and 1.00 means the formation may exhibit sensitivity to aqueous phase trapping, while a value of less than 0.80 suggests there is likely a significant sensitivity to aqueous phase trapping. A more rigorous evaluation of APT may consider relative permeability adjustment, invasion profile adjustment and reservoir pressure adjustment factors[5,12].

Low permeability may not always be an indicator of phase trap potential if the low permeability is the result of a low "average frequency of flow channels" rather than the size of the pore throats. This scenario can occur, particularly in carbonates, where relatively few larger pore channels can dominate the permeability for a pore system. In this case, it is possible that the capillary retention of filtrate is minimal, even though permeability is low.

The best method of validating the prediction is to perform a phase trap test on a representative core sample. Figure 3 illustrates the apparatus used for the test. To perform the test, a small core plug is restored to its original wettability and initial saturation and fluid components in a bath containing those components at temperature. The plug is mounted, overburden stresses are applied and the apparatus is raised to reservoir temperature. In the case of a water-wet gas reservoir, after the permeability to gas has been established, formation brine, often simulated, is slowly introduced to the plug until several pore volumes have passed through it. The test then remeasures the permeability to gas at several pressures including the threshold pressure where fluid movement is initiated. If, upon re-establishing the flow of gas through the plug, the original permeability is not attained, the reduction can be attributed to a phase trapping effect.

The literature reviews and discusses various methods of dealing with phase trapping after it has occurred. Penetrating the zone of damage by perforating or hydraulic fracturing is one method. Numerous removal techniques have also been attempted and documented. Most of these methods involve IFT reduction. This avenue has merit since capillary pressure is a direct linear function of the interfacial tension existing between the trapped phase and the bulk producing phase. In gas reservoirs, injection of mutual solvents such as methanol have shown to yield better gas production[13.] However, it can be difficult to use surfactants to efficiently partition across the water/gas phase boundary. In oil reservoirs, chemical surfactants[14] as well as higher alcohols have proven effective. Gaseous IFT reducing additives such as CO_2 or solvent treated CO_2 have been used successfully in some situations. Altering pore geometry with acid serves to reduce capillary pressure, increasing permeability in the near wellbore vicinity. The effects of the spent acid (i.e. additional water) may however be as adverse as the initial situation. Other water-block removal techniques may include dehydrated gas injection and heat treatment.

Where the potential for water-block exists, preventative measures may be taken. For water-blocking in gas reservoirs, air, nitrogen, or pure oil may be considered as drilling fluids. Hydrocarbon based fluid may be successful in oil reservoirs. In all overbalanced scenarios that are intended to be open-hole completions, whole fluid or filtrate loss should be minimized. A proper bridging system design and filtrate reducers are advised. Underbalanced drilling, when possible, provides a prevention alternative, although sub-irreducibly saturated zones are likely to spontaneously imbibe drilling or misting fluid into the reservoir.

FLUID SELECTION

Table 1 provides a summary of the routine air permeability and porosity measurements conducted on the plug samples selected for use in the Minehead Cardium study. All plugs were cleaned with an azeotropic mixture of chloroform and methanol prior to testing to remove any oxidized hydrocarbons or salts.

Table 2 summarizes the results of five different phase trap tests conducted on Minehead samples using formation water (base case), various concentrations of n-butanol in water (as an IFT reducing agent) and also with an oil based Cutter "D" fluid system. The results of the baseline test with formation water actually showed the most favorable results, but it was later concluded that the sampled tested had a small microfracture (see Photograph 1) which compromised the results of the test. The other samples tested all exhibited moderate to severe reductions in permeability due to phase trapping, even with the inclusion of fairly high concentrations of butanol in the test system as an IFT reducing agent.

After the phase trap test indicated there was some damage due to phase trapping and that oil-based systems did not appear to offer a significant advantage over water-based systems, the lab work centered on water-based systems that had known surface tension reducing characteristics. All of the candidate systems required a breaker treatment. The treatment for Mud 1, the MEG system, involved a displacement to a fluid carrying a cellulose specific enzyme. It was recognized that this treatment could introduce a fluid with an inefficient surface tension reducing ability to the reservoir. Therefore, a separate study was conducted to ascertain the compatibility of methanol, a known surface tension reducer on the effectiveness of the enzyme treatment package.

This study measured the efficiency of the breaker treatment by measuring the time taken for a volume of 2% KCl water to flow through Bandera Sandstone disks before and after the disks were exposed - first to the drilling fluid, then to the enzyme treatment. The tests, summarized in Table 3 indicted that the addition of methanol to the carrying fluid did adversely affect the enzyme performance.

The mud systems tested as a portion of this work included:

Oil Based Mud 1: Gelled oil and breaker: distillate base oil-viscosified chemically as opposed to viscosification with clay. The viscosity of this system as well as the cake may be broken chemically.

