

# RECENT DEVELOPMENTS IN GEOTHERMAL DRILLING FLUIDS

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## ABSTRACT

In the past, standard drilling muds have been used to drill most geothermal wells. However, the harsh thermal and chemical environment and the unique geothermal formations have led to such problems as excessive thickening of the fluid, formation damage, and lost circulation.

This paper describes three recent development efforts aimed at solving some of these drilling fluid problems. Each of the efforts is at a different stage of development. The Sandia aqueous foam studies are still in the laboratory phase, NL Baroid's polymeric deflocculant is soon to be field tested, and the Mudtech high-temperature mud was field tested several months ago.

Low density and the capability to suspend particles at low relative velocities are two factors which make foam an attractive drilling fluid. The stability of these foams and their material properties at high temperatures are presently unknown, and this lack of information has precluded their use as a geothermal drilling fluid.

The aqueous foam studies being conducted at Sandia are aimed at screening available surfactants for temperature and chemical stability. Approximately 100 surfactants have been tested at temperatures of 260° and 310°C (500° and 590°F), and several of these candidates appear very promising.

NL Baroid has developed a polymeric deflocculant for water-based muds which shows promise in retarding thermal degradation effects and associated gelation. Formulations containing this new polymer have shown good rheological properties up to 260°C (500°F) in laboratory testing.

A high-temperature mud consisting primarily of sepiolite, bentonite, and brown coal has been developed by Mudtech, Inc. A field test of this mud was conducted in a geothermal well in the Imperial Valley of California in May 1980. The fluid exhibited good hole-cleaning characteristics and good rheological properties throughout the test.

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## Introduction

The high temperatures and harsh chemical environment associated with geothermal drilling severely tax the capabilities of ordinary aqueous drilling fluids [1,2]. The high temperatures that are encountered often cause excessive thickening and gelation of the mud, which leads to circulation difficulties, or may even cause lost circulation due to necessarily high pump pressures. Additional geothermal drilling fluid problems include: increased corrosion rates, fluid-formation damage, and logging difficulties.

In recent years, numerous studies have been made of the thermal gelation problem, and considerable improvement has been achieved with good clay solids control and the use of stable lignite and lignosulfonate derivatives [3-8]. These products are excellent gelling retardants at temperatures of 150°C to 175°C, however, they are susceptible to thermal degradation at temperatures in excess of 200°C. As this degeneration of properties increases, either the mud constituents must be continually replaced or the use of more stable materials are necessary [2,9].

This paper describes three different approaches to solving some of the problems mentioned above. The first discussion deals with a new synthetic polymeric deflocculant used as a high temperature stabilizer developed by NL Baroid. The second section of this paper describes a new high temperature mud formulation by Mudtech, Inc. and the recent field tests of this mud. Lastly, some recent laboratory studies at Sandia National Laboratories aimed at qualifying aqueous foams as a geothermal drilling fluid is presented.

### Polymeric Deflocculants for Stabilizing Water-Base Drilling Fluids at Elevated Temperatures

This section is concerned with the study of a new synthetic polymeric deflocculant as a high temperature stabilizer. The experimental polymeric deflocculant herein referred to as XPD is an acrylate ester copolymer of low molecular weight. It is strongly anionic with additional hydrogen-bonding character. It has a strong affinity for clay. The high temperature properties of XPD were studied in the Fann Consistometer, Fann 50B Viscometer, and static aging cells. High temperature electrolyte effects were also studied.

#### High Temperature Stability

As part of a program on high temperature drilling fluids, temperature-stable deflocculants are being investigated. The initial screening studies use both the Fann Consistometer and the Fann 50B Viscometer. The results with one new experimental polymeric deflocculant (XPD) have been especially promising.

Table 1 shows the drilling fluid formulations that were run in the Fann Consistometer and the Fann 50B viscometer. The muds weighed .3 lb/gal. The new deflocculant (XPD) was added as a 50% solution.

### Fann Consistometer Studies

The Fann Consistometer, Model 55-TDL, with a Honeywell Brown Elektronik Recorder was used. The mechanics of consistometer operation have been described by Weintritt and Hughes [10]. The consistometer allows the monitoring of changes in mud consistency during heating to 500°F and pressures to 20,000 psi. The consistometer operates by magnetically moving a soft iron bob up and down while audio detectors measure the time of travel of the bob. The time varies with the consistency of the mud and is recorded as "viscosity, % of scale" from 0 to 100%. For these experiments, the mud samples were aged by rolling 16 hours at 150°F (65°C) and the pH was adjusted to 11.0. After placing the sample in the consistometer cell, the temperature was raised to 400°F (200°C) as quickly as possible and then held there for about 8 hours. The pressure was maintained at 10,000 psi. Figure 1 compares the relative viscosities of the three muds upon heating to 400°F (200°C).

The base mud system with ferrochrome lignosulfonate (FCL) thickens rapidly and after about 2 hours reaches a consistency where the consistometer bob is completely immobilized. The suspension with the XPD maintains a stable, operational viscosity for over 8 hours or more than 7 hours at 400°F (200°C).

