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EVALUATION OF COMMERCIALY AVAILABLE GEOTHERMAL DRILLING FLUIDS

MASTER

Larry J. Remont, William A. Rehm,
William J. McDonald, William G. Maurer

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✓ November 1, 1976

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prepared for

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MASTER

Summary

A review of geothermal drilling in the United States has revealed that serious problems are being encountered with corrosion and degradation of drilling fluids in high temperature wells. Viscosity and filtration control problems arise because of thermal degradation of the organic compounds used to control these properties. The high temperature problems are compounded during trips when the mud remains stationary and reaches high temperatures. At the high temperatures the muds tend to solidify causing difficulties in running logging tools to bottom and causing lost circulation problems when running drillpipe into the hole or when resuming pumping after trips.

The best high temperature drilling fluids that could be formulated from commercially available materials were obtained from the five largest mud companies. These included samples of 9 and 18 lb/gal water muds and 18 lb/gal oil muds. Over 4,000 tests were conducted on these muds to evaluate their

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performance at high temperature. This included testing at temperatures to 550°F and pressures to 15,000 psi.

These tests revealed that most of the water muds had high viscosity, high filtration rates and poor corrosivity characteristics at temperatures above 350°F. Although the oil muds performed better than water muds at high temperatures, some problems were encountered with viscosity at temperatures above 450°F and with filtration at temperatures above 500°F. Generally the corrosivity characteristics of the oil muds were much better than those of the water muds. Overall, oil muds have better temperature stability than water muds but their use is often limited because of problems with surface pollution, contamination of water zones and reservoir damage. Biodegradeable oil mud systems would overcome some of these limitations.

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1. *Chlorophyll a* (Chl *a*)

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Introduction

Geothermal wells have been drilled into formations with temperatures in excess of 700°F. Presently used drilling fluids are not capable of maintaining their characteristics at such temperatures. At 250°F, degradation of many constituents of drilling fluids begins and only by systematic replacement of degraded components can present day fluids be used at 400°F. It is felt that no drilling fluid used today can retain the required rheological and filtration control properties above 450°F.

In order to properly develop the many geothermal areas of the United States it is necessary that drilling fluid temperature capabilities be extended. This report is a first step in that direction.

The report discusses geology and drilling in geothermal areas of the United States. Several chapters are then devoted to the state of the art relating to drilling fluid performance at high temperatures. Conditions which exist in the reservoirs are then discussed, and the various properties of the drilling fluids are covered. Three chapters are devoted to describing experimental test results obtained on the drilling fluids submitted by various mud companies. These fluids represent the very best high temperature muds presently available, and yet, most of them are completely inadequate at temperatures above 350°F.

Final chapters include recommendations and engineering alternatives for solving the high temperature problem. Ways are suggested to improve the muds now in use, and the areas of mud technology that need improvements are discussed.

Chapter 1. Functions of Drilling Fluids

Drilling muds serve at least twelve important functions in a drilling operation. These are as follows:

- 1) To transport cuttings
- 2) To control subsurface pressures
- 3) To provide borehole stability
- 4) To cool the bit and lubricate the drill string
- 5) To prevent excessive loss of fluid to permeable zones
- 6) To suspend weight materials and cuttings
- 7) To release sand and cuttings
- 8) To transmit hydraulic energy to the bit
- 9) To provide corrosion protection
- 10) To insure that the required information about the formations penetrated is obtainable
- 11) To provide protection to formation productivity
- 12) To support part of the drill pipe and casing

Cuttings Transport

The primary job of a drilling mud is to remove cuttings from the hole. Once the cuttings are off bottom the mud must transport the cuttings to the surface. The ability of the mud to move cuttings depends partly on the properties of the mud and partly on the circulating rate of the mud. The following factors influence the ability of mud to remove cuttings:

Velocity----Annular velocity, which is the mud velocity between the drill pipe and the wall of the hole, is a significant factor in transporting cuttings to the surface. Velocity is dependent upon pump speed, hole size, and drill pipe size. Increases in the annular velocity will greatly improve the ability of the mud to transport cuttings.

Density-----Drilling mud has a buoyant effect on immersed cuttings; therefore, high density muds have better carrying capacity than low density muds.

Viscosity---Mud viscosity is an important factor in moving cuttings to the surface. If the pump capacity is too low to provide sufficient annular velocity to lift the cuttings, increasing the mud viscosity will improve the lifting power of the mud.

Control of Subsurface Pressures

Another important function of a drilling mud is to prevent the influx of formation fluids into the wellbore. Gas, oil, or water encountered while drilling permeable zones can be controlled by increasing the mud density until the hydrostatic pressure of the mud column exceeds the pore pressure of the formation fluids. Finely ground barite is usually used to increase the density of drilling muds. Limestone, iron oxide, lead sulfide, and salt have also been used in special applications to increase mud density.

The pressure in the wellbore also depends on the dynamic pressures brought about by the circulating mud and by movement of the drill pipe. Dynamic pressures are related to the density and flow properties of the mud.

Borehole Stability

The degree of stabilization which a drilling mud is expected to impart depends on the type of formations encountered. Exposed formations may consist almost entirely of competent sandstones and limestones or they may be predominantly shales. Some shales contain a large fraction of expandable clays. Dispersed, fresh-water muds normally provide an acceptable environment when competent formations are exposed to the mud. Highly bentonitic shale can absorb water, soften, and become incorporated into the mud, thus increasing the viscosity of the mud to unacceptably high levels. Various salts, mixtures of salts and mud additives are used in water muds to inhibit the natural tendency of shale to disperse in the presence of water. Oil muds are sometimes used to stabilize troublesome shales.

Bit Cooling and Drill String Lubrication

All fluids circulated through the drill string cool the bit and most muds provide adequate lubrication to the drill string. Additional lubricity can be obtained by adding

hydrocarbon oils, vegetable oils, asphalt, graphite or extreme-pressure lubricants to muds. Materials described as detergents or surfactants which change the wetting characteristics at the interface between the drill pipe and the well-bore are also added to improve the lubricity of water base muds.

Prevention of Excessive Loss of Fluids

The drilling mud should restrict the passage of fluid into permeable formations and microfractures that are encountered as penetration progresses. A mud with good filtration control characteristics deposits a thin filter cake which impedes the flow of fluid from the mud into permeable zones. The filtration characteristics of a water base mud are improved by adding bentonite or lignitic additives to increase the colloidal fraction of the mud, thinners to disperse the colloidal solids, or organic colloids such as starch and CMC (sodium carboxymethylcellulose). Colloidal materials compatible with oil muds impart similar filtration control characteristics to oil mud systems.

Suspension of Weight Material and Cuttings

During interruptions in drilling operations, mud in the annulus must develop sufficient gel strength to prevent cuttings and weight material from settling to the bottom of the hole. Additions of bentonite or organic colloids are frequently made to increase the gel strength of water base muds. Organophilic clays or soap-type gellants are used to improve the suspension characteristics of oil muds.

Release of Sand and Cuttings

Although it is important to remove cuttings from the hole and suspend them during interruptions in drilling operations, it is also important that the small cuttings, which are not separated by a vibrating screen, be allowed to settle in the settling pit. These seemingly opposite functions are

achieved by careful control of mud viscosity and gel strength along with proper arrangement of the mud pits on the surface.

Transmission of Hydraulic Energy

Each chip which is cut by a tooth of the bit must be moved from the bottom of the hole before the next set of cutters reaches that point in order to avoid having to pulverize each chip. The drilling mud provides the hydraulic impact required to flush cuttings from the bottom and to clean the teeth of the bit.

