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Enhanced Well Productivity Potential from a New High-Density Reservoir Drilling Fluid

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Abstract

A new reservoir drilling fluid system utilizes a non-biopolymer, acid- or enzyme-soluble polymer that serves both as viscosifier and fluid-loss additive when combined with activated magnesium oxide and a divalent-cation-based brine. The fluid shows a unique shear-thinning rheological profile featuring relatively low, high-shear-rate viscosity along with relatively high, low-shear-rate viscosity. As a result, effective hole cleaning is provided without generating excessive high-shear-rate viscosities that lead to disproportionate equivalent circulating densities. The new fluid system is based on the higher density, divalent-cation-containing brines (utilizing $CaCl_2$, $CaBr_2$, $CaCl_2$ / $CaBr_2$, $ZnBr_2$ / $CaBr_2$ and $ZnBr_2$ / $CaBr_2$ / $CaCl_2$) in the 11.5 to 17.5 lb/gal density range. The total amount of the sized $CaCO_3$ bridging particles is kept relatively low, 13 to 35 lb/bbl, so that thin, chemically removable filter cakes are produced. This bridging particle matrix size distribution is designed according to the ideal packing sequence for optimizing sealing and producing a minimally invading (well productivity enhancing) fluid.

Introduction

A number of technical advances in the petroleum industry have created cost-effective methods for the exploration and development of deep oil and gas reservoirs. One result of these developments is an increased demand for higher density reservoir drilling fluids (RDF’s). However, the density attainable for economically viable, brine-based RDF’s is limited under current technology.[1,2,3,4] Some limitations are based on the fact that current biopolymer-$CaCO_3$-brine based RDF’s utilize viscosifiers that are either incompatible with the higher-density brines or require special mixing equipment and/or techniques and complex formulations.[1,2] In other cases, the cost of a base brine compatible with currently available biopolymer viscosifiers is such that the final drill-in fluid is priced out of consideration.[4,5] This paper presents a newly developed biopolymer-free RDF that uses conventional high-density base brines to fulfill the density requirement, a low concentration of bridging-solids, and a new viscosifier / fluid-loss package to produce an easily blended drill-in fluid with exceptional rheological and filter cake qualities.

Most brine-based reservoir drilling fluid systems used today consist of five primary components: base brine, pH-control additive, biopolymer-derived viscosifier, starch-based fluid-loss additive, and bridging particles.[5,6] Containing no biopolymers, such as xanthan[7,8] gum or scleroglucan,[9] the new non-biopolymer reservoir drilling fluid (NBRDF) system uses a single non-biopolymer, acid- or enzyme-soluble starch that fulfills the role of both viscosifier and fluid-loss additive when combined with a divalent-cation-based brine and a highly activated magnesium oxide. This fluid delivers a unique shear-thinning rheological profile that provides effective hole cleaning without generating excessive high-shear-rate viscosities that lead to disproportionate equivalent circulating densities.[10,11]

The new NBRDF system is based on the higher density, divalent-cation-containing brines in the 11.5 lb/gal to 17.5 lb/gal density range. The fourth and final primary component of the new NBRDF system is the matrix of sized $CaCO_3$ particles, the total amount of which is kept relatively low, 13 to 35 lb/bbl, so that thin (**Fig. 1**), lubricious, and easily removed filter cakes (**Fig. 2**) are produced. The size distribution making up this matrix of $CaCO_3$ particles is designed according to the ideal packing sequence for optimizing sealing. This approach is designed to minimize formation damage by forming a thin, ultra-low permeability and high durability filter cake on the face of the formation, thereby minimizing fluid and solids invasion into the formation.[6,12,13,14,15]. As will be seen in the tables to be discussed below, extensive laboratory fluid loss testing consistently shows low filtrates.

The new NBRDF system tolerates contamination with drill solids and cement, with enhancement in rheological properties, especially at low shear. The NBRDF system is inherently inhibitive toward shales, but if there is a desire to build in additional shale inhibitors, the new fluid system is highly tolerant toward additional inhibitors.

This paper highlights the unique rheological properties and excellent filtercake qualities that result from the easily blended biopolymer-free drill-in fluid formulation. These and other qualities of this new NBRDF are further detailed in an upcoming publication.[16] Field application of this new NBRDF began in the Norwegian sector of the North Sea. Details of this case history are provided in another upcoming publication.[17]

Stable Rheologies

Table 1 provides a summary of the properties for the new non-biopolymer reservoir drilling fluid system. Details are provided in **Tables 2-6**:

Table Number	Density (lb/gal)	Temp (°F)	Total Heat Aging (hr)
2	11.5	185	16
	14.5	235	16
3	14.0	200	60
	16.5	185	16
4	11.4	200-250	16
	11.75	200-250	16
5	12.5	200-250	16
	14.0	210-260	16
6	12.5	235	18
	13.5	235	18

The data in **Tables 2-6** show that the new NBRDF system provides stable rheologies over a wide range of conditions, including relatively high, low-shear-rate viscosities that provide good particle suspension for excellent hole cleaning over a broad range of conditions.

This feature of the relatively high, low-shear-rate viscosities evident in **Tables 2-6** is a significant point of departure between the new non-biopolymer RDF system and conventional $CaCO_3$-biopolymer-based RDF's in high calcium or zinc brines. Most other brine-based RDF's incorporate both a starch and a biopolymer like xanthan or scleroglucan. Most of the fluid's viscosity is only achieved when the biopolymer is fully yielded; therefore, the biopolymer is termed a viscosifier. The starch is termed a fluid-loss additive inasmuch as the formulations without starch seldom have more than marginal fluid-loss-control character.

The new NBRDF system relies solely on the fluid-loss additive to serve both roles of viscosifier and fluid-loss-control agent. This is why the unique highly modified starch in the new NBRDF system is referred to as a dual function starch (DFS). This characteristic alone distinguishes DFS as an unusual starch. DFS performs well in brines based on $CaCl_2$, $CaBr_2$, $CaCl_2$ / $CaBr_2$, $ZnBr_2$ / $CaBr_2$ and $ZnBr_2$ / $CaBr_2$ / $CaCl_2$; but in seawater, NaCl-based, and NaBr-based brines, DFS does not exhibit much capability as a viscosifier.