When the deflocculants are combined, an interesting phenomenon is observed. The mud system begins to thicken appreciably after about one hour at 400°F (200°C), reaching a maximum at about one hour and 15 minutes. It then begins to thin and the relative viscosity almost returns to its original level. For the remainder of the 8-hour test period, it remains stable.

This seems to suggest that in the mixed deflocculant system, dispersion at low temperatures is primarily a result of the action of the FCL. Then, as the temperature increases and the FCL begins to fail, there is a short but discernible lag before the XPD takes over and deflocculates the system.

### Fann 50B Viscometer Studies

The Fann 50B Viscometer measures viscosity with a rotating bob while the sample is heated under pressure. The fluid shear force on the bob is electronically transmitted to a recorder to give direct viscosity read-outs. For these tests, the viscometer speed was set at 100 RPM. The temperature controls were adjusted to give staged 400°F, 450°F and 500°F (200°C, 230°C, 260°C) temperatures at one hour intervals. The pressure was kept at 800 psi.

Figure 2 shows the Fann 50B viscosities of the muds in Table 1. The Fann 50B data exhibits some interesting differences when compared to the consistometer data. Shortly after reaching 400°F (200°C), the FCL drilling fluid shows a steady increase in viscosity. Initially the XPD system shows a similar but more rapid increase in viscosity, but then it thins out and remains stable up to 500°F (260°C).

The mud system, containing both FCL and XPD exhibits better rheological stability than either of the individual deflocculant systems, over the entire range from ambient temperature to 500°F (260°C). This behavior suggests a synergism between FCL and XPD.

### Effect of Contaminants

In many cases contaminants play a major role in flow properties, and the types and quantities must be considered when attempting to improve the high temperature stability of drilling fluids. The effects of typical electrolytes on organic-thinned muds containing FCL alone and in combination with XPD were investigated. The contaminants studied were lime, gypsum, and various concentrations of sodium and calcium chloride. Contaminant-treated muds were aged at 150°F (65°C) for 16 hours, and then static aged at 450°F (230°C) for 16 hours in stainless steel cells (800 psi N<sub>2</sub> head). API rheologies, shear strengths and filtration losses were determined before and after static aging. The results presented in Table 2 show that in all cases the properties were better with the formulations containing XPD. The shear strengths, in particular, were significantly lower compared to those of the FCL alone system.

The influence of salt concentration, either NaCl or CaCl<sub>2</sub>, on high temperature properties is illustrated in Figures 3 and 4. Figure 3 shows that for chloride concentrations up to 8,000 mg/l the shear strengths are substantially lower for the system containing XPD. Likewise, Figure 4 shows that the yield points after restirring are lower when XPD is present.

### Conclusions

- Fann Consistometer and Fann 50B Viscometer data show that XPD is an effective viscosity stabilizer at high temperatures.
- The new XPD additive dramatically reduces the shear strength at high temperatures and shows reasonably good contaminant tolerance.
- XPD is a suitable additive to traditional FCL systems for improving their high temperature performance.

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## Field Test of Geothermal Drilling Fluid, HTM-1

The DOE, through Sandia National Laboratories, has funded work to evaluate the thermal stability of commercially available drilling fluids and to formulate an improved geothermal mud. Work in 1976 showed that commercially available water muds had high viscosity, poor filtration properties, and poor corrosivity characteristics at temperatures above 175°C. In 1977 an improved geothermal mud was formulated from water, sepiolite, bentonite, brown coal, sodium polyacrylate, and caustic soda. The geothermal mud, code named HTM-1, was selected by McCullough Geothermal for drilling from mud-up depth (7,600 ft.) to casing depth (10,920 feet) on their Mercer 2-28 Well in Imperial County, California. The Mercer 2-28 Well had previously been drilled for use as an injection well and a string of 13-3/8-inch casing had been installed in the well to a depth of 4,147 feet.

## Field Test Operations

McCullough used a salt gel mud to drill a 12-1/4-inch hole below 13-3/8-inch casing at 4,147 feet on their Mercer 2-28 Well. The salt gel mud was used to drill to 7,600 feet. While drilling with a new bit at 7,600 feet, the salt gel mud was converted to an HTM-1 mud by dilution with 30% by volume of fresh water, followed by treatment with 5 lb/bbl of brown coal, 1 lb/bbl of sodium polyacrylate, and 0.5 lb/bbl of caustic soda. The HTM-1 mud was thinner, contained less bentonite clay, and had better filtration characteristics than the salt gel mud. Daily mud treatments of 1 to 2 lb/bbl of brown coal and 1/4 to 1/2 lb/bbl of sodium polyacrylate were made in order to maintain the API Filtrate below 15 ml and the HT-HP Filtrate (175°C-500 psi) below 50 ml. Daily additions of 1 to 3 lb/bbl of sepiolite were also needed to maintain adequate hole cleaning. Typical mud properties exhibited by the HTM-1 are shown in Table 3.