Corrosion Protection

The drilling mud is expected to inhibit corrosion of tubular goods used while drilling. Additions of caustic soda or lime are made to insure that drilling muds remain alkaline. Various inorganic inhibitors including sodium chromate, sodium bichromate, copper carbonate, zinc oxide, zinc carbonate and iron oxides, as well as the organic filming amines are used to mitigate corrosion from oxygen, carbon dioxide and hydrogen sulfide.

Recovery of Necessary Information

Most of the information about the quantity and type of fluids contained in a reservoir is obtained by logging in the fluid used to drill the well. The drilling fluid should be compatible with the logging system used to evaluate the various formations which are penetrated.

Protect Formation Productivity

Whole mud or mud filtrate can invade a producing formation and can impede the flow of hydrocarbons into the well. Oil muds are used in some areas to keep water out of the producing zones. In other areas various salts such as sodium chloride, calcium chloride, or potassium chloride are added to water muds to minimize formation damage.

Supporting the Drill Pipe and Casing

The drilling mud exerts a buoyant effect on the drill pipe and casing being used. The weight, in air, of casing strings presently being used on deep wells can easily exceed the rated capacity of most drilling rigs.

Chapter 2. Composition of Drilling Fluids

Drilling muds are composed of liquids and solids. The liquid portion may be water, oil, or a mixture of water and oil. The solid portion is usually a blend of commercial clays, barite, polymers, thinners and other chemical additives along with drilled solids.

Most drilling muds are classified as water base muds. In some areas very few problems are encountered and the drilling mud consists of only water and native solids. In other areas it is necessary to add clay to the mud to increase the viscosity and improve the filtration control characteristics of the mud.

Water base muds are composed primarily of three parts:

- 1) The continuous liquid phase, which is water,
- 2) The colloidal fraction, which is the reactive portion of the mud, and
- 3) The inert fraction which consists of barite, sand, and other inert solids.

Oil is easily emulsified into most water muds. When oil is present, the mud is classified as an oil-emulsion mud. The treatment of oil-emulsion mud is the same as that required for water base muds. The major part of mud control is directed toward the colloidal fraction, for this is the portion which contains the bentonites and other clays. This is the part of the mud which is affected by chemical treatment or by contamination.

Clays and Shales

Clays are added to drilling muds to increase the viscosity and gelling character of the mud. The most commonly used clays are the montmorillonites, often referred to as bentonites or

sub-bentonites. Commercial bentonite is not a pure material. It has been estimated that the best material available is about 60 to 70 percent sodium montmorillonite. The remaining portion might be calcium montmorillonite or other low yield clays such as kaolinite, illite or chlorite. Drilled low-yield clays also become incorporated into the mud. Sodium montmorillonite is a plate-like material, which is often compared to a deck of cards. The plates are extremely thin and the total particle may be less than 0.1 micron in thickness.

Salt gel, an attapulgite clay, is used to impart viscosity to salt water. Attapulgite is a needle-like material and does not provide desirable filtration characteristics like bentonite. It does, however, impart a much higher viscosity to salt water than bentonite.

The mechanism by which clays hydrate and swell is believed to be by the adsorption of water on the surface of the clay. The amount of swelling, observed by the measured increase in mud viscosity, that will occur depends on the available surface area and the total amount of water held on the clay. The "yield" of a clay is a measure of the clay's ability to increase the viscosity of fresh water. Yield is defined as the number of barrels of 15 centipoise mud that can be obtained from one ton of the dry clay. Figure 1 shows the viscosity resulting from the addition of various clays to fresh water. A detailed discussion of clay chemistry can be found under the section entitled "Clay Chemistry of Drilling Muds."

High Gravity Solids

Barite is used to increase the density of muds. The primary constituent of barite is barium sulfate. The API Specifications for barite are as follows:

Specific Gravity	4.20, minimum
Soluble Alkaline Earth Metals as Calcium	250 ppm, maximum
Wet Screen Analysis	
Residue on U.S. Sieve No. 200	3.0%, maximum
Residue on U.S. Sieve No. 325	5.0%, minimum

Figure 1. Viscosity of various clays in water¹

The amount of barite needed to effect an increase in the density can be calculated from the following formula:

$$x = \frac{1477 (W_2 - W_1)}{(35.4 - W_2)}$$

where:

x = pounds of barite per barrel of mud
 W_2 = final mud density, ppg
 W_1 = initial mud density, ppg

Various tables are also used to determine the amount of barite required to increase mud density. Figure 2 contains a barite weighting table.

Approximate number of sacks of API Grade Barite to be added to 100 barrels of mud of any weight in order to increase the weight by any desired number of pounds per unit volume.

Pounds Per Gallon

Final Weight Lb/Gal	Sacks Barite Per Lb/Gal Increase Per 100 Bbl Mud	Final Weight Lb/Gal	Sacks Barite Per Lb/Gal Increase Per 100 Bbl Mud
8.5	55.1	14.5	70.6
9.0	56.1	15.0	72.4
9.5	57.2	15.5	74.1
10.0	58.3	16.0	76.0
10.5	59.5	16.5	78.0
11.0	60.6	17.0	80.0
11.5	62.0	17.5	82.3
12.0	63.3	18.0	84.6
12.5	64.6	18.5	87.0
13.0	66.0	19.0	89.6
13.5	67.5	19.5	92.3
14.0	69.0	20.0	95.3

Pounds Per Cubic Foot

Final Weight Lb/Cu Ft	Sacks Barite Per Lb/Cu Ft Increase Per 100 Bbl Mud	Final Weight Lb/Cu Ft	Sacks Barite Per Lb/Cu Ft Increase Per 100 Bbl Mud
67.5	7.50	100.0	8.95
70.0	7.60	102.5	9.09
72.5	7.70	105.0	9.21
75.0	7.80	107.5	9.38
77.5	7.90	110.0	9.52
80.0	8.00	112.5	9.68
82.5	8.11	115.0	9.83
85.0	8.22	117.5	10.00
87.5	8.34	120.0	10.16
90.0	8.45	122.5	10.33
92.5	8.57	125.0	10.52
95.0	8.70	127.5	10.70
97.5	8.82	130.0	10.90

Increase in volume of mud in barrels equals total sacks Barite added, multiplied by 0.0665.

100 sacks of Barite occupy a volume of approximately 6.65 barrels.

Figure 2. Mud weighting tables²

Thinners

As drilled solids become incorporated into the mud, the mud viscosity may become excessively high. Many materials are used to thin drilling muds. These include the following complex phosphates, 1) sodium acid pyrophosphate, 2) sodium hexameta-phosphate, 3) sodium tetrphosphate, and 4) tetrasodium pyro-phosphate, which tend to degrade and lose their effectiveness at 130°F. The phosphates are also ineffective in salty or hard waters.

Lignites and alkaline lignite salts are also effective as mud thinners in fresh water muds. At higher concentrations solubilized lignite acts as a colloid and is not effective as a thinner in salty or hard waters. Lignite is used in formulating most high temperature water base muds.

Another class of fresh water mud thinners is the tannin compounds which include extracts of quebracho, hemlock, redwood and other trees. The tannins are also sensitive to salts and lose their effectiveness in salty or hard waters.

The lignosulfonates are extremely effective as thinners in fresh water muds as well as in salty muds. Many of the ligno-sulfonates can function as thinners in waters saturated with gypsum. At temperatures approaching 400°F most of the ligno-sulfonates are degraded very rapidly, thus losing their ability to thin muds.

Filtration Control Agents

Many materials have been used to supplement clay for controlling filtration in muds. These include the thinners discussed above as well as sodium carboxymethyl cellulose (CM), starches from corn, potatoes and other vegetables, guar gum, xanthan gum, and acrylonitrile polymers.

Specialty Mud Additives

Lost circulation materials are added to muds to minimize the amount of mud lost to the various zones in the hole. The

following substances are added to drilling muds as lost circulation materials: shredded wood fiber, nut hulls, cane fiber, ground flakes of mica, plastic foil, ground leather, cottonseed hulls, newsprint and ground tires.