The new NBRDF system is not intolerant of the addition of monovalent cation salts, like NaCl and NaBr, as long as the addition does not dilute the divalent cation concentration below about 6 to 10 wt %. Therefore, little or no difficulty is anticipated in drilling through salt.

In lower densities and even as high as 14.0 lb/gal (**Table 7**), higher low-shear-rate viscosities are consistently developed with the addition of small increments of a highly reactive magnesium oxide (HRMgO), a pH-control agent. The suggestion that a pH-control additive could be contributing viscosity is quite surprising, especially when it is noted that adding HRMgO tends especially to enhance the fluid's apparent viscosity at 0.0636 sec^{-1} shear rate (LSRV), while having minimal effect on the fluid's viscosity at higher shear rates (**Table 7**).

A further distinction between the viscosifying characteristics of the new NBRDF and conventional RDF's is the ratio $LSRV/AV_{600}$. The commonly used parameter AV_{600} is the apparent viscosity measured on the Fann 35 at 600 rpm, *i. e.*, at the relatively high shear rate of 1022 sec^{-1}. The $LSRV/AV_{600}$ ratio is sometimes referred to as the shear-thinning index. This parameter is dimensionless because both AV_{600} and LSRV are measured in the same units (cP). A desirable RDF viscosity profile would be to have a high value of LSRV and a low value of AV_{600}. High LSRV gives good drill solids suspension and hole-cleaning character. Low AV_{600} permits low pressure losses in the drill pipe. The result of these low pressure losses is the transmission of as much of the hydraulic energy in the pumped fluid to the drill bit as possible without running the risk of hydraulically fracturing the formation. These considerations suggest that high $LSRV/AV_{600}$ ratios are desirable in RDF's.

The $LSRV/AV_{600}$ ratio is typically higher – often 2 to 3 times higher – for the new NBRDF than for conventionally viscosified brine-based RDF's in high calcium or zinc environments. $LSRV/AV_{600}$ drops with increasing density in the 14- to 17.5-lb/gal range; however, the drop is significantly less for the new NBRDF than for conventionally viscosified brine-based RDF's. In fact, in the 15.5- to 17.5-lb/gal range, $LSRV/AV_{600}$ drops to essentially zero for conventionally viscosified brine-based RDF's – the biopolymer shows only limited ability to develop LSRV in high-salt, zinc-containing brines.

As shown in **Table 8**, the new NBRDF system at 14.0 lb/gal develops substantial LSRV; while a 14.0 lb/gal

$CaCO_3$-biopolymer RDF, substantially less. At the same time, the new NBRDF system develops only a moderate AV_{600}, while the 14.0-lb/gal $CaCO_3$-biopolymer RDF, substantially more. The table shows that the LSRV/AV_{600} ratio runs from 5 to 41 times higher for the new NBRDF than for the $CaCO_3$-biopolymer RDF.

High LSRV/AV_{600} ratio is important for deep water drilling. High LSRV and YP are needed for good hole cleaning characteristics,[10] but high LSRV is usually achieved in conventional brine-based RDF's by allowing the AV_{600} to run up to high values (**Table 8**). High AV_{600} for deep water drilling usually implies high ECD's. An additional advantage of the new NBRDF for deepwater drilling is evident in **Figure 3**. This figure provides a temperature dependence comparison of two 13.5-lb/gal RDF's – the NBRDF and a biopolymer-based RDF (*cf*. right hand side of **Table 6**). The data illustrate a significant increase in viscosity, especially at the higher shear rate, AV_{600}, for the biopolymer-based RDF. In contrast, the rheologies of the NBRDF are relatively flat with decreasing temperature, a characteristic that makes the NBRDF attractive for applications in deep water where the fluid is exposed to relatively low temperatures for extended periods of time.

Easy to Engineer and Maintain

Because the new NBRDF is formulated from fewer components than conventional RDF's, the new system is inherently easy to mix, engineer, and maintain. Because there is no biopolymer in the formulation, no pre-hydration of polymer or special mixing is required.

Laboratory and small-scale yard tests, as well as full scale tests done in plant and on rig for the field trial,[17] have shown that the system can be put together under very low shear conditions, with no adjustments to base brine pH. A paddle mixer has been proven to give enough shear to put a system together, although depending on temperature and mixing facilities, this may take 2 to 4 hours.

Evaluations were conducted on the new NBRDF system to determine, independently, the effects of drill solids and cement. For each test, a 13.5-lb/gal fluid was prepared and properties recorded. Contaminants were added to the samples, which were then hot-rolled for predetermined time periods prior to cooling and observing final properties. The fluid formulation for contamination testing was 0.97 bbl of 13.2-lb/gal $CaBr_2$ brine, 8.0-lb/bbl DFS, and 26.0-lb/bbl ground marble (Gmarb).

Rev Dust[a] and ground Pierre Shale (2µ fraction[b]) were utilized to simulate drill solids. The results are presented in **Table 9**, showing that the new reservoir drilling fluid system is tolerant to drill solids and exhibits rheological stability, especially at low shear rate.

A slurry containing 0.55 bbls. of water and 502 lb/bbl. of finely ground cement was blended, and from that, 0.8% (3.0-lb/bbl equivalent of cement) was added to the fluid. Properties were recorded upon initial contamination and upon hot rolling for 16 hours at 150°F. The results are presented in **Table 10**, showing that the new NBRDF system is tolerant to cement and exhibits rheological stability, especially at low shear. Nevertheless, as with any RDF, drill solids and cement contaminants should be kept under careful control as their presence can lead to formation damage.