Drilling rates averaged 7 to 9 feet per hour while drilling with the high temperature mud. No problems were encountered breaking circulation after trips or after logging operations.

Trouble-free drilling was experienced from 7,600 feet to 7,916 feet where a twist-off occurred. The fish was recovered without difficulty and drilling resumed. Mud circulated from the bottom of the well after remaining there for 12 hours was nearly identical to the mud being continually circulated from the well during normal drilling operations.

During a trip to change bits at 8,604 feet, the drill collars were inspected and some were removed from the string because hair-line

cracks were detected. Approximately 60 feet of fill were observed when the new bit reached bottom, so the funnel viscosity was increased slightly by the addition of 2 lb/bbl of sepiolite.

Logs were run without difficulty at 8,866 feet. About 28 feet of fill were detected when the new bit reached bottom. Mud from the bottom of the well had excellent rheological and filtration control properties. Drilling continued to 10,053 feet where a drilling break and a twist-off occurred. The fish was recovered and drilling then proceeded without further difficulties to 10,463 feet. At this depth a wash-out occurred in one of the collars necessitating another fishing job. This fish was also recovered without incident and drilling proceeded to a total depth of 10,920 feet where logs were again run without difficulty.

### Comparison with a Prior Well

In July and August of 1978 McCullough drilled an 8-3/4-inch well, the Mercer 1-28, approximately 1/4 mile north of the Mercer 2-28. Both of the wells were drilled by the same Drilling Contractor with the same drilling rig. The Mercer 1-28 Well was drilled with a mud compounded from sepiolite, regular drilling mud lignite and sodium polyacrylate. Although the well was drilled two years earlier and contained smaller volumes of mud in the hole, data on mud costs and time required to drill the interval can be compared with the data on the recent well. Table 4 shows such a comparison on the two wells.

The data on cumulative costs for the two wells as a function of time is also shown in Figure 5. Mud costs on the Mercer 1-28 Well shown in Table 2 and in Figure 1 were adjusted to reflect a price increase of 20% from 1978 to 1980 and for a volume increase of 60% between a 12-1/4-inch hole and an 8-3/4-inch hole.

### Summary

A new high temperature mud, HTM-1, developed with DOE funding was used to successfully drill a 12-1/4-inch hole from 7,600 feet to 10,920 feet on McCullough Geothermal's Mercer 2-28 Well in Imperial County, California. The mud retained excellent rheological and filtration properties throughout all drilling, fishing and logging operations. Very little time was lost reaming or washing to bottom after trips. Also, when the Mercer 2-28 Well was compared on an equal basis with Mercer 1-28 Well, a larger diameter hole was drilled nine days faster resulting in substantial savings in daily operating costs.

### Aqueous Foam Drilling Fluids

Aqueous foam is a promising drilling fluid for many underpressured geothermal formations. It can minimize damage to the producing formations and eliminate the erosion problems associated with the currently used air drilling techniques. If nitrogen is used as the



gaseous phase in the foam the corrosion problems inherent in geothermal drilling would also be minimized. Low density (25-100 kg/m<sup>3</sup> or 0.025-0.100 liquid volume fraction - LVF) foams have excellent lifting ability because of their relatively high viscosity.

### Surfactant Screening

The major barriers to the use of aqueous foams for geothermal drilling is the lack of data on the chemical stability of the surfactants or foaming agents and their ability to make stable foams in the high temperature geothermal environment. The first step in Sandia's program was to determine the effect of high temperatures and various chemical environments on the ability of a wide variety of commercially available surfactants to make stable aqueous foams. Foams were made and evaluated with surfactant solutions before and after exposure to 260 and 310°C for two hours. Various chemicals were used to simulate the geothermal drilling environment. These included deionized water, 0.1 M hydrochloric acid, 0.1 M sodium hydroxide, 1.0 M sodium chloride, a synthetic geothermal brine and a sodium chloride/calcium chloride brine.

The surfactants were aged and tested as 0.5 percent by weight active ingredients in the various aqueous environments. The solution (0.25ℓ) was aged in 0.5ℓ stainless steel mud aging vessels for all tests. The aging cycle used for all tests was: a) ambient to test temperature -2.0 hours, b) hold at test temperature -2.0 hours, c) test temperature to ambient -3.0 hours. These cycles were programmed with linear ramps up to temperature and down to ambient.