Improved lubricity is obtained by use of hydrocarbon oils, vegetable oils, asphalt, graphite and extreme pressure lubricants to muds. Many detergents and surfactants are also used to reduce the friction between the drill pipe and the wall of the hole.

Corrosion inhibitors are often used to mitigate corrosion of the drill pipe and casing used in the well. These include lime, caustic soda, sodium chromate, sodium bichromate, copper carbonate, zinc oxide, zinc carbonate, iron oxide and filming amines.

Other specialty mud additives include the following: 1) potassium chloride, calcium chloride, sodium chloride and other salts for borehole stability, 2) aluminum stearate, sulfonated vegetable oils, and alcohols as defoamers, and 3) chlorinated phenols and paraformaldehyde as biocides.

Chapter 3. Clay Chemistry of Drilling Fluids

Anyone concerned with drilling muds is well advised to have a thorough understanding of clay mineralogy and chemistry. Clay provides the colloidal base for the great majority of drilling muds. Moreover, oil wells often must penetrate argillaceous formations, and drilling cuttings therefrom become incorporated in the mud, profoundly changing its properties. And finally, the stability of the borehole depends, to a large extent, on interactions between the mud and exposed shales. In this section, therefore, the essential features of clay technology will be briefly discussed.

Clay Mineralogy

Clays are crystalline minerals which disperse to colloidal dimensions when mixed with water. There are a number of crystal

forms and innumerable variations of each form. Only four clay minerals which are of particular interest to drilling muds will be discussed here:

Montmorillonite -- Wyoming bentonite, which is the clay most frequently used for manufacturing drilling mud, is almost entirely composed of montmorillonite. Also, montmorillonite is the predominant clay mineral in many recent sediments, e.g., the Gulf Coast. At temperatures above $\sim 100^{\circ}\text{C}$ (212°F) under subsurface conditions it undergoes diagenesis to form another clay mineral, illite.

Montmorillonite is a member of the mica type clay mineral group.³ The prototype of this group is pyrophyllite, whose structure is shown in Figure 3. The unit cell consists of a sheet of atoms of Al, Mg, O, OH arranged in an octahedral network, sandwiched between 2 sheets of silica atoms in tetrahedral coordination; the three sheets being held together by shared O atoms. The thickness of the unit cell is 6.6A, and it is of indefinite areal extent. A crystal of pyrophyllite consists of a number of layers of unit cells held together in stacks, like a deck of cards, by van de Waals forces. The distance between a sheet in one layer and the corresponding sheet in the next layer is 9.2A, and is called the C spacing.

Figure 3. Atom arrangement in the unit cell of a three-layer mineral (schematic).³

The atoms in the pyrophyllite crystal, and the analogous mineral talc, are in electrostatic balance, and they therefore do not form colloidal dispersions in water. Montmorillonite is similar to pyrophyllite except that random isomorphous substitutions of divalent atoms of Mg for trivalent atoms of Al in the octahedral sheet, and of trivalent Al for tetravalent Si in the tetrahedral sheet give a negative charge to the particle. To this all-important difference montmorillonite owes its colloidal properties.

The negative charge on the montmorillonite crystal is balanced by the adsorption of counter cations on its external surfaces and between the layers. Because these cations can be exchanged for other cations in the aqueous phase of a montmorillonite suspension, they are called the base-exchange ions. The crystal acts like a multivalent negative radical, and clays with a single species of cation in the exchange positions can be prepared by leaching with a solution of a salt of that cation. Thus it is possible to have sodium montmorillonite or calcium montmorillonite, etc. The amount of exchangeable ions, expressed in milliequivalents per 100 grams of dry clay, is called the base exchange capacity (BEC) and is a measure of the negative charge on the crystal and indirectly of the activity of the clay. Montmorillonite has a high BEC, around 80 meq/100g.

When montmorillonite is contacted with water, or water vapor, water molecules penetrate between the layers, and increase the spacing between the layers. For this reason montmorillonite is said to have an expanding lattice. Up to four monomolecular layers of water can be absorbed in discrete steps, which increases the C spacing to 20A. It is considered probable that the first layer is oriented on the silica surfaces by hydrogen bonding to the oxygen atoms, and its energy of hydration is extremely high. The energy of hydration of the succeeding layers decreases progressively. The high energy of hydration results in the development of very high swelling pressures when dehydrated montmorillonite is contacted with water when constrained (see Figure 4).

Figure 4. Approximate swelling pressures of montmorillonite after Powers⁴

Interlayer hydration is called 'surface hydration,' or '(intra-) crystalline' swelling. With polyvalent cations in the exchange positions it cannot expand the lattice beyond the 20A spacing, and results in no obvious increase in volume, or softening of the clay. With monovalent exchange cations, however, the repulsive forces developed are strong enough to overcome the attractive forces between the layers,⁵ which then readily disperse to single layers. This type of swelling is usually referred to as 'osmotic swelling' because it is controlled by the higher ionic concentration in the vicinity of the clay surfaces relative to that in the bulk of the aqueous phase. Osmotic swelling develops much lower swelling pressures than crystalline swelling, but results in enormous increase in volume when the clay is not constrained, e.g., sodium montmorillonite has been found to absorb 6.52 g water per g dry clay.⁶

Illite -- Illite is perhaps the most common clay mineral in shales penetrated in oilwell drilling. It may be derived in situ from montmorillonite or be of depositional origin.

Illite is a mica-type clay mineral, similar to montmorillonite in structure, except that the lattice substitutions are confined to the silica sheet and the counter cations are invariably potassium. The K ions are the right size to fit the holes in the silica network, and form specific links between atoms in adjoining layers. The bonds so formed prevent the lattice from expanding, and water cannot penetrate between the layers. Hydration and base exchange phenomena are confined to the outer surfaces of the crystal. The base exchange capacity of illite is around 25 meq/100g, and it is much less active in colloidal suspension than montmorillonite.

Kaolinite -- Kaolinite is, like illite, widely distributed among argillaceous sediments, but has a different crystalline structure. It has only two sheets in the unit cell, as shown in Figure 5.

Figure 5. Atom arrangement in the unit cell of a two-layer mineral (schematic)³

There is very little isomorphous substitution in the kaolinite lattice, and the exchangeable ions are held on the outer surfaces only. The base exchange capacity varies between 1-10 meq/100 g and there is, of course, no interlayer hydration.

Attapulгите -- Attapulгите, and the analogous clay mineral sepiolite, have quite a different crystal structure, being needle-shaped instead of platy. Attapulгите is used in brine muds, in which it provides rheological properties by virtue of mechanical interference between the needles. Sepiolite is at present attracting interest because of its resistance to high temperature.

Electro-Chemical Equilibria in Clay Suspensions

The Surface Potential -- The exchangeable cations are attracted to a clay mineral surface by the negative charge on the crystal, but at the same time they have a tendency to drift away. The condition has been compared to the earth's atmosphere, in which the distribution of the molecules in the air depends on the relative forces of gravity and diffusion. A similar distribution of ions prevails in the vicinity of a clay surface, positive ions being in excess near the surface, gradually decrease to neutrality in the bulk liquid. Figure 6 shows such an 'ionic atmosphere' or 'swarm' as it is sometimes called. Figure 7 shows the potential distribution in the ion swarm.

The Positive Edge Theory -- While the surface of the particle carries a diffuse negative charge, there are good theoretical reasons to believe that the edges of a clay particle carry a positive charge, and there is good experimental evidence to support this belief.⁷ The behavior of clay suspensions is now generally explained on the basis that the particles have a moment created by a negative surface and a positive edge.