Treatment options are readily available in the event of problems while drilling with the new fluid or with the conditioning of the fluid. Examples of typical drilling problems include colloids build up with associated high methylene blue test (MBT) values, high low-gravity solids, drilling through shale intervals, and low 6/3 rpm readings.[18] The recommended treatments are given in **Table 11**.[18] In the case of low 6/3 rpm readings, for example, there are at least four different options to consider:

- Treat the system with HRMgO at 0.25 lb/bbl increments.
- Treat the system with DFS at 0.2 lb/bbl increments.
- Treat the system with $MgCl_2{\cdot}6H_2O$ at 0.5 lb/bbl increments.
- When subject to temperatures of 200°F to 250°F, treat the system with a special water-miscible glycol ether (WMGE) at 0.03 gallons per barrel increments.

A final option is to treat the system with a combination of the above treatments. It is recommended, in the above treatments and many of those in **Table 11**, that pilot testing at the rig be carried out to determine treatment levels and effectiveness.[18]

The first field application of this new NBRDF was in the Norwegian sector of the North Sea. Fluid properties were easily managed through relatively small additions of DFS and HRMgO. Details of this case history are provided in an upcoming publication.[17]

Good Clean-up

As brine is used to achieve the desired drilling density, the total amount of the sized $CaCO_3$ bridging particles is kept relatively low, 13 to 35 lb/bbl. The combination of

[a] Calcium montmorillonite, 23% quartz, 4% feldspar, 2% dolomite, 5% calcite, 1% siderite, 65% total clay.

[b] 2% kaolinite, 2% chlorite, 19% illite, 14% mixed layer clays, and 63% montmorillonite.

this feature and the elimination of the biopolymer allows the new NBRDF system to offer good clean-up.

Formation damage is minimized by selecting a bridging package that reduces invasion and builds a thin, impermeable filter cake. A concentration of at least 2.5 v/v, and up to 5% v/v bridging solids is needed for effective bridging. The particles must be sized in a range determined by the width of the formation pore throat openings.[19]

In applications where sand control (gravel pack, screens) is applied, it is critical that any solids left in the wellbore can either be flowed back through the completion assembly, or chemically removed.[20,21] The bridging agent builds a filter cake that prevents erosion during gravel packing.[22,23] The filter cake is also designed to "pinhole", rather than lift off in large sheets from the rock face, promoting a more gradual clean-up through the apertures in the completion.[24] **Figure 1** shows an example of that type of filtercake quality.

To assess the clean-up characteristics of the new biopolymer-free RDF formulation, a series of return flow tests with filter cakes deposited on Aloxite disks (**Table 12**) and return permeability tests with filter cakes deposited on Berea sandstone cores (**Table 13**) were run. The filter cakes were deposited from 11.5-lb/gal RDF's with or without simulated drill solids. The 11.5-lb/gal RDF's were either the new biopolymer-free RDF formulation or a "typical" low-solids $CaCO_3$-biopolymer RDF. Both RDF's were based on the same $CaCl_2$ brine.

The data in **Table 12** suggest that on ~30µ pore diameter Aloxite disks, filter-cake clean-up results with 5% HCl and a 3 hour soak for the new NBRDF are generally about as good as or better than for the $CaCO_3$-biopolymer RDF at this density, either with or without simulated drill solids. Photographs showing before and after acid treatment of the NBRDF from **Table 12**, Test 1 are shown in **Figures 1** and **2**. **Figure 1** shows that the filter cake is very thin; and after very mild acid treatment (5% HCl, 3 hr), virtually all residue of the filter cake has disappeared (**Figure 2**).

A longer soak time, 6 hours, with stronger acid, 10% HCl, improved the $CaCO_3$-biopolymer RDF results, making them in one case perhaps slightly better than the 3hr/5% HCl results with the new NBRDF. In the other case, not even the longer soak time and stronger acid made the $CaCO_3$-biopolymer RDF results improve enough to become comparable with those of the new NBRDF at this same density.

One major disadvantage of comparative return flow tests is that the Aloxite disk does not fully simulate the character of a reservoir rock and is typically only ~¼ inch thick, whereas core samples can be of substantially greater length-to-diameter ratio. A major advantage of Aloxite disk tests is that breaker treatments typically have a much greater action upon the filter cake than on the underlying porous medium. A comparable statement concerning core samples is often not true. Also, within a given lot of Aloxite disks, the variations in key parameters like porosity and permeability from disk to disk is generally lower than comparable variations from core sample to core sample. Thus both return flow tests on Aloxite and return permeability tests on Berea sandstone cores were run. The results of comparative return permeability tests on Berea sandstone cores are given in **Table 13**.

These data suggest that lift-off pressures are generally lower for the new NBRDF than for the $CaCO_3$-biopolymer RDF at this density; and return permeabilities are generally higher for the new non-biopolymer RDF than for the $CaCO_3$-biopolymer RDF.

Conclusions

The new fluid system is unique,[25] in that it derives its viscosity solely from an interaction between a specially modified starch (DFS) and an inorganic magnesium compound (HRMgO). It contains no biopolymers, such as xanthan gum or scleroglucan. The combination of DFS and HRMgO yields a low high-shear-rate viscosity fluid, while also providing a high low-shear-rate viscosity.

One of the many benefits of the new fluid system is that it generates excellent drilling fluid properties in brines where conventional systems containing biopolymers cannot; *i. e.*, high-density calcium and zinc brines.

The new fluid system is not difficult to put together. Laboratory and small-scale yard tests, as well as full scale tests done in plant and on rig for the field trial, have shown that the system can be put together under very low shear conditions, with no adjustments to base brine pH. A paddle mixer has been proven to give enough shear to put a system together.

Filter cakes from the new fluid system clean up as well as, and perhaps even better than, other low solids water-based RDF systems. The optimum cleanup method should be engineered for each specific application.

The fluid characteristics detailed in this paper will occur only in divalent brines. These comprise calcium chloride, calcium bromide, and zinc bromide, including 1-, 2-, and 3-salt blends.