Foams were made for evaluation using a static mixer foam generator with a metered gas and solution supply. This technique provided fine celled foams with controlled density. Foam density was controlled to  $45.0 \pm 5.0 \text{ kg/m}^3$  (0.045  $\pm$  0.05 LVF) for all tests. Foam drainage time, an excellent measure of short time or density stability of aqueous foams, was the primary quantitative test used to measure the effects of the high temperature cycles on the surfactant solutions. The time to fifty percent drainage or weight loss was also measured. A qualitative visual examination of the foams cell structure, with ratings of good, fair or poor given, also proved to be an important measure of the surfactants usability. The ratings are defined as follows: good-small uniform cells, fair-nonuniform cell structure, poor-nonuniform cell structure with large cells. Because some degradation of the surfactant will occur at either 260 or 310°C, the effect of the degradation products on the foam is an important factor. There is evidence of both foam stabilizers, as indicated by increases in drainage time, and antifoams, as indicated by changes in the cell structure after aging the surfactant solutions. The qualitative rating of cell structure provides a coarse but direct measure of antifoam formation after aging. The pH of the solution was also measured before and after aging thus providing another measure of chemical change.

Over 100 commercially available surfactants, including representatives from all major types, have been evaluated. Many of these surfactants would not make foams after exposure to 260°C in deionized water, however, a promising few have been able to make foams after exposure to 260 and 310°C in almost all the chemical environments. The anionic surfactants evaluated included the alkyl sulfates, alkyl ether sulfonates, alkyl sulfonates, alkyl aryl sulfonates, and the fluoroalkyl sulfonates as well as several proprietary materials. Two types of nonionic surfactants were evaluated; the alkyl ethoxylates and the alkyl aryl ethoxylates. The amphoteric surfactants evaluated included the betaine and imidazoline based materials. Two types of cationic surfactants were evaluated; the ethoxylated tertiary amines and several quaternary ammonium materials.

Table 5 presents the data on one surfactant, an alpha olefin sulfonate, evaluated in various chemical environments at 260°C. This surfactant obviously shows promise because of the small changes in drainage, good cell structure after aging, and moderate changes in pH. Because of the large data set for each surfactant a performance rating system was developed to allow the presentation of the results. Table 6 presents data on selected surfactants at 260°C giving only their performance rating in various chemical environments. The ratings are defined as follows: Excellent-E- less than 20 percent decrease in drainage time with good cell structure before and after aging, Good-G- more than 20 percent decrease in drainage time with good cell structure, Poor-P- fair or poor cell structure after aging, Unsatisfactory-U- no foam measurements possible after aging.

## Conclusions

A quick review of the ratings in Table 6 shows that the first three surfactants, from the anionic and amphoteric classes give excellent or good ratings in all environments. The nonionic alkyl ethoxylate has excellent ratings, except in the acid (0.1 M HCL) environment. And finally the alkyl aryl sulfonate rates good except in the 1.0 M sodium chloride and the 0.1 M sodium hydroxide. Table 7 presents the performance ratings for selected surfactants at 310°C. At 310°C only one alpha olefin sulfonate gave excellent or good ratings in all environments except the 0.1 M hydrochloric acid. The proprietary anionic and the nonionic ethoxylated alcohol both show promise in some environments. It is worth noting that all three anionic surfactants have excellent ratings in the 0.1 M sodium hydroxide which is a desirable environment for corrosion control.

These tests have shown that solutions of low cost, widely available organic surfactants will make good foams after exposure to both 260 and 310°C in a wide variety of aqueous environments. The next step in this program is to evaluate the stability of aqueous foams at high temperatures and pressures. An autoclave for these experiments is currently being set up.

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Table 1

Composition of Mud Systems Used  
for Thermal Gelation Tests

<u>Mud System</u>	<u>FCL</u>	<u>XPD</u>	<u>FCL + XPD</u>
Water, bbl	1.0	1.0	1.0
Wyoming Bentonite, lb	25	25	25
Glen Rose Shale, lb	50	50	50
Sodium Hydroxide, lb	1.0	1.0	1.0
FCL, lb	5.0	-	5.0
XPD, lb	-	3.0	3.0

FCL - Ferrochrome Lignosulfonate

XPD - Experimental Polymeric Deflocculant

Table 2

Effect of Contaminants on Muds Static Aged at 232°C (450°F)-Base Mud: FCL System

	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>	<u>8</u>	<u>9</u>	<u>10</u>	<u>11</u>	<u>12</u>	<u>13</u>	<u>14</u>
XPD, lb/bbl		3	3	3	3		3	3	3		3		3	
<u>Contaminant</u>														
Sodium Chloride, ppm Cl x 10 <sup>3</sup>			2	5	8	8								
Calcium Chloride, ppm Cl x 10 <sup>3</sup>							2	5	8	8				
Gypsum, lb/bbl											5	5		
Lime, lb/bbl													5	5
<u>Properties Of Muds After Rolling 16 Hours at 150°F</u>														
Plastic Viscosity, cp	19	17	15	18	18	21	15	36	30	22	26	19	26	19
Yield Point, lb/100 sq. ft.	3	1	2	1	1	2	5	48	43	155	4	1	2	1
10 sec. Gel, lb/100 sq. ft.	1	1	1	1	1	1	1	2	42	53	1	1	1	1
10 min. Gel, lb/100 sq. ft.	1	1	15	2	1	1	1	4	51	55	1	1	1	1
pH	9.7	9.6	9.8	9.5	9.0	9.5	9.4	8.6	8.7	9.0	9.2	9.6	12.1	12.4
<u>pH Adjusted to 11.0 And Muds Aged 16 Hours at 450°F</u>														
Shear Strength, lb/100 sq. ft.	780	30	30	50	160	1010	20	90	120	320	100	720	110	80
<u>Properties after Restirring</u>														
Plastic Viscosity, cp	34	18	16	15	19	35	14	23	11	14	15	37	18	12
Yield Point, lb/100 sq. ft.	16	12	12	33	76	145	16	46	79	146	9	114	40	132
10 sec. Gel, lb/100 sq. ft.	4	2	6	35	66	82	9	23	33	61	3	92	40	60
10 min. Gel, lb/100 sq. ft.	29	21	33	45	75	100	28	40	40	61	47	108	44	146
pH	7.8	8.0	7.6	7.6	7.9	8.0	7.8	7.1	7.5	7.7	7.7	8.0	9.9	10.0
API Filtrate, ml	16.0	9.5	12.5	14.5	18.0	18.5	14.0	31.5	44.5	55.0	16.0	21.0	20.5	22.5