The Flocculation-Deflocculation Process -- Suspensions of clay in distilled water remain stable indefinitely because of the repulsive negative charge on the particles. If an electrolyte is added in increasing quantities, the ionic swarms at the particle surfaces are increasingly repressed until the particles can approach each other close enough for van der Waal's forces to cause them to agglomerate. In dilute suspensions the particles form loose flocs which slowly settle to voluminous

Figure 6. Diffuse electric double-layer model according to Gouy³

Figure 7. Stern's model of the potential distribution in the electric double-layer³

sediments, leaving a clear supernatant. In concentrated suspensions, such as drilling muds, the particles form a single structure, commonly referred to as a gel, which contracts very slowly, so that it may be days before a layer of clear water appears on the surface. Gel structures are usually explained as

a positive edge to negative face particle association, thus forming a voluminous house-of-cards structure, as shown in Figures 8B and 8D, but this is, of course, a simplification. The particles will agglomerate at angles that depend on the relative positive and negative potentials, and on the concentration of the suspension, but always so as to satisfy the condition of least free energy. Furthermore because of the extreme anisometry of the clay particle, particularly of single units, which are approximately 0.001 micron thick and up to 1 micron in areal extent, they must be conceived of as flexible films (see Figure 9), rather than rigid plates. A bucket full of shredded Saran Wrap would be a better simile than a house-of-cards for a gelled mud.

The critical concentration of salt to cause flocculation depends on the valency of the cation much more than on the species. Approximate flocculation values for monovalent salts are 25-150 millimoles/liter; for divalent salts 0.5 to 2.0 millimoles/liter and for trivalent salts 0.01 to 0.1 millimoles/liter.⁸ For monovalent cations the flocculation values decrease slightly according to the Hoffmeister series:

The Aggregation-Dispersion Process -- The face-to-face association of clay platelets in the form of stacks must be distinguished from the structural association of flocculation because the two modes have opposite effects on the gel strength. As discussed in the last section, flocculation builds a gel structure, but aggregation causes a decrease in gel volume because there are less units to build the structure (Figures 8B and 8D). It is equally important to distinguish a deflocculated suspension of particles dispersed to individual units (Figure 8C) from a deflocculated suspension of aggregates (Figure 8A). Obviously the former will have a much higher viscosity because of the large number of particles and the larger area of charged surface exposed. (Na-montmorillonite has a total surface area of 800 square meters per gram of dry clay.)

FLOCCULATION
DEFLOCCULATION

Ca BENTONITE IN
DISTILLED WATER
Figure 8A

Ca BENTONITE IN
.01 N. CaCl_2
Figure 8B

Na BENTONITE IN
DISTILLED WATER
Figure 8C

Na BENTONITE IN
.1 N. NaCl
Figure 8D

DISPERSION
AGGREGATION

Magnification: 14,800 X

Figure 9. Montmorillonite films

Flocculation depends on the concentration of salts in the aqueous phase, as mentioned above, whereas aggregation depends on the cations in the base exchange positions.

When two or more salts are present in a suspension the cations in the base exchange positions will depend on the relative concentrations of the various cations and their base exchange equilibrium constants, according to the law of mass action.

Aggregation can also be caused by very high concentrations of monovalent salts. For example sodium bentonite aggregates in concentrations of NaCl greater than 400 meq/liter.⁹

Influence on Rheology -- If an increasing amount of a salt is added to a deflocculated mud, the gel strength starts to increase when the flocculation value is reached; rises to a

maximum and then decreases when the aggregation value is reached. This is shown for three simple systems in Figures 10, 11 and 12. (The aggregation value is indicated by the decrease in clay volume and by the increase in optical density in the upper curves.) Note particularly the decrease in both flocculation value and aggregation value with increase in valence of the salt.

Figure 10. Effect of sodium chloride on the optical density, clay volume, and gel strength of sodium bentonite⁹

Figure 11. Effect of calcium chloride on the optical density, clay volume, and gel strength of sodium bentonite⁹

Figure 12. Effect of aluminum chloride on the optical density, clay volume, and gel strength of sodium bentonite⁹

Clays as they occur in nature almost invariably have enough polyvalent cations to keep them aggregated when they are incorporated in a drilling mud, and there is usually enough polyvalent cations in the aqueous phase to provide a moderate gel strength. But gel strengths may become undesirably high as more and more clays are incorporated in the mud by the drilling process, and it is then customary to add a thinner. Thinners are usually the sodium salt of large negative anion, such as a polyphosphate or a tannin. The anion is adsorbed at the edge of the clay particle, neutralizing the positive charge, thus breaking up the gel structure and decreasing yield value and gel strength. But the sodium cation tends to replace the polyvalent cations in the exchange positions, increase dispersion, and hence raise the plastic viscosity. To inhibit this

dispersion, a polyvalent hydroxide, usually $\text{Ca}(\text{OH})_2$, or sometimes a salt such as CaSO_4 , is added to counterbalance the effect of the sodium, thus achieving a deflocculated aggregated suspension. This condition is more usually obtained nowadays by the addition of a lignosulfonate with just enough NaOH to solubilize it, (maximum pH 9.5).

Influence on Filtration Properties -- Clay base muds lay down a filter cake with a remarkably low permeability ($\sim 10^{-3}$ md) by virtue of their flat, platy shape. Dispersion decreases cake permeability, and flocculation increases it. Needle-shaped clays, such as attapulgite, lay down much more permeable filter cakes.

Influence on Hole Stability -- Subsurface clays and shales have been dehydrated by the pressure of the overlying sediments. Drilling a well relieves the lateral pressure and the formation imbibes water from the drilling mud. This change can result in very high swelling pressures which destabilize the borehole. This action can be inhibited by certain clay-base muds, usually containing KCl , or polyvalent cations, to limit lattice expansion, and can be totally prevented by the use of a water-in-oil emulsion whose aqueous phase has a salinity high enough to prevent the uptake of water by the shale.¹⁰ Some oil-base muds contain bentonite with organic radicals instead of inorganic cations in the exchange positions, which makes it possible to disperse the clay in oil.

Effect of High Temperature on Clay Suspensions

The effect of high temperature on clay muds is difficult to predict because of the large number of variables involved, many of them inter-related. Some of the phenomena that may be expected to change the mud properties are:

- 1) Decrease in the viscosity of water, leading to lower mud viscosities
- 2) Development of more disperse ion swarms leading to greater repulsive forces and consequently more dispersion and higher plastic viscosity.

- 3) Above 100°C (212°F) montmorillonite starts to lose crystalline water, resulting in closer C spacing, and greater inter-layer attraction.
- 4) Changes in the base exchange equilibria constants
- 5) Changes in the dissociation constant of weak acids, bases, or salts present in the mud
- 6) Increases in the solubility product of poorly soluble salts. Since these are usually polyvalent salts, this action leads to flocculation and aggregation.

As a result of these variables some muds may thin at first and then thicken as the temperature rises. At a high enough temperature all clay muds flocculate and lose their filtration properties.

Chapter 4. Geothermal Areas of Interest

In any well, the formulation of the drilling fluid will depend on the local subsurface conditions, the lithology of the formations to be drilled, their pore fluids and pressures, subsurface stress fields and temperature gradients. Thus in one locality where the formations are competent, and pore pressures low, it may be found possible to drill with clear water, whereas other localities may require weighted muds with a full range of rheological and filtration control properties. Combating the high temperatures encountered in geothermal drilling will obviously be vastly more difficult and expensive in the latter case.

Our first task therefore is to survey the localities where geothermal wells are at present being drilled, or are likely to be drilled in the foreseeable future, and examine the conditions which will determine the specifications of the drilling fluids.