Oil Based Mud 2: Gelled diesel and breaker, similar to above using diesel as the base oil.

Oil Based Mud 3: Diesel/surfactant blend.

Water Based Mud 1: System that incorporates a blend of methylglucoside and polyglisseride additives with enzyme breaker.

Water Based Mud 2: Blend of cross-linked polymers and clay stabilizer with enzyme breaker.

Water Based Mud 3: Acid soluble system that uses a proprietary surfactant with oxidant breaker.

Water Based Mud 4: Acid soluble system consisting of HEC, Xanvis, Starch, a proprietary surfactant and a proprietary clay stabilizer with "crystalline" breaker.

A total of 12 different whole mud leakoff tests were conducted on samples of restored state Minehead core material at reservoir conditions to attempt to ascertain which system provided the best regain permeability performance. A schematic of the experimental equipment used for these studies appears as Figure 4. The core sample, which had an initial water saturation of 16% uniformly dispersed within it, is mounted in a uniaxially confined coreholder that applied reservoir confining overburden pressure (43000 kPa) to the core material. The confined sample is then heated to the reservoir temperature of 75°C and baseline permeability measurements with humidified gas are conducted in a flow direction opposite to the subsequent drilling fluid invasion.

Drilling fluid, prepared by the respective fluid supplier, is added to a high-pressure continuously stirred reactor vessel. In addition, 3% by mass of synthetic drill solids, consisting of pulverized Minehead Cardium core material (to simulate those cuttings generated by the drill bit and not removed by the surface solids control equipment) are added to the mud to provide the best possible representation of the fluid which will be circulating downhole at the time of drilling. The stirred reactor keeps all solids in a state of continual suspension to ensure that a uniform mixture is flowing by the face of the core sample on a continual basis.

Due to the highly pressure depleted condition of the Cardium sand in the Minehead reservoir (currently approx. 14000 kPa), high overbalance pressures are expected to be encountered when using conventional oil or water based drilling fluids. The specific overbalance pressure for each mud tested was calculated based on that fluids specific and total overbalance pressured varied between 9000 to as high as 14000 kPa depending on the system under consideration. Whole mud, at the specified overbalance pressure, is displaced past the face of the core sample on a continuous basis until either a steady state leakoff or sealing filter cake is established and the total fluid losses and depth of invasion of filtrate are tracked. Following this procedure a breaker treatment was applied, with sufficient time for reaction to occur, for many of the tests. Regain permeability measurements to gas were then conducted (in the opposite direction to the mud exposure to simulate production from the reservoir after drilling) by gradually increasing the drawdown pressure in incrementals up to the maximum value expected to be attainable in the reservoir. This was conducted while tracking the increase in permeability at each level to ascertain the minimum threshold pressure for gas flow initiation into the damaged matrix and determine the degree of permeability impairment as a function of the degree of increasing drawdown.

The results of the two series of experiments are summarized in Tables 4 and 5. The test results clearly indicated that the water-based Muds #1 and #2 had the best performance of the mud systems tested. Subsequent to this, it was ascertained that a portion of this favorable regain perm was due, once again, to the presence of a microscopic fracture in the core samples (visible only under a high magnification SEM examination). Although it was felt that this had contributed to the good performance of the MEG system, it was determined that, due to the small aperture of the fracture, some benefit was likely still apparent in comparison to the other system tested which had less favorable performance, and that the presence of small fractures such as this were, in fact, representative of the target type of matrix in the Cardium sand in Minehead. More detailed studies using variants of the MEG system are summarized in Table 5. The results suggested that high concentrations of methanol degraded the performance of the breaker system. Based on this, a 12-14% MEG system with no methanol was selected as the optimum fluid to drill the well.

MEG THEORY

Alkyl glucosides are members of the class of compounds known generically as glycosides. The term glycoside is applied to a compound where a sugar is combined through its reducing group with an organic substance such as a phenol. Many of the known glycosides occur naturally in plants and animals and were originally isolated from such sources. The sugar portion of most naturally occurring glycosides is glucose and accordingly, these glycosides are known specifically as glucosides. The product that was used in this project is manufactured from cornstarch. It has desirable qualities including lower viscosity, temperature stability, and bacterial resistance. Thermographic analysis showed stability to about 350° F in a nitrogen atmosphere for a 70% w/w solution. A

65% w/w solution of methylglucoside remained fluid at -22° F. A 40% w/w solution of methylglucoside showed no growth of microorganisms even when inoculated with bacteria, mold or yeast. Simpson et al[15] attested to the superior lubricity coefficient of the system. The fluid used in their Downhole Simulation Cell (DSC) test had a lubricity coefficient of 0.06 as tested by the API RP-13B procedure. Water-based fluids typically have a coefficient of 0.2 to 0.3 while oil-based systems usually have coefficients of less than 1.