To date, the system has been proven to work in temperatures up to 250°F. Continued laboratory work is currently in progress to extend this limit.

Nomenclature

AV_{600}

AV_{600} is the apparent viscosity measured on the Fann 35 at 600 rpm, *i. e.*, at the relatively high shear rate of 1022 sec^{-1}.

BTP

BTP = breakthrough pressure. Breakthrough pressure is calculated from the maximum pressure minus the stable pressure when determining the final permeability. It takes into account changes in flow rate by normalizing pressure to flow rate. Breakthrough pressure is permeability dependent due to higher capillary end effects present in lower permeable cores.

DFS

A new reservoir drilling fluid system has been developed that utilizes a non-biopolymer, acid- or enzyme-soluble polymer that serves both as viscosifier and fluid-loss additive when combined with highly activated magnesium oxide and a dense, divalent-cation-based brine. This unique dual-function starch (DFS) viscosifier and filtrate reducer for the new fluid system is designated DFS. DFS is a specially processed, high molecular weight branched-chain starch derivative that generates elevated low-shear-rate viscosities and controls high temperature-high pressure filtrate loss in divalent salt brines.

DFSI

A dual-function glycol used for shale inhibition (DFSI) and to improve the lubricity of the new fluid system is designated DFSI.

GMarb

A range of specially ground marble (GMarb) that exceeds 98% acid solubility is designated GMarb. These $CaCO_3$-containing products are blended into various particle size distributions in conformance with predictions of the particle-size-distribution software to ensure ultra-low fluid loss and minimize formation invasion.

FIP

FIP = flow initiation pressure = BTP.

HRMgO

A dual-function fine particle size, highly reactive inorganic magnesium oxide (HRMgO) compound that controls the pH and interacts synergistically with DFS in calcium and zinc brines to enhance the LSRV is designated HRMgO. HRMgO stabilizes the LSRV of the fluid and provides an alkalinity source.

IK

IK = Initial Permeability.

LSRV

LSRV = low-shear-rate viscosity, the viscosity measured at a shear rate of 0.0636 sec^{-1}.

MBT

MBT = methylene blue test.

NBRDF

A new non-biopolymer reservoir drilling fluid (NBRDF) system has been developed that utilizes a non-biopolymer, acid- or enzyme-soluble polymer that serves both as viscosifier and fluid-loss additive when combined with highly activated magnesium oxide and a dense, divalent-cation-based brine. This new fluid system is designated NBRDF.

RDF

RDF = a reservoir drilling fluid; also referred to as a reservoir drill-in fluid (DIF).

RK

RK = Return Permeability.

%R

%R = % Return Permeability.

$\% R_{inj.dir}$

$\% R_{inj.dir}$ = the ratio of the final flow rate in the injection direction to the initial flow rate in the injection direction, expressed as a percentage.

$\% R_{prod.dir}$

$\% R_{prod.dir}$ = the ratio of the final flow rate in the production direction to the initial flow rate in the production direction, expressed as a percentage.

VLO

VLO = Volume Leak-off after mud exposure. VLO is the volume of mud and filtrate that enters the core after 360 minutes of exposure at 500 psi overbalance pressure.

WMGE

A dual-function water-miscible glycol ether (WMGE) which enhances the viscosity of the new fluid system mixed in calcium chloride, calcium bromide, and zinc bromide brines and provides lubricity is designated WMGE.

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Table 1 Typical Properties of the New Non-Biopolymer Fluid System	
Density (lb/gal)	11.5 –17.5
PV (cP)	12-30
YP (lb/100ft^2)	10-35
10 sec gel (lb/100ft^2)	3-10
10 min gel (lb/100ft^2)	5-12
pH	6.5-9.0 for densities 11.5 to 14.5 (not zinc-based brines) 4.0-7.0 for densities 14.0 to 17.5 (zinc-based brines)
LSRV (cP)	5,000 - 40,000
HPHT @250 psi, 185°F	
20-micron disk spurt (mL)	≤2.0
30 min (mL)	≤10.0

Table 2

11.5 lb/gal Reservoir Drilling Fluid at 185ºF				**14.5 lb/gal Reservoir Drilling Fluid at 235ºF**		
Conc (lb/bbl)			RDF Formulation			Conc (lb/bbl)
0.969			11.2 lb/gal $CaCl_2$ / -4°F TCT ------ Base Brine (bbl) ------- 14.2 lb/gal / +58°F TCT			0.98
0.25			HRMgO			0.25
8.0			DFS			8.0
25.0			GMarb			23.0
			Properties			
Initial	Hot Roll	Static Age		Initial	Hot Roll	Static Age
66	60	70	600	54	68	64
43	40	46	300	34	45	44
23	20	24	PV	20	23	20
20	20	22	YP	14	22	24
34	32	37	200	27	37	35
23	22	26	100	18	26	25
5	5	7	6	5	8	8
4	4	6	3	4	6	7
5	4	7	10 sec Gel	5	6	7
6	5	8	10 min Gel	7	7	8
14,000	10,900	17,900	LSRV @ 0.0636 sec^{-1}	13,500	16,800	13,000
8.4	7.7	8.1	pH	5.9	5.9	6.0
424	363	511	LSRV/ AV_{600}	500	494	406
Rheological properties were recorded at 120°F. Hot Roll and Static Age at 185°F for 16 hours. No settling or separation observed in aged samples.				Rheological properties were recorded at 120°F. Hot Roll and Static Age at 235°F for 16 hours. No settling or separation observed in aged samples.		