Localities

The geothermal resources of the United States have been assessed by the Department of the Interior in cooperation with ERDA.¹¹ Table 1, which is reproduced from their report, categorizes the types and conditions of these geothermal

resources. Figures 13, 14, 15, 16 and 17 show the location of these regions. It may be seen that the first two categories -- the hydrothermal convection and the igneous systems -- are located in the western part of the country, which is an area of intense tectonic activity, mountain building and igneous intrusions. The most favorable areas for geothermal exploitation are those where local igneous upthrusts have resulted in temperature gradients as high as 200°C/km ($11^{\circ}\text{F/100 ft}$). Tectonic activity necessarily involves faulting, overthrusting, high earth stress and fractured rocks-conditions which may be expected to give rise to unstable boreholes, and loss of circulation.

The third category listed in Table 1 is the conduction-dominated resource, the prime example of which is the deep geopressured aquifers of the Gulf Coast (see Figure 17). This is a tectonically stable area, except for intrusive salt domes, with very thick tertiary sediments, and temperature gradients up to 37°C/km (2°F/100' , see Figure 18). Drilling conditions in this area are well known from the numerous oilwells that have been drilled there, and are characterized by both normal and geopressured fluid gradients, montmorillonitic shales, and deep, hot, holes.

	<u>Temperature Characteristics</u>	<u>Natural fluid supply</u>
1. Hydrothermal convection systems (relatively high temperatures at shallow depths; heat content estimated only to 3 km depth; see Renner and others, this volume).		
a. Vapor-dominated systems	~240°C	Available; not always adequate.
b. Hot water systems		
(1) High-temperature systems	>150°C	Available; not always adequate.
(2) Intermediate-temperature systems	150°C to ~90°C	Available; not always adequate.
(3) Low-temperature systems (not tabulated; many in Waring, 1965)	<90°C	Available; not always adequate.
2. Hot igneous systems (excluding hydrothermal convection systems in (1) above; heat content estimated from 0 to 10 km depth; see Smith and Shaw, this volume).		
a. Assumed part still molten	>650°C	Inadequate.
b. Assumed not molten but very hot ("hot dry rocks")	<650°C	Generally inadequate.
3. Conduction-dominated areas (by heat-flow provinces, utilizing available data on heat flows, radiogenic heat production, and thermal conductivity of rocks; heat contents estimated for 0 and 3 and 3 to 10 km depth; see Diment and others, this volume. This category includes the Gulf Coast geopressured environment with its fluid fraction specially considered by Papadopoulos and others, this volume).	15° to ~300°C	Adequate in parts of sedimentary basins, generally inadequate elsewhere.

Table 1. Categories of geothermal resource base (heat in the ground at temperatures above 15°C to specified depths and without regard for recoverability¹¹)

Figure 13. Location of hydrothermal convection systems in the conterminous United States with indicated subsurface temperatures above 150°C^{11}

Figure 14. Location of hydrothermal convection systems in Alaska and Hawaii with indicated subsurface temperatures above 150°C (+) and between 90° and 150°C (dots)¹¹

Figure 15. Identified volcanic systems in the conterminous United States¹¹ (Numbers refer to identification of systems in Reference 11.)

Figure 16. Identified volcanic systems (small dots) and basaltic lava fields (+) known to be less than 10,000 years old in Alaska and Hawaii¹¹

Figure 17. Location map showing the extent of the assessed geopressured zones and their division into subareas (AT₃, BT₃, and so on)¹¹

Figure 18. Contour map of geothermal gradients in southwest United States¹²

Chapter 5. Geothermal Drilling Fluids Problems

Geothermal reservoirs may encounter two common troublesome conditions: (1) high temperature and (2) feed in of saline waters and acid gases. These problems produce conditions which can easily destroy the drilling fluid and in some cases destroy the tubular goods by corrosion.

In addition to the above common troublesome conditions each type of geothermal reservoir has its own unique conditions which require unique considerations. Such geothermal reservoirs can be divided into the following types (1) hydrothermal convection systems (2) hot igneous systems (3) conduction-dominated systems.

Troublesome Conditions

High Temperature -- It might be thought that high temperature stability would be the one problem common to all categories of geothermal exploitation. This is not strictly so, however, because as shown in Table 2, hot water resources having temperatures up to 150°C (300°F) are used for space heating and are included in the U.S. resources base.¹³ Many types of drilling mud are stable up to 150°C. There should be no temperature related problem in drilling wells in this category, so there will be no further discussion on this subject in this report. With temperatures above 150°C, mud stability becomes a major problem, and an intractable one at the temperatures above 200°C. It is necessary, therefore, to discuss in some detail the effect of high temperature on drilling muds.

Water-base muds start to degenerate significantly at about 150°C and the rate of degeneration increases rapidly with increase in temperature. Fundamentally the problem arises because the clay colloids flocculate giving rise to high shear strength and gel strength (See Figures 19, 20 and 21). The gel strengths can be reduced by the addition of lignosulfonates but unfortunately these start to degrade at about the same temperature, and are virtually useless at temperatures above 190°C (375°F). At temperatures above 250°C severe corrosion problems

are encountered. The flocculation of the clay also makes it difficult to control filtration rates, and filtration control agents, such as carboxy methyl cellulose, also start to degrade rapidly at 150°C. The higher the proportion of solids in the mud, particularly the clay fraction (see Figure 22), the more sensitive the mud becomes to high temperature flocculation. The presence of salts, even in small quantities, causes further sharp increases in shear and gel strengths (see Figures 23 and 24).

With unweighted muds the problem can be handled to a limited extent by watering back and replacing the degraded treating agents with fresh materials. This is expensive however. The use of mechanical separators (such as fine screens and cyclone separators) to remove drill cuttings and dispersed particles in order to keep the solids content as low as possible is also beneficial.

With weighted muds the problems are much more severe. The barite itself greatly increases the solids content of the mud, making rheological control much more difficult. In order to remove drilled solids without removing the barite, a power driven centrifuge is necessary; centrifuges are expensive and only handle a small fraction of the mud stream. Watering back is also very expensive because of the fresh additions of barite required to restore the density; worst of all, if the mud becomes contaminated, for example, by a salt water flow, the resulting high gel strengths, or thick filter cakes on permeable strata, may cause the drill pipe to stick, which will entail an expensive fishing job, or even loss of the well.

Because of these difficulties, the limiting temperatures for water base muds is generally considered to be about 190°C (375°F), although some products, now being developed, which are discussed later in this report, show promise of extending the range further.

Oil base muds are more stable, and some of them withstand temperatures up to about 250°C (475°F), but oil muds are not considered suitable for geothermal drilling because contamination of the aquifer by oil would decrease productivity. Furthermore,

Figure 19. Effect of temperature on initial and 30 minute gel strengths¹⁴

Figure 20. Effect of time and temperature on gel strength¹⁴

Figure 21. Effect of hot rolling on shear rate -- shear stress relationship¹⁴

Figure 22. Effect of temperature and bentonite concentration on 30 minute gel strength¹⁴

Figure 23. Effect of electrolytes on shear rate -- shear stress relationship¹⁴

Figure 24. Effect of electrolytes on shear rate -- shear stress relationship¹⁴

most operators are hesitant to use oil base muds because of the possibility of environmental damage resulting from spills, separator discharges, or blowouts.

It is important to note that the limiting temperatures quoted above are well below the maximum formation temperature while the mud is circulating. This is because the mud cools the formations at the bottom of the hole, and transfers the heat to the cooler formations above and to the atmosphere at the surface. When circulation is stopped the temperature of the mud rises towards equilibrium with the formation (see Table 2), but does not have time to reach the undisturbed geothermal gradient during normal drilling operations. The principles involved have been shown in a theoretical calculation by Raymond, and are illustrated in Figures 25-28.