The product referred to in this paper is from a commercial product that is about an equal mixture of the alpha and beta forms to which KOH has been added to provide an alkaline solution containing 70% w/w methylglucoside. This solution has in turn been complimented with an additional product, Polyglycerine that has proven to be synergistic in terms of inhibiting clay hydration. The properties of the final product, called NDFX 119°C are outlined in Table 5.

The primary function of NDFX 119C is to provide shale hydration. Simpson has suggested that the methylglucoside solute becomes fixed in the near borehole surface of the shale. This establishes an effective semi permeable membrane that allows the solvent (water) to move from the shale to the mud under a chemical (osmotic) potential that exceeds the hydraulic potential tending to force water into the shale. The study indicated that 44% w/w of the neat product had a vapor activity of 0.88.

Liquid chromatography analysis of the shale from Downhole Simulation Cell (DSC) tests conducted in Simpson's study provided confirmation of the fixing of the methylglucoside onto the shale. Shale sampled within 0.25 inches of the test borehole contained 1.4% w/w methylglucoside while no methylglucoside was detected deeper into the core. The study suggested that the presence of the hydroxyl groups in the methylglucoside configuration might account for the unique ability to form a semi permeable membrane just inside the shale. The hydrated monomer seems to be the right size to penetrate the exposed pore spaces where interaction with the clay surfaces cause the methylglucoside to become fixed, while the water solvent remains free to move. Hydrogen bonding was suggested as a possible method of fixation. Testing also showed that shale exposed to this system remained intact and was actually harder in the vicinity of the simulated well bore that was tested.

Yan Zhang et al[16] evaluated several characteristics of methylglucoside as they related to sandstone reservoir damage. They found the methylglucoside system was less damaging than other drilling fluid systems it was compared to. The study concluded that the adsorption of the methylglucoside hydroxyl onto the clay surfaces prevented both clay swelling and clay migration. They also postulated that the tight filter cake and "excellent" filtration properties could be attributed to the same mechanism. The hydroxyl group assisted particles in adsorbing onto surfaces, promoting a tight cake. Photograph 2 shows a SEM photograph of the methylglucoside system filter cake against one of the Cardium Sandstone core plugs used in fluid selection for the Rio Alto well. The Zhang study also concluded that the methylglucoside fluid was also effective in reducing damage caused by filtrate retention due to its low surface and interfacial tension.

HSE ISSUES

The National Institute for Safety and Health (NIOSH) and the Occupational Safety and Health Administration U.S. Department of Labor (OSHA) do not list either Polyglycerine or Methylglucoside in their databases. The Workplace Hazardous Materials Information System (WHMIS) classification is "D-2(B)" meaning it can be a skin and eye irritant, and the Transportation of Dangerous (TGD) classification is "Not applicable".

The two components of the NDFX 119C inhibitor are relatively non-toxic to most test species however, surfactants do not fair well in the Microtox bioassay. The Microtox test uses bioluminescent bacteria as the test species and these organisms are sensitive to surfactants. A review of the toxicity to various species is included in Table 6.

Biodegradability tests conducted at the University of Calgary indicate that NDFX 119C is readily biodegradable. Toxicity tests on soil/waste combinations show that the material is readily absorbed by soils and that it can be biodegraded rapidly.

Application of the wastes to a biologically active soil is the best way to biodegrade the active components of the whole mud system. This will remove any Microtox test determined toxicity from the wastes and they will be able to be disposed of by routine methods. There are two scenarios for the disposal of the wastes. For disposal of solids, samples of the solids and waste are combined in a few ratios and an aqueous extract is taken from each of the mixtures. Depending on the toxicity of the extracts, the solids may be mixed, buried and covered or be spread on lease and allowed to biodegrade. Research has shown that typical field ratios of soil and waste are usually non-toxic. If the whole fluid needs to be disposed the best and most economic alternative is to pump-off the liquids adjacent to the lease and dispose of the solids as above. During winter operations there are significant issues with respect to freezing which may render this option impractical. The results in Table 6 were submitted to the EUB and the disposal methods were discussed. It was agreed that approvals for the disposal of this system would be granted on a site-to-site basis.

FIELD IMPLEMENTATION

The well was designed as a new drill, to be drilled from a location at 01-07-49-17 W5M in Central Alberta. Ensign

Drilling Rig 33E was chosen to drill the well. This is a rotary rig equipped with a Mid-Continent U-36EA (500HP / 373kW) draw works. After drilling 349.0mm hole in one pass using a Bentonite slurry, 244.5mm casing was set at 600m. 222mm intermediate hole was drilled with an all oil fluid to kick off point at 2425m, where angle building continued to 90^0. 177.8mm casing was set at 2621mMD – 2414TVD. The 156mm horizontal hole was programmed to use the NDFX 119 fluid. The inclination remained at approximately 90°, while drilling proceeded through the Cardium formation to a total depth of 3539mMD. The open horizontal displacement totaled 918m. Upon completion of drilling, a 144mm liner was set in the open-hole horizontal interval.