Table 3

14.0 lb/gal Reservoir Drilling Fluid at 200ºF Conc (lb/bbl)	RDF Formulation	16.5 lb/gal Reservoir Drilling Fluid at 185ºF Conc (lb/bbl)
0.95	13.8 lb/gal ------ Base Brine (bbl) ------- 16.37 lb/gal / -6°F TCT	0.958
----	WMGE	0.59
----	$MgCl_2{\cdot}6H_2O$	1.00
0.25	HRMgO	2.00
8.0	DFS	8.0
30.0	GMarb	23.0

Properties

Initial	16 hr Hot Roll	16 hr Static Age	60 hr Hot Roll	60 hr Static Age		Initial	Hot Roll	Static Age
55	66	70	65	69	600	85	114	93
37	44	50	43	49	300	53	74	60
18	22	20	22	20	PV	32	40	33
19	22	30	21	29	YP	21	34	27
31	36	42	34	41	200	40	58	47
22	26	31	24	30	100	25	40	32
9	9	13	8	12	6	5	8	7
8	7	11	6	10	3	3	6	5
10	8	12	7	11	10 sec Gel	3	6	6
14	9	13	8	12	10 min Gel	4	7	7
28,200	15,500	32,200	12,600	31,800	LSRV @ 0.0636 sec^{-1}	2,400	14,700	27,700
7.6	7.9	7.7	7.8	7.7	pH	4.8	5.0	5.1
1,025	470	920	388	922	LSRV/ AV_{600}	56	258	596

14.0 lb/gal fluid: Rheological properties were recorded at 120°F. Hot Roll and Static Age at 200°F for 16 and 60 hours, as noted. No settling or separation observed in aged samples.

16.5 lb/gal fluid: Rheological properties were recorded at 120°F. Hot Roll and Static Age at 185°F for 16 hours. No settling or separation observed in aged samples.

HTHP Fluid Loss

sat'd 750 mD Aloxite disk @200°F, 500 psid

	Initial	16 hr Hot Roll	16 hr Static Age
Spurt (mL)	1.0	1.0	1.0
1 hr (mL)	3.5	4.0	4.0

sat'd 5 µ Aloxite disk @ 185°F, 250 psid

	Initial	16 hr Hot Roll	16 hr Static Age
Spurt (mL)	2.0	1.5	2.0
1 hr (mL)	3.0	3.0	3.0

Table 4

11.4 lb/gal Reservoir Drilling Fluid at 200-250°F				11.75 lb/gal Reservoir Drilling Fluid at 200-250ºF		
Conc (lb/bbl)			RDF Formulation			Conc (lb/bbl)
0.97			11.1 lb/gal / +4°F TCT ------ Base Brine (bbl) ------- 11.6 lb/gal stock brine			0.99
0.25			HRMgO			0.25
8.0			DFS			8.00
24.0			GMarb			13.0
			Properties			
Initial	Hot Roll 200°F, 16 hr	Static Age 250°F, 16 hr		Initial	Hot Roll 200°F, 16 hr	Static Age 250°F, 16 hr
61	60	71	600	62	79	78
40	40	50	300	38	50	51
21	20	21	PV	24	29	27
19	20	29	YP	14	21	24
32	32	42	200	29	39	41
21	22	31	100	18	26	28
5	5	11	6	3	6	8
4	4	9	3	2	4	6
5	4	10	10 sec Gel	2	5	7
7	5	11	10 min Gel	4	6	8
24,500	10,900	31,900	LSRV @ 0.0636 sec^{-1}	13,100	12,500	31,200
7.7	7.7	6.8	pH	8.7	8.7	8.6
803	363	899	LSRV/ AV_{600}	423	317	800
Rheological properties were recorded at 120°F. Hot Roll at 200°F for 16 hours and Static Age at 250°F for 16 hours. No settling or separation observed in aged samples.				Rheological properties were recorded at 120°F. Hot Roll at 200°F for 16 hours and Static Age at 250°F for 16 hours. No settling or separation observed in aged samples.		

HTHP Fluid Loss

sat'd 5 µ Aloxite disk, 250°F, 250 psid			
	Initial	16 hr Hot Roll	16 hr Static Age
Spurt (mL)	0.0	0.0	0.0
30 min (mL)	3.0	3.5	2.5

sat'd 5 µ Aloxite disk, 250°F, 250 psid			
	Initial	16 hr Hot Roll	16 hr Static Age
Spurt (mL)	0.0	0.0	0.0
30 min (mL)	6.0	4.0	5.0

Table 5

12.5 lb/gal Reservoir Drilling Fluid at 200-250ºF		14.0 lb/gal Reservoir Drilling Fluid at 210-260ºF
Conc (lb/bbl)	RDF Formulation	Conc (lb/bbl)
0.97	12.17 lb/gal $CaBr_2$ ------ Base Brine (bbl) ------- 13.8 lb/gal / -37°F TCT	0.98
0.03	WMGE (gal/bbl)	----
0.50	HRMgO	0.25
8.0	DFS	8.00
30.0	GMarb	21.75

Initial	Hot Roll 200°F, 16 hr	Static Age 250°F, 16 hr	Properties	Initial	Hot Roll 210°F, 16 hr	Static Age 260°F, 16 hr
52	52	49	600	60	74	69
38	38	35	300	39	48	44
14	14	14	PV	21	26	25
24	24	21	YP	18	22	19
32	32	29	200	32	38	35
24	24	21	100	22	27	24
10	10	8	6	6	7	7
8	8	7	3	4	6	6
9	9	8	10 sec Gel	5	7	7
11	10	9	10 min Gel	7	8	8
44,400	35,500	34,900	LSRV @ 0.0636 sec^{-1}	16,500	14,900	17,900
9.2	9.1	9.0	pH	7.4	7.4	7.4
1,710	1,370	1,420	LSRV/ AV_{600}	550	403	519

Rheological properties were recorded at 120°F.
Hot Roll at 200°F for 16 hours and Static Age at 250°F for 16 hours.
No settling or separation observed in aged samples.