Table 3

## Typical Properties of HTM-1

Density, ppg	9.0-9.1
Funnel Viscosity, sec/qt	35-40
Plastic Viscosity, cp	13-15
Yield Point, lb/100 sq ft	2-5
10-sec Gel, lb/100 sq ft	2
10-min Gel, lb/100 sq ft	15-15
pH	10.5-11.5
API Filtrate, ml	12-14
HT-HP Filtrate (350°F-500 psi), ml	40-50
Solids, % by volume	8-9

Table 4

## Mud Costs and Drilling Time

	<u>Mercer 1-28</u>	<u>Mercer 2-28</u>
Interval (ft)	7,540-11,012	7,600-10,920
Hole Size	8-3/4 in.	12-1/4 in.
Time	36 Days	27 Days
Cost	\$77,898	\$76,566

Table 5

Effect of 260°C (500°F) and Various Chemical Environments  
on an Alpha Olefin Sulfonate Surfactant Solution

<u>Environment</u>	<u>Change in Drainage Time (%)</u>	<u>Cell Structure After Aging</u>	<u>Change in pH</u>
DI H <sub>2</sub> O/Air	+9.1	Good	-0.69
DI H <sub>2</sub> O/N <sub>2</sub>	-3.5	Good	-0.10
1.0 M NaCl/Air	+13.1	Good	+1.60
0.10 M NaOH/Air	-7.4	Good	_____
0.10 M HCl/Air	+28.8	Good	_____
Brine/Air	-10.6	Good	-2.46

Table 6

Surfactant Performance Ratings After 260°C (500°F) Exposure  
For Selected Surfactants

<u>Chemical Type</u>	<u>DI H O Air</u>	<u>DI H O Nitrogen</u>	<u>1.0 M NaCl Air</u>	<u>0.1 M HCl Air</u>	<u>0. 1M NaOH Air</u>	<u>Brine Air</u>
Alpha Olefin Sulfonate	E	E	E	E	E	E
Coco Betaine	E	E	E	E	G	E
Proprietary Anionic	E	E	E	G	E	E
Alkyl Ethoxylate	E	E	E	U	E	E
Alkyl Aryl Sulfonate	G	G	U	G	U	—

E-Excellent    G-Good    U-Unsatisfactory

Table 7

Surfactant Performance Ratings After 310°C (590°F) Exposure  
For Selected Surfactants

<u>Chemical Type</u>	<u>DI H<sub>2</sub>O Air</u>	<u>DI H<sub>2</sub>O Nitrogen</u>	<u>1.0M NaCl Air</u>	<u>0.1M HCl Air</u>	<u>0.1M NaOH Air</u>
Alpha Olefin Sulfonate	G	E	E	P	E
Alpha Olefin Sulfonate	G	G	P	U	E
Proprietary Anionic	E	E	P	U	E
Ethoxylated Alcohol	E	E	U	U	P