The drilling fluid contained 12% v/v NDFX 119 initially. Table 7 shows the chemical constituents of the drilling fluid system. Table 8 shows the fluid properties that were typical of the interval. After drilling commenced, fresh water was added to the system in $5m^3$ increments to maintain volume. 3 barrels of NDFX 119 were added with each $5m^3$ of water. The NDFX 119 concentration was monitored at the well site during drilling. It was increased to 14v/v% at 2900mMD, to improve the sliding ROP. This addition helped but it also was associated with a minor viscosity increase. All bit trips and pipe movement were reported as "good" until 3307mMD, where it was necessary to ream and clean through the lateral section, with bit #6B to 3307 m. Drilling continued with the rheology being increased to improve hole cleaning as well as the sliding ROP. At total depth, directional tools were laid down and the hole was wiped with a slick string. The well was not displaced to the enzyme treatment, as it was felt that breaking the fluid viscosity as well as the filter cake could contribute to a loss of borehole integrity and thereby jeopardize the success of the liner running operation. The 114 mm slotted liner was lowered to total depth without problems. The liner was not cemented into place.

PRODUCTION

Production in the Minehead Cardium Pool (C and F) commenced in late 1986. Initial pool pressure was 23670 kPa. Currently, the pool pressure varies with location and permeability. Pool pressure in the vicinity of the 01-7 well was estimated to be in the vicinity of 15000 kPa to 17000 kPa. A static gradient taken before commencement of production indicated the pressure was 14260 kPa. Well production commenced at approximately 150 $10^3m^3/d$ (5.3 MMscf/d) and has declined over three months to 80 $10^3m^3/d$ (2.8 MMscf/d). This rate is approximately twice the flow rate of a fractured vertical well. Cost of the horizontal well is about twice that of a fractured vertical well. The incremental economic benefit is currently being assessed.

CONCLUSION

A methodology for the selection of a low damage overbalanced drilling fluid system for a clay containing low permeability sandstone has been presented. Major damage mechanisms found to be operative in the Cardium sand in the Minehead reservoir included possible fresh water induced clay damage and severe potential for water and hydrocarbon phase trapping. Accordingly, the best fluid system, with respect to clay stabilization, fluid loss and IFT and regain permeability properties for phase trapping, was found to be a methylglucidside based water base system. This system was successfully used to drill a 965 m horizontal well in the highly depleted microfractured Minehead Cardium sand at approx. 13000 kPa overbalance with no significant fluid losses and good inflow performance in excess of 5,000,000 scf/day from the very low quality (<0.5 mD) matrix.

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Table 1. Routine Core Analysis on Small Diameter Test Plugs

Sample No.	Depth (m)	Perm (mD)	Porosity (Fraction)	Grain Density (kg/m^3)
Minehead 8-27-49-18 W5M				
15A	2360.72 - 61.11	0.990	0.147	2640
15B	2360.72 - 61.11	0.780	0.141	2640
26B	2364.11 - 64.31	0.640	0.129	2650
9A	2358.96 - 59.29	0.460	0.150	2680
14A	2360.42 - 60.72	0.400	0.129	2640
9B	2358.96 - 59.29	0.300	0.138	2680
10C	2359.29 - 59.74	0.300	0.140	2660
10A	2359.29 - 59.74	0.280	0.139	2660
10B	2359.29 - 59.74	0.280	0.139	2660
23	2363.21 - 63.54	0.270	0.134	2660
14B	2360.42 - 60.72	0.250	0.122	2640
26A	2364.11 - 64.31	0.090	0.083	2650
Minehead 11-13-49-18 W5M				
11	2382.97 - 83.25	0.620	0.121	2650
12	2383.25 - 83.57	0.620	0.118	2630
13	2383.57 - 83.83	0.580	0.107	2650
20A	2385.15 - 85.46	0.240	0.105	2650
20B	2385.15 - 85.46	0.230	0.110	2650
14	2383.83 - 84.09	0.200	0.099	2630
24	2386.23 - 86.53	0.060	0.083	2650

Table 2. Results of Phase Trap Tests

Core No.	Trapping Fluid	Initial Gas Perm @ 16% Swi	Regain Perm to Gas @ Drawdown Pressures (kPa)				
			621	1931	4451	6757	10432
20A	5% Butanol	0.036				0.004	0.007
20A	7% Butanol	0.036				0.005	0.008
20A	10% Butanol	0.036				0.003	0.006
15A	Cutter “D”	0.441				0.097	0.111
15B	Form H_2O		0.052	0.101	0.224		0.247