Rheological properties were recorded at 120°F.
Hot Roll at 210°F for 16 hours and Static Age at 260°F for 16 hours.
No settling or separation observed in aged samples.

sat'd 43 µ Aloxite disk, 250°F, 550 psid				HTHP Fluid Loss	sat'd 43 µ Aloxite disk, 250°F, 550 psid			
	Initial	16 hr Hot Roll	16 hr Static Age			Initial	16 hr Hot Roll	16 hr Static Age
Spurt (mL)	3.5	3.5	3.5		Spurt (mL)	0.0	0.0	0.0
30 min (mL)	8.0	8.5	8.0		30 min (mL)	3.5	3.0	4.0
1 hr (mL)	10.0	12.0	10.0					

Table 6

12.5 lb/gal Reservoir Drilling Fluid at 235ºF				13.5 lb/gal Reservoir Drilling Fluid at 235ºF		
Conc (lb/bbl)			RDF Formulation			Conc (lb/bbl)
0.98			12.25 lb/gal brine ------ Base Brine (bbl) ------- 13.25 lb/gal brine			0.97
0.25			HRMgO			0.25
8.0			DFS			8.0
23.0			GMarb			26.0
			Properties			
Initial	Hot Roll	Static Age		Initial	Hot Roll	Static Age
45	50	49	600	63	76	73
30	34	34	300	44	52	52
15	16	15	PV	19	24	21
15	18	19	YP	25	28	31
24	28	29	200	36	40	43
17	21	21	100	26	29	33
6	8	9	6	10	10	13
5	7	8	3	9	8	11
7	7	8	10 sec Gel	11	8	11
12	8	9	10 min Gel	14	10	13
35,500	23,200	35,800	LSRV @ 0.0636 sec^{-1} 3 min	39,600	30,300	78,600
25,500	22,000	28,500	LSRV @ 0.0636 sec^{-1} 4 min	36,000	31,200	60,700
20,900	23,000	26,100	LSRV @ 0.0636 sec^{-1} 5 min	30,200	31,700	55,100
17,800	25,200	24,900	LSRV @ 0.0636 sec^{-1} 6 min	23,700	33,800	48,800
8.0	8.4	7.0	pH	7.8	7.0	7.6
791	1,010	1,020	LSRV/ AV_{600}	752	889	1,340
Rheological properties were recorded at 120°F. Hot Roll and Static Age at 235°F for 18 hours. No settling or separation observed in aged samples.				Rheological properties were recorded at 120°F. Hot Roll and Static Age at 235°F for 18 hours. No settling or separation observed in aged samples.		

sat'd 750 mD Aloxite disk, 235°F, 500 psid				HTHP Fluid Loss	sat'd 750 mD Aloxite disk, 235°F, 500 psid			
	Initial	18 hr Hot Roll	18 hr Static Age			Initial	18 hr Hot Roll	18 hr Static Age
Spurt (mL)	0.5	1.0	1.0		Spurt (mL)	1.0	1.0	1.0
1 hr (mL)	3.5	4.0	4.5		1 hr (mL)	4.0	4.5	4.5

Table 7
Viscosity Adjustment of 14.0 lb/gal Reservoir Drilling Fluid

RDF Formulation	Conc (lb/bbl)
Base Brine (bbl) ------- 13.8 lb/gal $CaBr_2$	0.95
HRMgO	0.25
DFS	8.0
GMarb	26.0

Properties

	Initial	18 hr. Hot Roll 180°F	AHR +2 lb/bbl HRMgO	AHR+HRMgO +3% 14.2 lb/gal $CaBr_2$
600	66	75	86	75
300	44	49	57	51
PV	22	26	29	26
YP	22	23	28	25
200	35	38	45	41
100	24	25	31	28
6	8	6	9	7
3	6	4	7	5
10 sec Gel	6	5	7	6
10 min Gel	8	6	12	9
LSRV @ 0.0636 sec^{-1}	23,600	10,500	30,500	35,300
pH	7.6	7.9	7.7	7.8
LSRV/ AV_{600}	715	280	709	941

Rheological properties were recorded at 120°F.
LSRV raised with addition of HRMgO
High end rheology lowered with addition of 14.2 $CaBr_2$
One fluid sample used for all viscosity adjustments

Table 8
Comparison of Two 14.0 lb/gal RDF's at 200ºF

Non-Biopolymer RDF (*cf.* Table 3 – left-hand side)		**$CaCO_3$-Biopolymer RDF**	
RDF Formulation using 0.95 bbl 13.8 lg/bal $CaBr_2$ Brine	Conc (lb/bbl)	RDF Formulation using 0.50 bbl 13.5 lb/gal $CaBr_2$ brine + 0.44 bbl 14.2 lb/gal $CaBr_2$ brine (later)	Conc (lb/bbl)
13.8 lb/gal $CaBr_2$ Base Brine (bbl)	0.95	Water	0.06
HRMgO	0.25	14.2 lb/gal brine (bbl)	0.44
DFS	8.0	Special Starch Derivative	4.50
Gmarb	30.0	Clarified XC-type Biopolymer	1.00
		pH buffer	0.25
		14.2 lb/gal brine (bbl)	0.44
		pH buffer	0.25
		GMarb	30.0

Properties

Initial	Hot Roll		Initial	Hot Roll
55	66	600	103	118
37	44	300	76	88
18	22	PV	27	30
19	22	YP	49	58
31	36	200	64	74
22	26	100	46	44
9	9	6	11	14
8	7	3	7	9
10	8	10 sec Gel	8	9
14	9	10 min Gel	9	10
28,200	15,500	LSRV @ 0.0636 sec^{-1} 6 min	1,300	5,000
7.6	7.9	pH	7.8	7.0
1,025	470	LSRV/ AV_{600}	25	85

Rheological properties were recorded at 120°F.
Hot Rolled at 200°F for 16 hours.
No settling or separation observed in aged samples.