E-Excellent    G-Good    P-Poor    U-Unsatisfactory



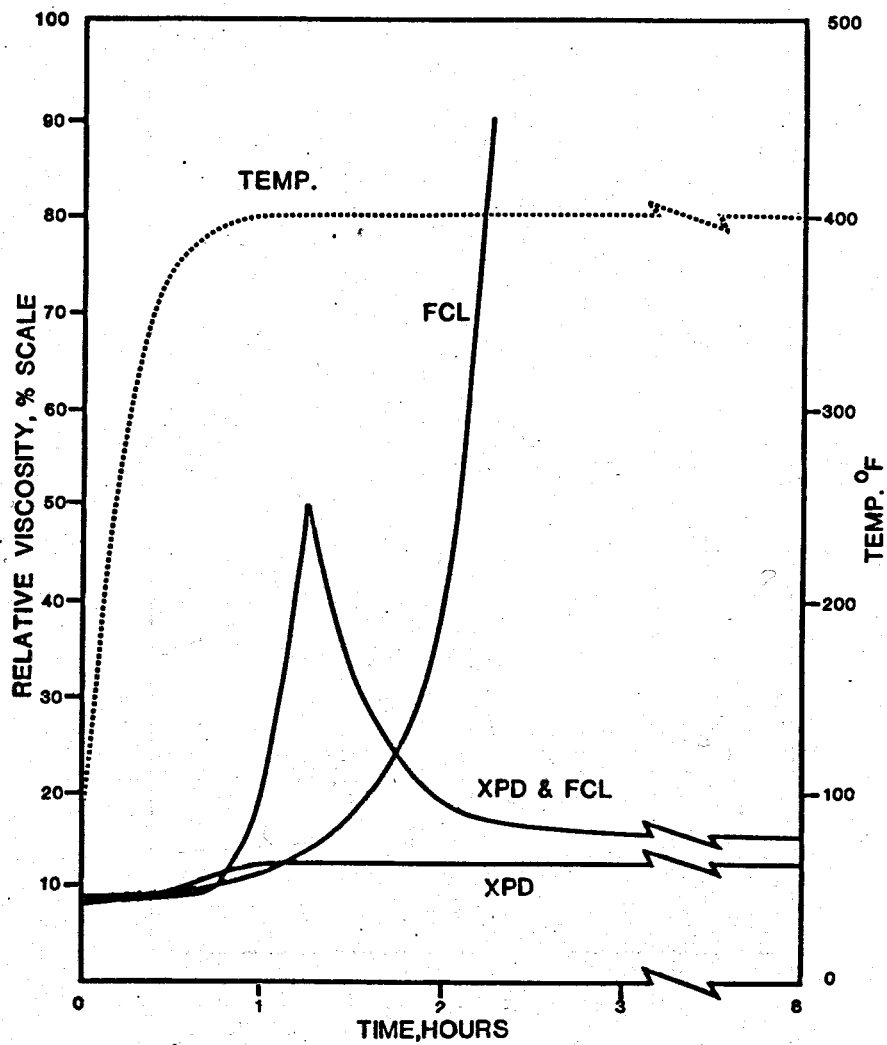


Figure 1. Consistometer Runs at 10,000 psi

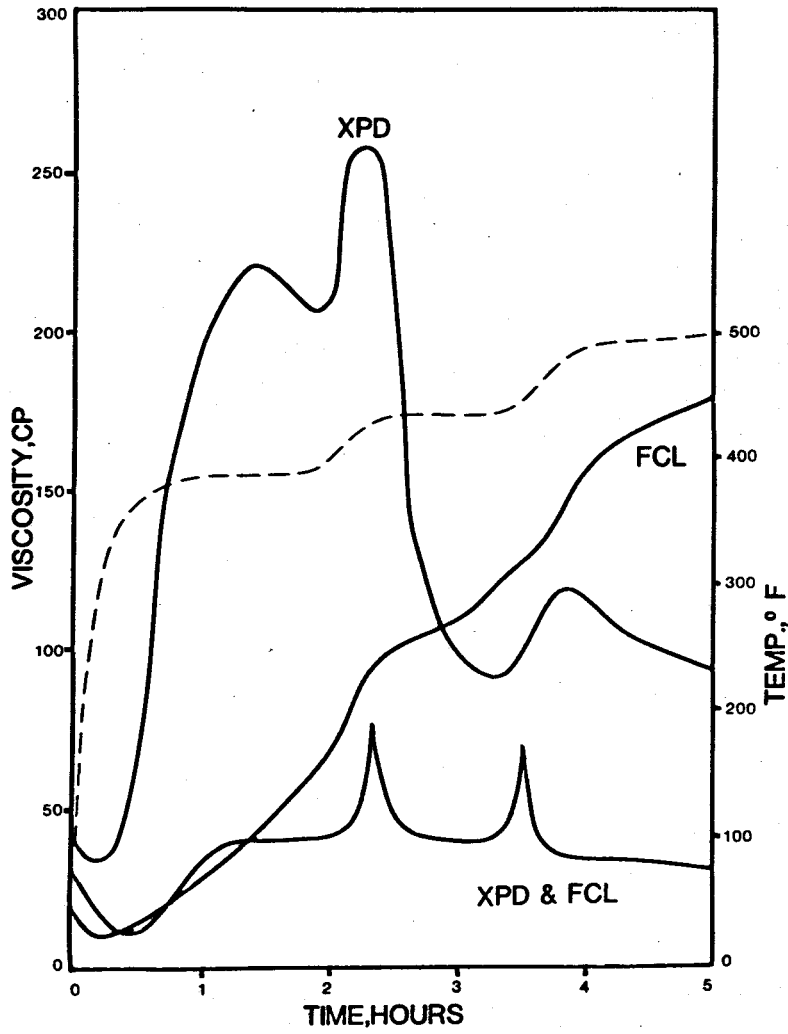