Table 3. Enzyme Treatment Test Results

System	Test	% Methanol added to Breaker Blend	Initial Time (s) for 250 ml to pass	Final Time (s) for 250 ml to pass	% of original
2%KCL with Enzyme Breaker Blend	1	0	107.2	181.0	59.2
	2	10	154.7	319.6	48.4
	3	20	77.0	326.0	23.6
	4	20	121.0	436.0	27.8
Blank - no Enzyme	5	0	85.0	542.0	15.7

Table 4. Summary of Results from Whole Mud System Leakoff Tests

Core No.	Mud Constituents	Initial Gas Perm @ Swi	Regain Gas Perms @ kPa Drawdown (mD)			
			965	**3585**	**7860**	**13790**
10B	OB Mud #2	0.053	0 (0)	0 (0)	0.002 (3)	0.002 (3)
10A	OB Mud #1	0.017	0 (0)	0 (0)	0.002 (12)	0.003 (20)
14B	WB Mud #3	0.055	0 (0)	0.010 (19)	0.014 (26)	0.022 (41)
11	OB Mud #3	0.193	0.048 (25)	0.060 (31)	0.073 (38)	0.096 (50)
12	WB Mud #1	0.164	0.045 (27)	0.070 (43)	0.133 (81)	0.164 (100)
14A	WB Mud #2	0.076	0 (0)	0.633 (43)	0.057 (74)	0.075 (98)

Table 5. NDFX 119°C Properties

Boiling Point °C:	>93	Color:	Dark Brown
Flash Pt PMCC – neat	>149°C	Viscosity:	90-110 cps (600 rpm – at 50°C)
Specific Gravity:	1.260-1.300	PH	10-11
Vapor Pressure:	<4 (MM HG)	Appearance:	viscous liquid
Solubility In Water:	Miscible	PH:	10.0 – 11.0
LC50	218,000 ppm	Surface Tension at 25°C	47.4 dynes/cm

Table 5. Summary of Results from Whole Mud System Leakoff Tests

Core No.	Mud Constituents	Initial Gas Perm @ Swi	Regain Gas Perms @ kPa Drawdown (mD) [% regain of original]			
			965	2689	5378	10432
9B	WB Mud #2 10% Deepdrill (MEG) 20% MeOH Mudzyme "C" Breaker "X"	0.115	0 (0)	0.006 (5)	0.014 (12)	0.022 (19)
10C	WB Mud #1 10% Deepdrill (MEG) Xanvis 20% MeOH Mudzyme "C" Breaker "X"	0.058	0 (0)	0.011 (19)	0.016 (27)	0.020 (35)
23	WB Mud #4	0.058	0 (0)	0.016 (28)	0.022 (38)	0.026 (46)
26B	WB Mud #1 10% Deepdrill (MEG) Mudzyme "C"	0.262	0 (0)	0.003 (1)	0.003 (1)	0.009 (3)
9A	WB Mud #1 10% Deepdrill (MEG) 10% MeOH Mudzyme "C" Breaker "X"	0.153	0.028 (18)	0.064 (42)	0.077 (50)	0.083 (54)
13	WB Mud #1 20% Deepdrill (MEG) Mudzyme "C"	0.073	0 (0)	0.010 (14)	0.025 (34)	0.031 (43)

Table 6. Toxicity Summary for NDFX 119

	Bioassay	Data	Interpretation
1	Mysid Shrimp (neat NDFX 119)	218,000 ppm	Pass
2	Mysid Shrimp (Mud - 30% NDFX 119)	541,000 ppm	Pass
3	Trout (Mud – 10% NDFX 119)	176,800 ppm	Pass
4	Microtox (6% Polyglycerine)	EC50 – 2.0	Toxic
5	Microtox (4% Methylglucoside)	EC40 – 4.2	Toxic
6	Microtox (Mud – 10% NDFX 119)	EC50 – 2.0	Toxic
7	Microtox (5% Mud/soil – initial)	EC50 – 64.1	Moderate Toxicity
8	Microtox (10%Mud/soil – initial)	EC50 – 61.6	Moderate Toxicity
9	Microtox (20% Mud/soil – initial)	EC50 – 82.7	Slightly Toxic
10	Microtox (5% Mud/soil – final)	EC50 – 100	Non-toxic
11	Microtox (10% Mud/soil – final)	EC50 – 96.4	Non-toxic
12	Microtox (20% Mud/soil – final)	EC50 – 100	Non-toxic