Table 9
The Effect of Drill Solids on the New Reservoir Drilling Fluid Rheology

	Initial	Initial w/ 15 lb/bbl Rev Dust, 5 lb/bbl Pierre Shale	Hot Rolled @ 185°F, 16hr	Hot Rolled @ 185°F, 38hr	Added 5 lb/bbl Rev Dust and 1.7 lb/bbl Pierre Shale / Hot Rolled @ 185°F, 93hr
Plastic viscosity (cP)	17	22	27	25	26
Yield point (lb/100 ft^2)	12	23	26	18	23
10 sec gel (lb/100 ft^2)	3	7	7	4	6
10 min gel (lb/100 ft^2)	5	9	8	5	7
LSRV @ 0.0636 sec^{-1} (cP)	5,700	19,300	14,700	9,300	11,000

Table 10
The Effect of Cement Contamination

	Upon Initial Contamination	Hot Rolled 150°F/16 hours
Plastic viscosity (cP)	17	21
Yield point (lb/100 ft^2)	12	23
10 sec gel (lb/100 ft^2)	3	5
10 min gel (lb/100 ft^2)	5	6
LSRV @ 0.0636 sec^{-1} (cP)	10,400	23,400
PH	5.5	8.5
Spurt (mL)	1.5	1.5
30 min (mL)	5.5	3.5

Table 11
Recommended Treatments for the New Non-Biopolymer Reservoir Drilling Fluid (NBRDF) System

Potential Problems	Treatment
Colloids Build Up w/High MBT	Dilute system w/base brine. Do not dilute w/drill water. Pilot test dilution treatment, to verify whether HRMgO and DFS treatments are required.
High LGS (>3% by volume)	Consider a 10-50% whole reservoir drilling fluid "dump and dilute".
Drilling Shale Intervals (>30%)	Pre-treat system with 1-3% DFSI.
Sloughing Shales	Increase reservoir drilling fluid weight with base brine then re-build system with additives.
High Torque/Drag/Poor Sliding	Treat with 3 –5 % DFSI Sweep hole w/50 bbl of a NBRDF-variant pill (or 5% of circ. Volume) containing 5 lb/bbl of very fine carbonate. The pill would be formulated with DFS and HRMgO, but with less total carbonate and all of it in the very fine particle size range. 1-2 lb/bbl of HEC may also be added.
High PV	Dilute with base brine and maintain other properties.
High Gels	Dilute with base brine and maintain other properties.
Low 6/3 rpm Readings	Treat system w/ HRMgO at 0.25 lb/bbl increments.* Treat system w/ DFS at 0.2 lb/bbl increments.* Treat system w/ $MgCl_2 \cdot 6H_2O$ at 0.5 lb/bbl increments .* When subject to temperatures of 200°F to 250°F, treat system w/ WMGE at 0.03 gallons per barrel increments .* Treat system w/ a combination of the above.*
HighFluid Loss	Treat system w/ 5 lb/bbl of a broad-spectrum carbonate, then check HTHP on bottoms up. If FL still too high, treat system w/ DFS at 0.5 lb/bbl increments and check HTHP on bottoms up.*
Seepage Loss	Sweep hole with 100 bbls of a pill containing 50 lb/bbl of fine carbonate, then treat the system w/ 5 lb/bbl of broad spectrum carbonate if loss persists. Check with geologist for change in formation characteristics.
Hole Cleaning	Sweep hole w/ 50 bbls of base brine followed w/ 50 bbls of DIF viscosified with 1-2 lb/bbl DFS.* Increase pump rate, if possible, and increase 6/3 rpm readings 2-3 points by using HRMgO and/or DFS.* Discuss with “company man” possibility of back reaming prior to connections, and whether a short trip should be made. Difficulty tripping in/out of casing shoe may indicate hole-cleaning problem up inside casing.
*Pilot test kits are required on the rig for testing treatment level and compatibility.	

Table 12
11.5 lb/gal RDF Return Flow Tests

Test #		1	2	3	4	5	6
RDF		Non-B.[2]	Non-B.[2]	Bio[3]	Bio[3]	Bio[3]	Bio[3]
Drill Solids		No	Yes	No	Yes	No	Yes
Spurt[1]		2.0	2.0	5.0	5.0	0.1	2.2
18 hr FL[1]		20	32	18	16	5.1	35
Acid Treatment	% HCl	5	5	5	5	10	10
	Time, hrs.	3	3	3	3	6	6
% $R_{inj.dir.}$ [1,4,5]		100	20	87	0	94	33
% $R_{prod.dir.}$ [1,4,6]		90	85	98	73	91	83

Notes:

1. Tests run with a saturated aloxite disk (29.6µ average pore diameter), 180°F, 300 psid.
2. The new non-biopolymer $CaCl_2$-brine-based RDF.
3. $CaCl_2$-brine-based, $CaCO_3$-biopolymer-containing RDF.
4. Initial and final flow rates were measured with 5 psid controlled pressure differential.
5. The ratio of the final flow rate in the injection direction to the initial flow rate in the injection direction, expressed as a percentage, is % $R_{inj.dir}$.
6. The ratio of the final flow rate in the production direction to the initial flow rate in the production direction, expressed as a percentage, is % $R_{prod.dir}$.

Table 13
11.5 lb/gal RDF Return Permeability Tests

Test #	1	2	3	4	5
11.5 lb/gal RDF Type	$CaCl_2$-Non-Biopolymer	$CaCl_2$-Non-Biopolymer	$CaCl_2$-Biopolymer	$CaCl_2$-Biopolymer	$CaCl_2$-Biopolymer
Drill Solids	No	Yes	No	No	Yes
IK	376.2	351.6	369.5	324.4	352.3
VLO	3.67	6.38	4.53	3.08	3.60
RK	304	335	225	143	275
% R	80.9	95.2	60.9	44.2	77.9
BTP	23.1	30.7	33.3	40.7	39.5

IK = Initial Permeability, mD
VLO = Volume Leak-off after drilling fluid exposure, cc

- VLO is the volume of drilling fluid and filtrate that enters the core after 360 minutes of exposure at 500 psi overbalance pressure.