Conditions in geothermal wells may be different from those postulated by Raymond. Temperatures may be higher, and they occur at shallower depths. In Raymond's example the bottom hole formation temperature was 204°C (400°F) at a depth of 6.1 km (20,000 ft), whereas in a geothermal well temperatures as high as 350°C (660°F) have been encountered at a depth 1.5 km. Because of the shallow depth, the rising column of mud has little time to cool before it reaches the surface, and because of the low head of fluid above it, it may boil before it gets there. This is illustrated in Figure 29, which shows the boiling point of water versus its vapor pressure and the corresponding height of the column of water required to equal the vapor pressure. Also shown are the hypothetical temperatures of a circulating column of water, which boils at the intersection of the two curves. Boiling may be prevented by three methods, or any combination of same:

- 1) Cooling the mud at the surface so that temperatures throughout the whole circulating system are lowered sufficiently.
- 2) Holding a back pressure at the surface, and flashing the mud in a separator
- 3) Increasing the density of the mud.

Well no.	Circ. depth	Bomb depth	Mud wt & type	Circ. rate, bbl/min	Static period, hr	Circ. time	Max. temp.	Circ. temp.	ΔT	Temp. gradient
1	7,215	7,215	10.2 W	7.6	23	2:30	172	148	24	1.34
2	13,083	13,083	W	4.3	42	3:30	229	149	80	1.18
		11,083					190	162	28	1.04
3	18,000	18,000	17.2 O	3.2		4:00	412	360	52	1.87
		15,500					368	345	23	
		7,890					217	225	(7)	
4	9,160	9,160	12.5 W	9.5		3:00	199	152	47	1.35
		8,200					188	160	28	
5	8,030	8,030	10.5 W	6.0		4:00	207	147	60	1.65
		5,315					161	147	14	
		2,320					125	128	(3)	
6	12,340	12,310	9.5 W	8.0		3:00	239	191	48	1.33
		9,940					204	192	12	
		7,540					185	179	6	
7	9,318	9,308	12.5 W	5.6		3:00	196	153	46	1.30
		6,527					175	150	25	
8	19,852	19,850	17.8 O	N.A.		4:00	401	351	50	1.65
		12,000					284	282	2	
9	22,725	22,725	10.5 W	4.8		4:00	333	295	38	1.14
						5:00		286	47	
10 a	12,180	12,180	16.8 O	5.0		4:00	312	212	91	1.95
b	13,902	13,902	18.5 W	4.0		2:30	414*	294	120	2.44*
11	11,470	11,450	13.4 W	5.6	23.8	2:15	232	197	35	1.37
12	16,000	15,520	12.4 W	5.3		4:00	350	295	55	1.72
13	14,665	14,665	W	4.0	14.5	2:05	369	332	37	2.00
14	13,875	13,875	W	6.7	26.5	4:00	260	217	43	1.33
		12,875					247	197	50	
15	11,340	11,340	W		32.5	2:30	262	210	52	1.65
		9,340					223	203	20	
16 a	12,294	12,294	16.7 W	4.7		4:00	325	250	75	2.03
b	11,356	11,356	16.7 W	5.1		2:30	290	235	65	1.89
c	10,424	10,424	16.7 W	5.0		2:30	275	220	55	1.92
d	5,500	5,500	16.7 W	5.0		1:30	182	148	34	1.95
e	16,035	16,035	17.8 O	3.8	68.0	4:00	364	285	79	1.81
f	12,291	12,291	17.8 O	3.8		2:00	318	233	85	1.98
g	10,424	10,424	17.8 O	3.5		2:00	290	200	90	2.06
h	5,520	5,520	17.8 O	3.8		2:00	202	146	56	2.31
17	13,640	13,540	10.9 W	10.0	32.5	3:00	223	177	46	1.1
		10,540					187	169	18	
18	11,920	11,920	13.8 W	9.65	16.5	3:00	185	166	19	0.92
19	16,300	16,300				4:00	315	292	23	1.47
		14,995	18.9 W	3.3			299	290	9	
20	13,037	13,037	14.0 W	6.4		4:00	260	211	49	1.42
		10,451					229	209	20	
		3,903					159	162	(3)	
21	15,000	15,000	18.2 W	6.2		4:00	296	254	42	1.35
		14,009					275	254	21	
		10,005					227	224	3	
22	15,000	14,965	18.5 W	4.0		4:00	313	291	22	1.53
		12,177					265	266	(1)	
23	17,410	17,310	16.3 W	6.8	33	3:00	227	189	38	.83
		12,235					159	158	1	

(* Est.)

Table 2. Circulating temperature data¹⁴

Figure 25. Effect of time on temperature in a simulated well¹⁴

Figure 26. Circulating fluid system model¹⁴

Obviously method 1 is to be preferred, because it has the additional advantage of making the control of the mud properties much easier. However, it is inoperative during round trips to change bits, etc., and there is the danger of a blow-out when circulation is resumed, and the hot mud from the bottom is carried up the hole. It therefore must be used in combination with method 2. Method 3 is the least desirable, and should be avoided if at all possible, because it increases the difficulty and expense of controlling the other properties of the mud.

Figure 27. Temperature trace for various depths in a simulated well¹⁴

Figure 28. Percent of fluid above a given temperature versus temperature¹⁴

Because of this gap between the mud and the formation temperatures it has been found possible to maintain adequate mud properties with formation temperatures of 350°C (660°F). In the Salton Sea area, for example, formation temperatures of this order are encountered, but bottom hole mud temperatures have been found to be only about 250°C (450°F) after an eight hour shut down. Cooling towers are required on the extremely hot wells to keep the muds in usable condition.²⁵ Nevertheless, mud costs are high and there is always the danger that the mud will break down completely should circulation be shut-down for a prolonged period, say during a fishing job or during completion operations.

There is therefore a need to develop more thermally stable water-base drilling fluids, but it is hardly necessary to point out that the maximum temperature for water-base muds is 374°C (704°F), i.e., the critical temperature of water, or a little higher if the mud contains dissolved salts. But it is likely that the electrochemical equilibria, which govern the behavior of the mud, will be sufficiently upset at temperatures well below the critical as to make the use of water-base muds impracticable. For higher temperatures, therefore, entirely new non-aqueous muds systems are necessary.

Salts and Acid Gases -- The only other deleterious condition common to all types of geothermal reservoirs is the presence of salts and acid gases. Salts cause clay-base muds to flocculate, with consequent high gel and shear strengths, and loss of filtration control. In moderate amounts and at low temperatures these difficulties can be overcome by the use of deflocculants and filter loss control agents, but, as pointed out above, these agents degrade at high temperatures.

Salts and acid gases, particularly the latter, cause corrosion, which is accentuated at high temperatures. Hydrogen sulphide poses a particularly severe problem. The experience of the Shell Oil Company with deep gas wells in Mississippi, where the gas contained 27-46% H₂S at temperatures up to 197°C

Figure 29. Vapor pressure and equivalent head of water vs temperature (Dashed line shows hypothetical temperatures of water circulating in a well of 1600m depth, and undisturbed formation temperature of 340°C. Under the assumed conditions water would boil at a depth of about 300m.)

(385°F), showed the need for more corrosion resistant casing and tubing than is presently available.¹⁵ Drilling muds must have sufficient alkalinity to neutralize acids from dissolved gases, and must contain scavengers when H₂S is present. Because of the high toxicity of H₂S, stringent safety precautions must be taken, particularly with blow-out preventers and the training of crews in the operation thereof.

Drilling Fluid Conditions Unique to Particular Types of Geothermal Reservoirs

Hydrothermal Convection -- In hydrothermal convection systems heat is carried upwards by circulating fluids rather than by conduction through solid rock. Typically they consist of an aquifer overlying an upthrust of hot igneous rock (Figure 30). Water, circulating by convection in the permeable aquifer, carries the heat from the underlying hot rock to the top of the reservoir. This process results in very high temperatures at shallow depths, e.g., the Salton Sea area, mentioned above, where temperatures up to 350°C (660°F) are found at depths of only 1500m, or so.