Mud is simulated field mud with all additives present.
Soil is from an Alberta drilling location – 1:4 extract

Table 7. Chemical Constituents of the Drilling Fluid System

Name	Concentration (kg/M^3)
Xanvis	0.8
Drispac	2.2
Bacteriacide	0.5
NDFX 119	12 – 14%v/v

Table 8. Typical Drilling Fluid Properties

Funnel Viscosity – s/l	45-75	K – Poise	1.4-2.4
Density – kg/m^3	1030-1100	Gel 0 - Pa	2.5-4.0
pH	9-10.5	Gel 10 - Pa	3.0-7.0
Yield Point – pa	10-26	MBT - kg/m^3	N/A
Plastic Viscosity – mPa	11-28	API Fluid Loss – cc's	5.2-8.0
n	0.34-0.48	Cake - mm	0.5

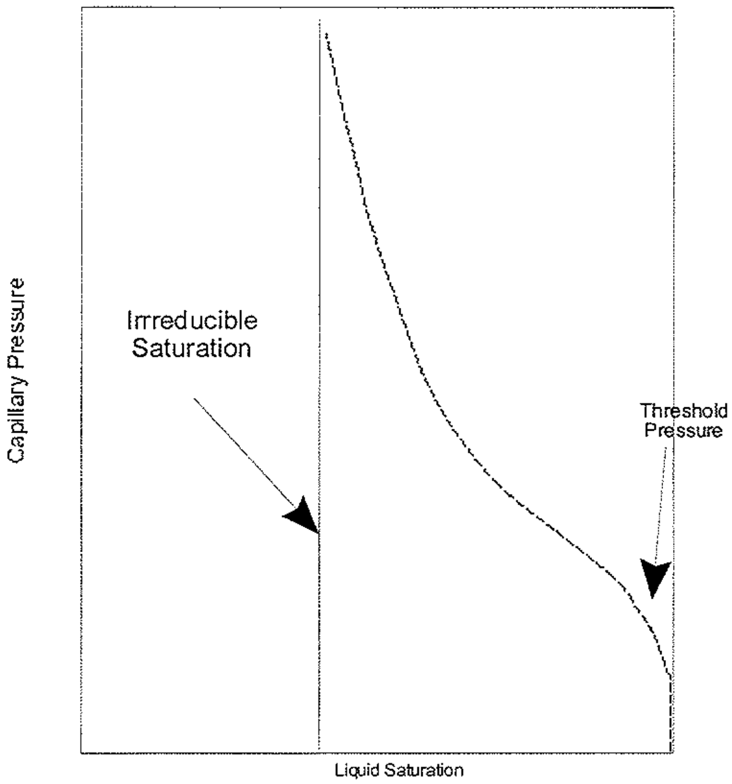

Figure 1. Illustration of Capillary Pressure Effects on Threshold Pressure and Irreducible Water Saturation