RK = Return Permeability, mD
%R = % Return Permeability
BTP = Breakthrough Pressure, psi

- Breakthrough Pressure is calculated from the maximum pressure minus the stable pressure when determining the final permeability. It takes into account changes in flow rate by normalizing pressure to flow rate. Breakthrough Pressure is permeability dependent due to higher capillary end effects present in lower permeable cores.

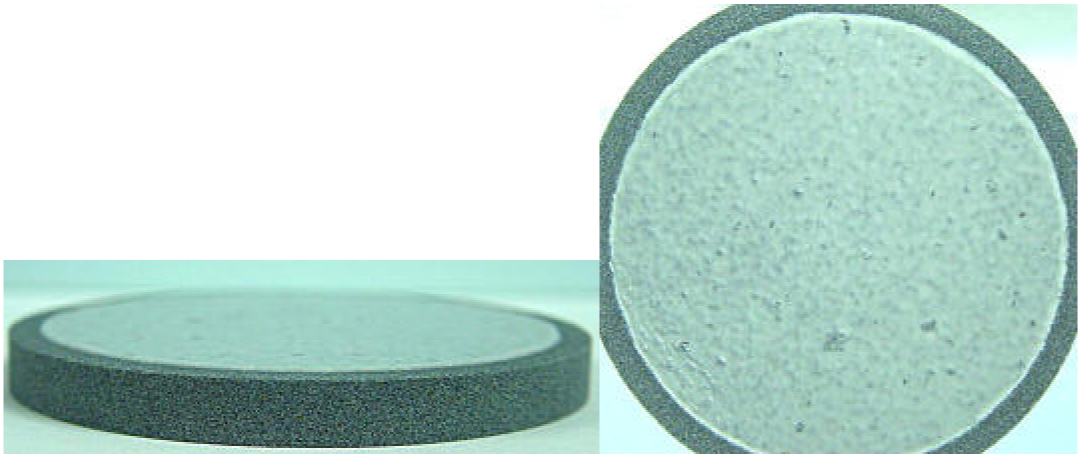

Fig. 1 – Initial filter cake from the 11.5 lb/gal NBRDF fluid in Table 12, Test #1 (before acid treatment).

Fig. 2 - Filter cake from the 11.5 lb/gal NBRDF fluid in Table 12, Test #1 after acid treatment. Note that the residual cake is so thin that the disk type number is easy to read through the residual cake.

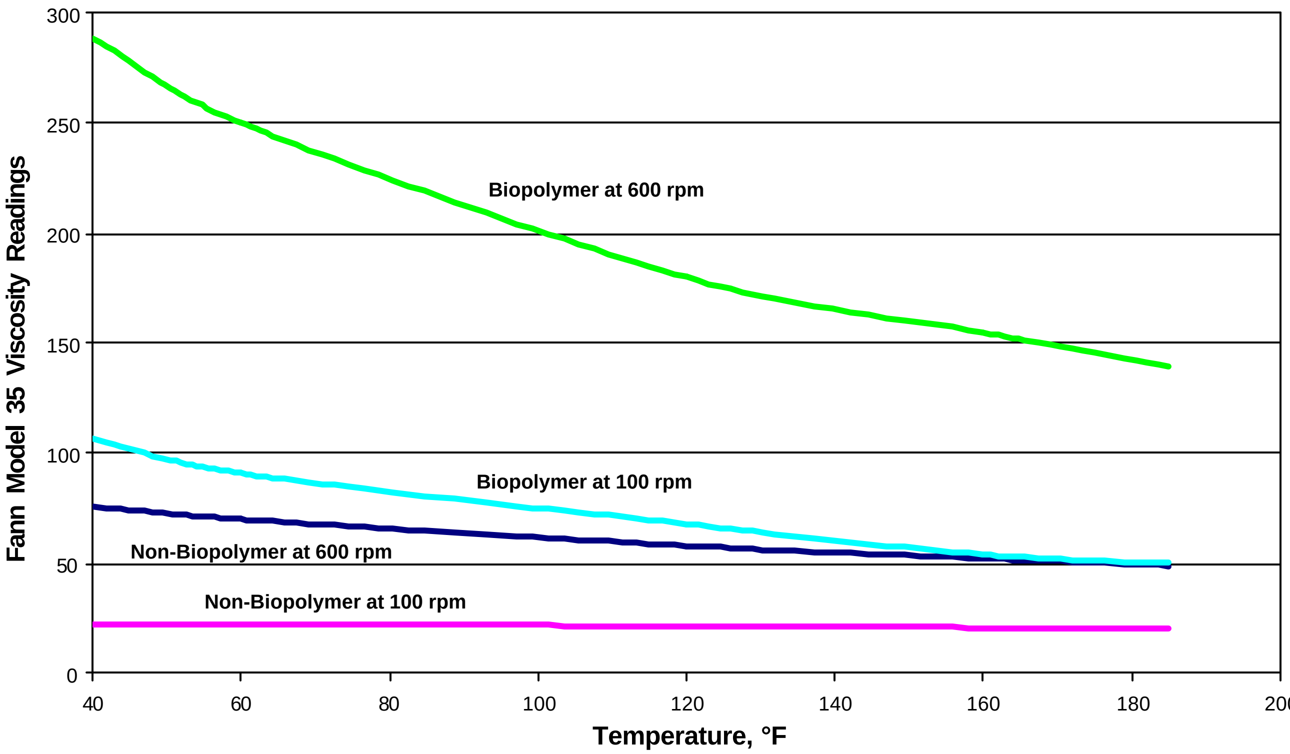

Fig. 3 - A comparison of the temperature dependence of two 13.5 lb/gal RDF's – one biopolymer-based and one which contains no biopolymer (*cf*. the right hand side of Table 6). The data illustrates a significant increase in viscosity, especially at the higher shear rate associated with the 600 rpm readings, for the biopolymer-based RDF. In contrast, the rheologies of the non-biopolymer RDF are relatively flat with decreasing temperature, a characteristic that makes the non-biopolymer RDF attractive for applications in deep water where the fluid is exposed to relatively low temperatures for extended periods of time.