Figure 2. Fann 50B Viscometer Runs at 100 rpm and 800 psi

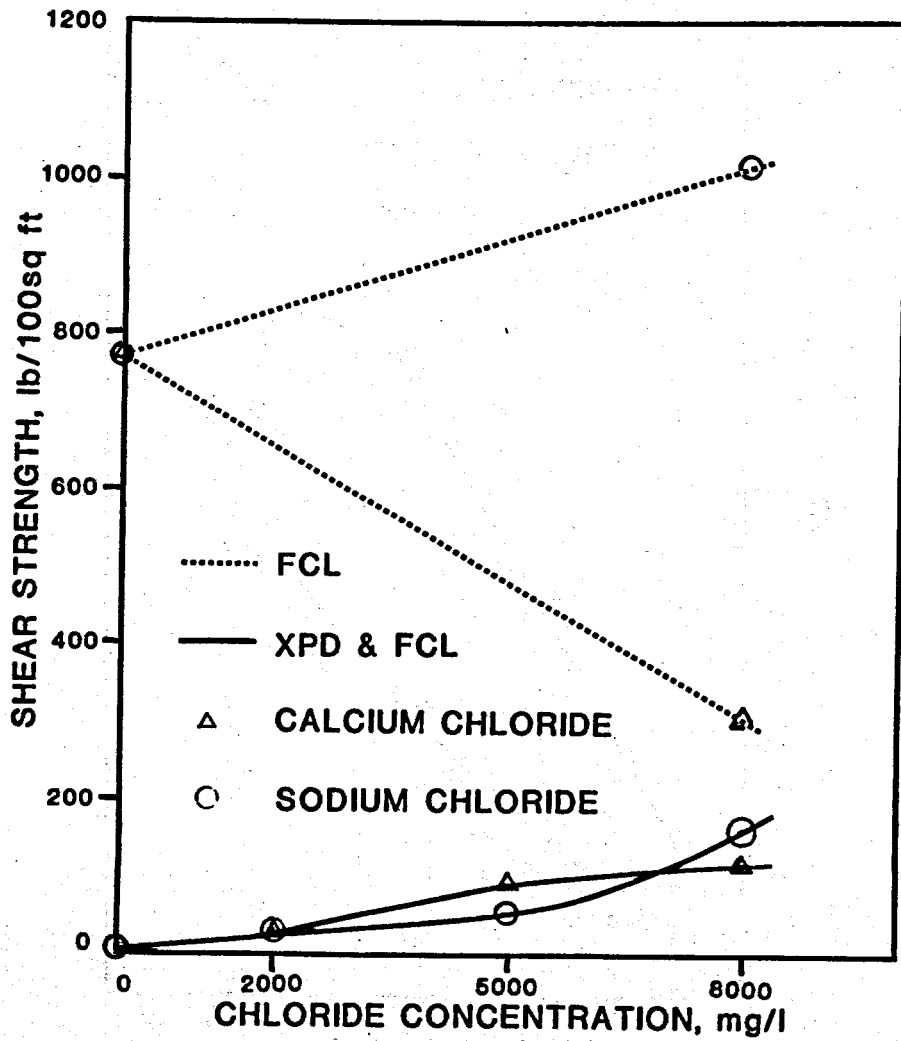


Figure 3. Shear Strengths of Salt Contaminated Muds Static Aged at 230°C (450°F)