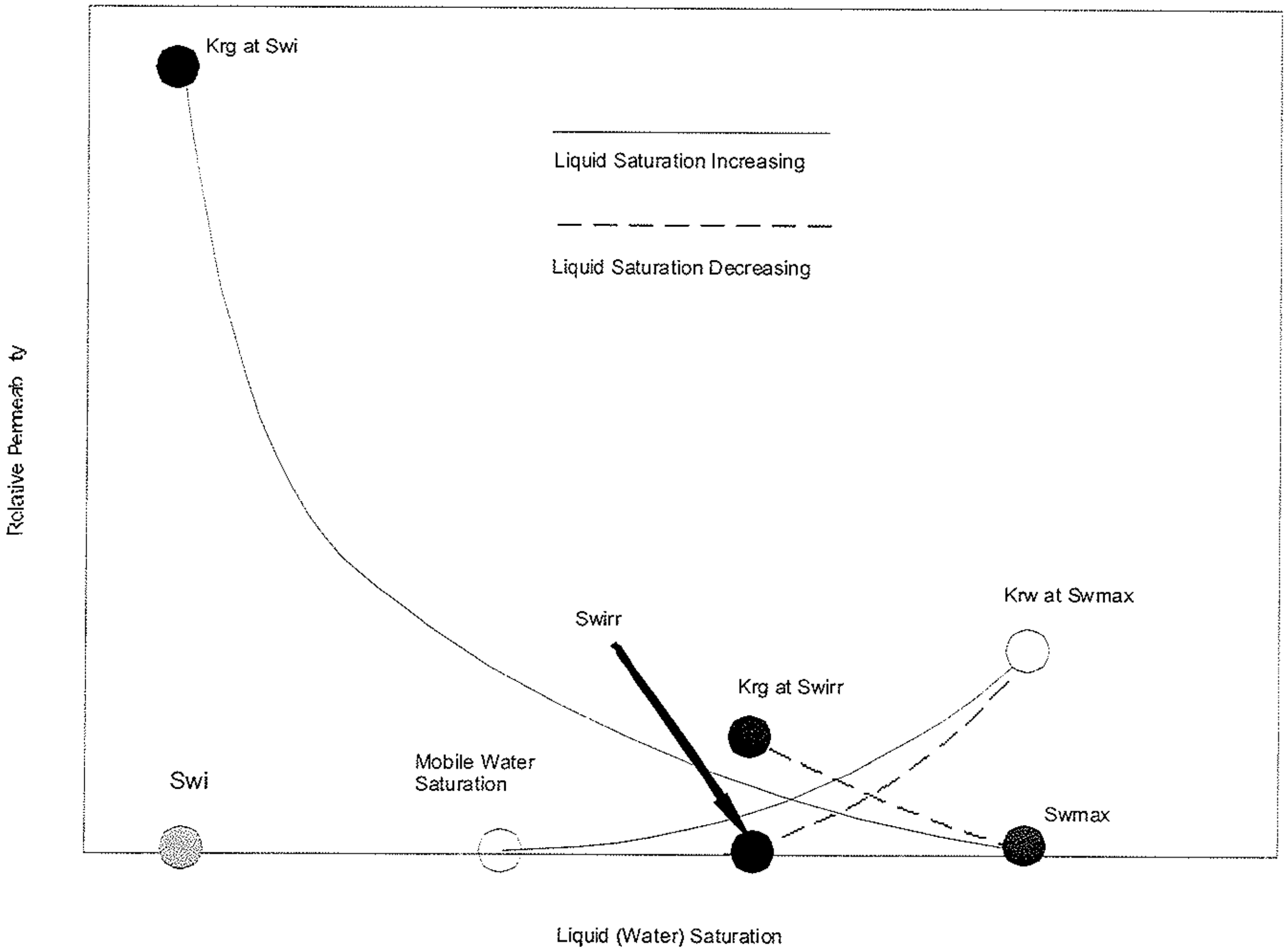

Figure 2 - Illustration of Phase Trapping Effects Using Relative Permeability Curves