The aquifer is capped by a low permeability rock but some water rises upwards by diffusion, and through vents and open fractures, to the surface where it forms hot springs. If this loss of water from the reservoir can be replaced by water from external sources the result is a "water-dominated hydrothermal reservoir" which produces mostly hot water and a small amount of steam, (e.g., the Salton Sea area). If the external water supply is not adequate, the water level in the aquifer falls (e.g., the geysers in California).

The presence of volcanic formations, or the degradation products thereof can cause various problems, e.g.: tuffs (pumice) are highly abrasive and causes excessive wear of equipment. Bentonite, which is a degradation product of volcanic ash is likely to be encountered in the northwest United States, and in Alaska. It is a highly active clay, which swells and sloughs into the borehole when contacted by water. Greenstone,

Figure 30. Model of a high-temperature hot-water geothermal system. Curve 1 is the reference curve for the boiling point of pure water. Curve 2 shows the temperature profile along a typical circulation route from recharge at point A to discharge at point E.²³

an alteration product of granite,¹⁶ is commonly found in California. It is not an active shale like bentonite, but is friable and caves easily causing hole enlargement and increasing the solids content of the mud.

Another common problem is loss of circulation into highly porous beds, or open fractures associated with the tectonic disturbances and high temperatures. Drilling fluid will be lost in bulk into these openings if the pressure of the mud column exceeds the pressure of the fluid in the pores of fractures, and if the mud does not contain particles of a size large enough to bridge them. The consequent loss of hydrostatic head may result in a blow-out.

In water-dominated geothermal areas the pressure of the fluid in the fractures will be governed by the normal hydrostatic gradient, probably somewhere between .08 and .1 kg/cm²

(.35 - .44 psi/ft) depending on the level of the water table. In vapor-dominated areas the pressure will be governed by the vapor pressure gradient in the fracture, which will depend on the vapor pressure at the water level in the reservoir and whether and how freely the fracture is vented at the surface. In the Geysers field the reservoir temperature is 240°C and the pressure 35 kg/cm² (497 psi).

Drilling Fluid Requirements for Hydrothermal Reservoirs:

150°C - 375°C -- For water-dominated reservoirs low weight brines would be adequate to control formation pressures and could be used whenever a gauge hole can be maintained. But because of the prevalence of friable shales and fractured rocks in these areas and the consequent likelihood of hole enlargement, it will usually be found necessary to provide rheological properties to lift the drill cuttings, and filtration properties to control caving. At present bentonite is used to obtain these properties, but excessively high shear and gel strengths are experienced when the bentonite flocculates as the mud temperature increases with depth. Lignite in a combination with NaOH and a proprietary surfactant known as DMS (a non-ionic-30 mol ethylene oxide (C₆H₅-O-(CH₂O)₃₀H)⁵ are used to control flow properties; the lignite also helps provide filtration control. In some areas where caving shales are a severe problem, the use of the recently developed potassium-lignite¹⁸ mud might be justified.

The key to combating the effects of high temperatures on drilling muds in these wells will be the maximum use of high capacity cooling equipment at the surface. Heat exchangers specially designed for geothermal drilling are being built but are not yet available.

To lessen the possibility of loss of circulation, the mud density should be kept to the minimum necessary to control formation pressures. In areas where the formation pressure gradient is subnormal, the density of the mud may be lowered by continuously injecting air. The use of desanders and desilters will lessen density increases caused by the incorporation of drilled solids, but, on the other hand, the large size

particles are necessary to bridge across minor fractures, and hence their removal increases the possibility of losing circulation. If loss of circulation does occur into large fractures or openings it is best cured by the addition of properly graded granular material (e.g., walnut shells, or ground limestone), with a maximum particle size approximately equal to the width of the fracture. The maximum particle size necessary can only be determined by trial and error or by previous experience in the area.

Since loss of circulation into a reservoir may greatly reduce future production from that reservoir, everything possible should be done to avoid such loss. This is best done by drilling into the reservoir with a balanced or underbalanced mud column, using pressure control equipment at the surface.

The only significant difference relevant to mud control, between water and vapor-dominated reservoirs is the very low formation fluid pressures in the latter. This makes it difficult to prevent loss of circulation if open fractures are encountered unless air or foam are used as the circulating medium. However, these fluids exert little pressure on the borehole walls, and hence borehole stability becomes more of a problem. For this reason it is probably best to use drilling mud as long as possible and only switch to air or foam if loss of circulation becomes a problem. In any event it is advisable to use the latter when drilling into the reservoir.

Hot Igneous Systems

Hard Rock 150°C - 650°C -- This system is referred to as the 'hot dry rock' because there is no overlying aquifer, and the igneous rock itself is the heat reservoir. It does not contain sufficient water or have sufficient permeability to permit the withdrawal of water. It may be expected to be hard, massive rock, but might contain open fractures at shallow depths (Figure 31).

Figure 31. Hot dry rock geothermal system¹⁹

Drilling conditions in the sedimentary strata overlying the igneous rock may be expected to present the same kind of drilling problems as discussed under hydrothermal systems, and require the same kind of muds. In the igneous rock itself, stable borehole conditions are likely and the principal problem will be slow drilling rates and bit and drill pipe wear by the hard abrasive rocks. Loss of circulation with liquid muds would be a problem if open fractures were present, especially when the fluid pressure gradient is subnormal, (the water table in an

experimental hot rock well drilled in the Jemez plateau by the Los Alamos Laboratory encountered the water table at a depth of 533m (1750').¹⁹

Maximum drilling rates will be obtained by drilling the igneous rock with air, but it may be preferable to use clear water with a high pressure lubricant to cool and lubricate the pipe and bit bearings, and to reduce the number of trips required to change bits. In order to maintain as fast a drilling rate as possible with water, all drilled solids must be removed at the surface, which should be no problem when drilling hard, non-dispersing, igneous rocks. Obviously the upper part of the hole should be cased off before switching to air or water.

The use of air or water would eliminate the problem of high temperature degradation of mud components and raise the limiting temperature for geothermal drilling. For fluid temperatures above the critical, air or aerosols should be considered. The limitations on their use would likely be hole diameter, depth, strength of the rocks at that depth and temperature.

Igneous Rock > 650°C -- It is expected that igneous rocks will be at least partly molten at temperatures above 1100°C (see Table 2). Such rocks down to a depth of 10 km are considered part of the U.S. resource base. Theoretically the pressure of the magma should equal the pressure of the overlying rocks ($.223 \text{ kg/cm}^2/\text{m} = 1 \text{ psi/ft}$).

Drilling under such conditions would involve difficulties far above present technology, and will not be discussed further in this report.

Conduction-Dominated Systems

In this section we will consider only the geopressured watersands of the Gulf Coast, which are the only geothermal resource included in this category in the 1975 assessment (see Table 2). A great deal of information on drilling conditions is available from the numerous oilwells that have been drilled in this region, to depths up to 4 km (23,000'). Geopressure

gradients are usually over .18 kg/cm²/m (.8 psi/ft), and are sometimes as high as .22 kg/cm²/m (.99 psi/ft). Temperatures up to 275°C (527°F) have been encountered. A typical cross-section is shown in Figure 32.