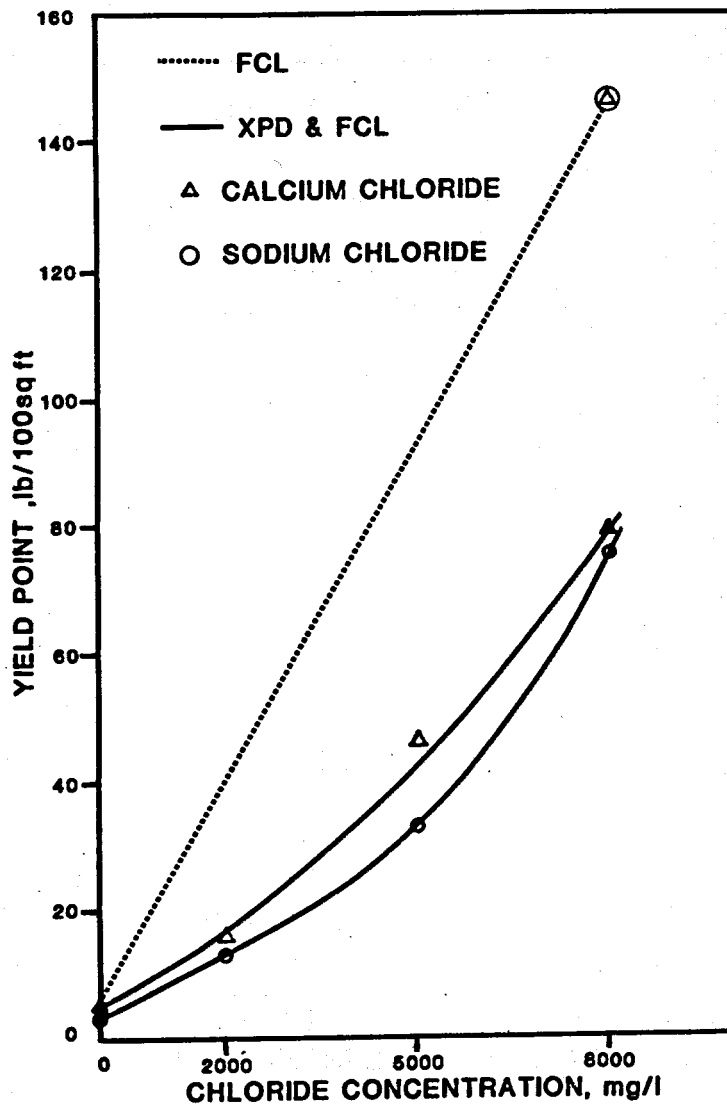


Figure 4. Yield Points of Salt Contaminated Muds Static Aged at 230°C (450°F)

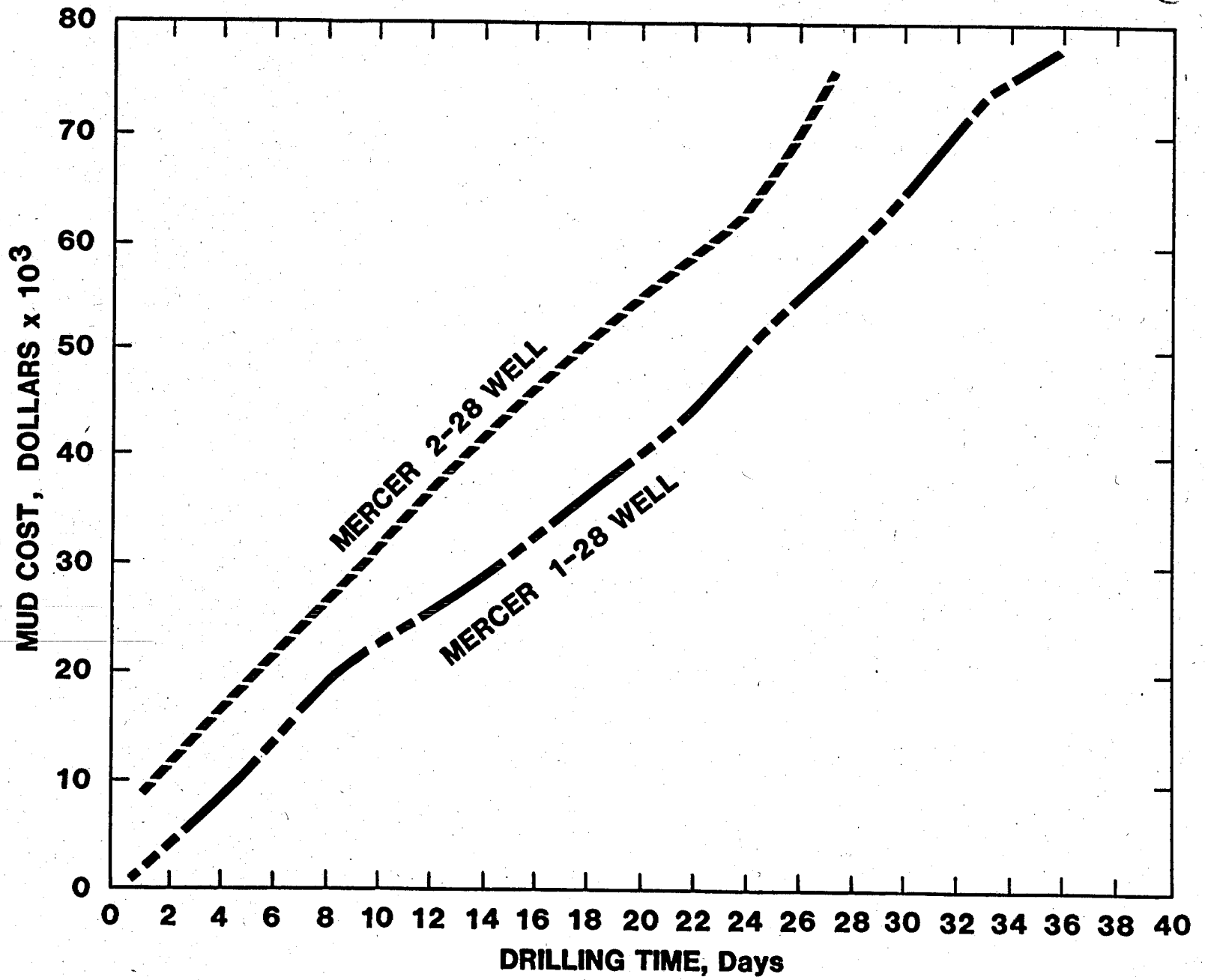


Figure 5. Mud Cost Versus Drilling Time