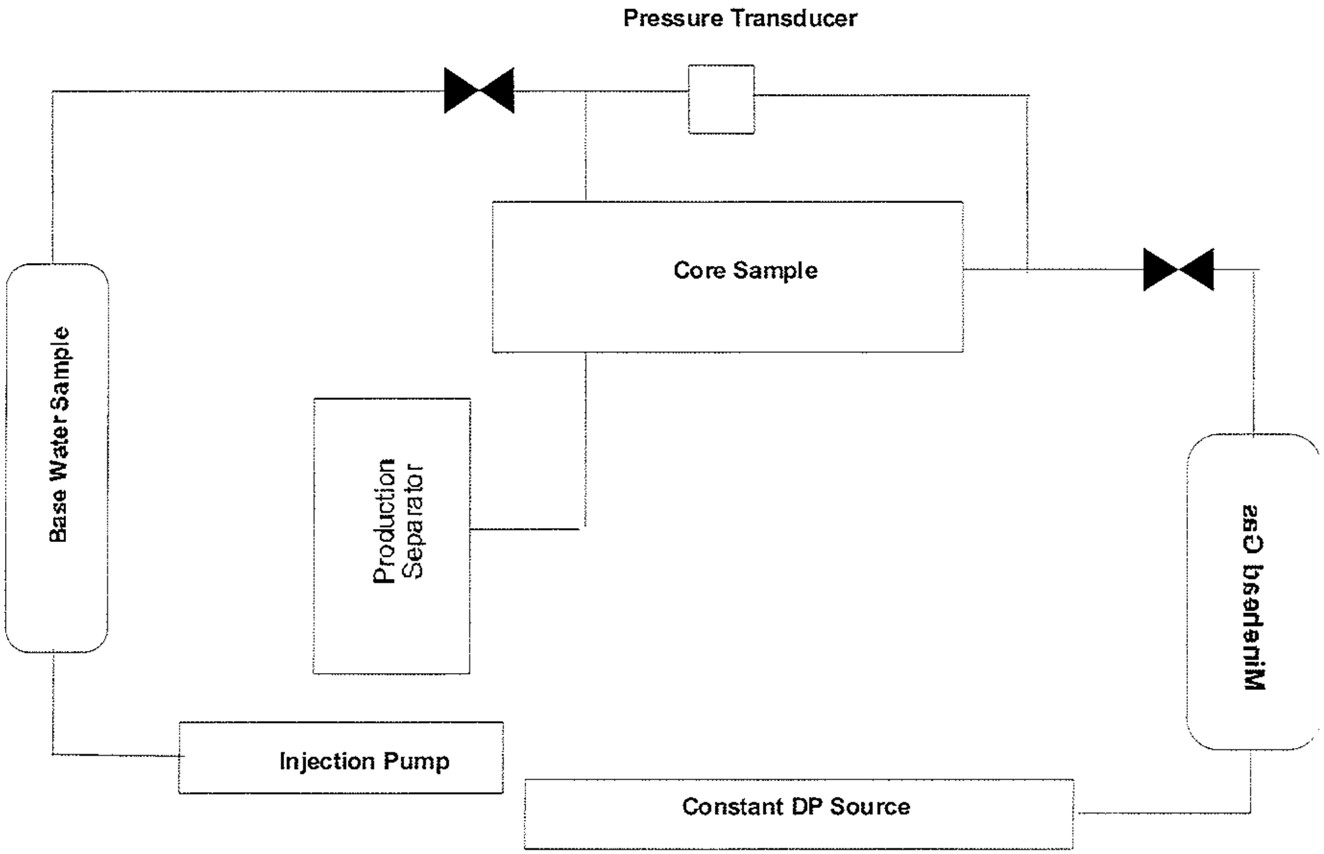

Figure 3 - Phase Trap Apparatus

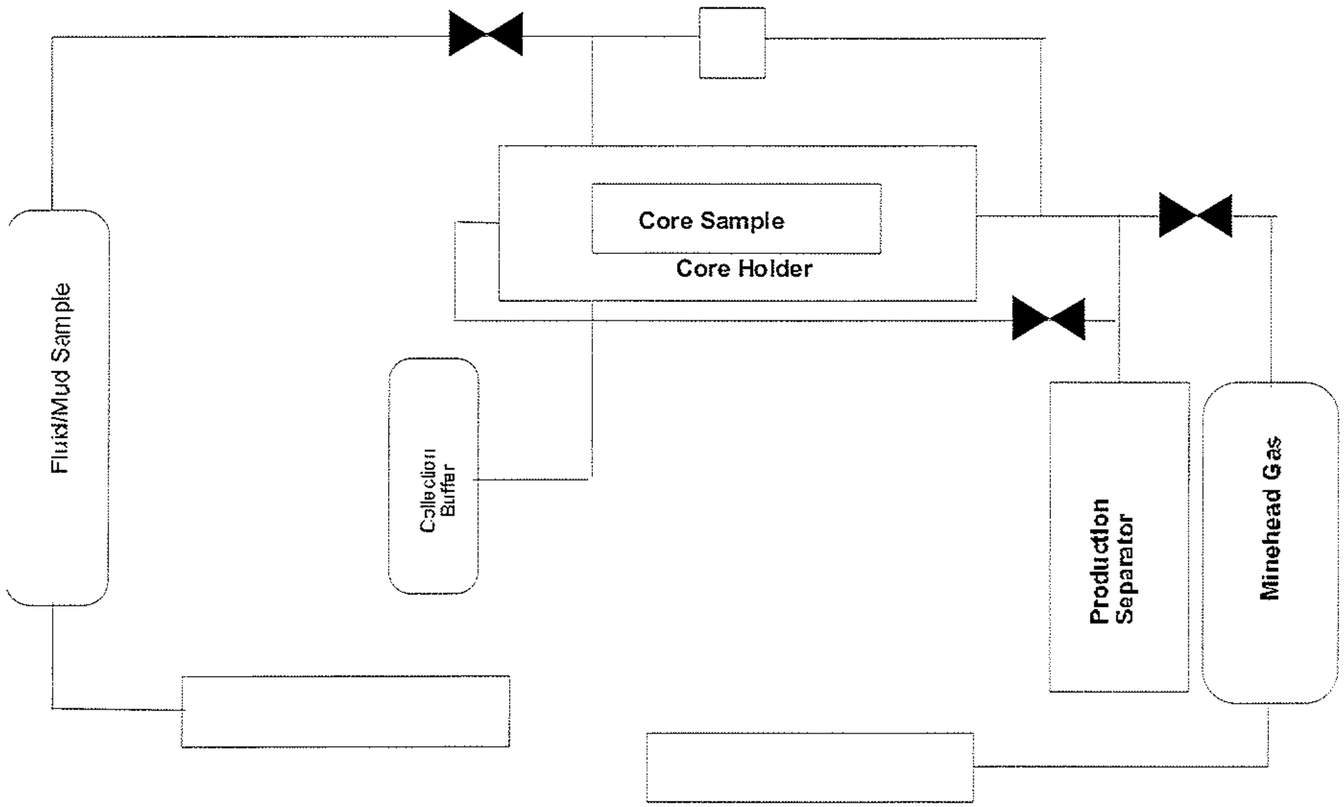

Figure 4 - Drilling Fluid Leakoff Apparatus