Mud problems related to these conditions are:

- 1) The Miocene sediments in the upper part of the hole contain montmorillonitic shales, which swell and slough into the hole.
- 2) Salt (halite) domes or beds, may flow plastically, restricting hole diameter, or may be dissolved by the mud, causing hole enlargement. Caving of shattered shales associated with salt domes often causes drilling problems.
- 3) Loss of circulation caused by induced fracturing. This occurs when the pressure exerted by the mud column on the borehole walls exceeds the least horizontal earth stress. This condition occurs when:²¹

$$P_m > \frac{1}{3} (S-P) + P$$

where P_m is the pressure of the mud, S is the overburden (lithostatic) pressure, $\sim .223$ kg/cm²/m (1 psi/ft) and P is the pressure of the fluid in the formation. Typically the problem arises when formations with normal and geopressure gradients are exposed at the same time; the high density mud required to control the geopressures induces a fracture in the low pressure formation. This problem can only be overcome by separating the zones with casing. Electric logs, shale density logs, or changes in drilling rate are used to determine the boundary between the zones.

- 4) High viscosities and gel strengths caused by the high temperatures in the deeper formations. Most operators drill as deep as they can with water-base muds, but the problems associated with thermal degradation of mud components, high solids contents resulting from dispersive shales and the high barite content, which were discussed earlier in this report, usually force them to finish deep holes with oil-base muds.
- 5) Deep Holes -- the difficulties and costs of drilling increase sharply with depth because:
 - a. Drilling rates are slower, and trip times longer.
 - b. Higher formation temperatures
 - c. Although the longer circulation times permit more heat transfer from the ascending mud than is the

Figure 32. Typical geopressured Gulf Coast watersands²⁴

- case in the shallow hydrothermal wells, the longer trip times result in higher static mud temperatures.
- d. Casing programs are more costly because more strings and liners are required, and strength requirements are high.
 - e. Deep drilling requires large, more expensive rigs.

Oilwells drilled to 9000m (30,000') in the Gulf Coast area are straining the limits of existing technology. Geothermal wells will encounter the same conditions, and have the additional difficulties:

- 1) Oil-base muds will be undesirable because of contamination of the aquifer.
- 2) Larger hole and casing sizes will be required to handle the large volumes of hot water to be produced. This will add considerably to the cost, and in very deep holes, there will be problems designing large diameter casing strings of sufficient strength. Technically the latter problem could be overcome by spacing the wells closer than reservoir engineering would otherwise dictate.

Conclusions

- 1) Drilling conditions in the hydrothermal convection regions require unweighted muds, with rheological and filtration control. Wells are at present being drilled in these regions with such muds but with some problems and at high cost.
- 2) Better water base muds that will withstand temperatures approaching the critical for extended periods of time are desirable. Similar muds are required for geopressure drilling in the Gulf Coast except that specific gravities up to 2.3 (19 ppg) are necessary, and maximum temperatures are lower, at least for depths above 7000m (23,000 ft).
- 3) Water, air or aerosols can be used to drill hot igneous rocks at least under some conditions. The limits to which they can be used have yet to be determined.
- 4) Oil-base muds can be used at higher temperatures than water-base muds but are undesirable due to contamination and formation damage.
- 5) Water-base muds degrade severely above 200°C (392°F).

Chapter 6. Geothermal Drilling Fluids Test Procedures

Laboratory tests were set up to evaluate the temperature limits of various drilling fluids recommended for high temperature wells. These tests consisted of dynamic tests, static tests and corrosivity tests.

Test Temperatures

Test equipment usually used in mud testing is normally calibrated in degrees Fahrenheit. Also, test procedures outlined in the American Petroleum Institute Bulletin RP-13B specify test temperatures (such as in the high temperature filtration test) in degrees Fahrenheit. For these reasons the data obtained in this study are reported using the Fahrenheit scale and not the centigrade scale. The Fahrenheit values reported can be converted to centigrade using the equation $^{\circ}\text{C} = (^{\circ}\text{F} - 32) \div 1.8$ or the table

<u>Degrees Fahrenheit</u>	<u>Degrees Centigrade</u>
350	177
400	204
450	232
500	260
550	288

Dynamic Tests

The dynamic tests consisted of placing a sample of the mud to be tested in a steel container, then rolling the container in an oven at 350°F and 300 psi nitrogen pressure for a fixed period of time. The mud sample was then removed and various mud properties measured. The rolling dynamic test was felt to represent typical conditions acting on a mud while it is being circulated. These tests were run for periods of 8, 16, 40 and 64 hours.

Static Tests

A second test, the static aging test, was run to evaluate the performance of the muds under non-circulating conditions.

In a typical drilling operation it is necessary to stop circulation of the fluid for periods up to 24 hours, as the pipe is removed from the hole and the drill bit is changed. During this period of time the drilling fluid at the bottom of the hole experiences higher temperatures and in many cases becomes degraded to the extent that it is unpumpable. Static tests were run for 24 hours under conditions of (2) 450°F - 300 psi (b) 500°F - 375 psi (c) 500°F - 15,000 psi and (d) 550°F - 500 psi.

Corrosivity Tests

Corrosion tests were run on test coupons placed in the various muds and tested under both dynamic conditions at 350°F and static conditions at 450°F, 500°F and 550°F. Such tests were intended to help evaluate the corrosive tendencies of the fluid under high temperature conditions after sample degradation has occurred.

Two types of corrosion coupons were used, a flat metal plate 1" x 3" x 1/16" made of mild steel and a roller bearing made of solar steel (R_c 55-57) which had been stressed by yielding the metal with a 30,000 lb load. Two teflon "O" rings were used to isolate areas on the prestressed roller bearings. The flat metal plate reflected the corrosion rate (mils per year), the type of corrosion (whether generalized or pitting), and the presence of iron sulfide. The prestressed roller bearings reflected the tendency of the mud to produce hydrogen embrittlement.

Muds Tested

Three types of drilling fluids were tested; a 9 ppg water mud, an 18 ppg water mud and an 18 ppg oil mud. One sample of each was received from the following mud service companies; IMCO Services, Magco-bar Division of Dresser Industries, Milchem Incorporated, NL Baroid Petroleum Services, and Oil Base Incorporated. The submitted samples were designed to withstand the extreme temperatures usually encountered in geothermal wells.

Composition and price of each sample is given in Tables 3, 4 and 5. The source of each sample was intentionally withheld from the report at the request of the various service companies involved.

Mud	Cost, \$/bbl.	Composition
A	11.35	Sodium bentonite Calcium bentonite Modified lignite Sodium carboxymethylcellulose Sodium hydroxide
B	18.00	Sodium bentonite Modified lignite Polymer Sodium hydroxide
C	6.95	Sodium bentonite Shale Lignite Modified lignite Sodium hydroxide Sodium carbonate Sodium chromate
D	13.05	Sodium bentonite Chrome lignosulfonate Modified lignite Sodium hydroxide Divalent salts Asphalt Diesel oil
E	7.50	Sodium bentonite Sepiolite Polymer Sodium hydroxide

Table 3. Mud compositions and cost of 9 ppg water muds

Mud	Cost, \$/bbl.	Composition
F	41.78	Sodium bentonite Calcium bentonite Asbestos Modified lignite Sodium hydroxide Sodium carboxymethylcellulose Barite
G	42.96	Sodium bentonite Sodium chloride Modified lignite Asphalt Barite
H	40.00	Sodium bentonite Chrome lignosulfonate Lignite Polymer Sodium chromate Barite
I	37.00	Sodium bentonite Chrome lignosulfonate Modified lignite Polymer Sodium hydroxide Barite
J	43.78	Sodium bentonite Shale Lignite Modified lignite Sodium hydroxide Sodium carbonate Sodium chromate Barite Surfactant Polymer

Table 4. Mud composition and costs of 18 ppg water muds

Mud	Cost \$/bbl.	Composition
K	63.00	Fatty acid salt Amine derivative Oil dispersible polymer Organophilic clay Calcium chloride Diesel oil Barite
L	63.80	Emulsifier Surfactant Fluid loss reducer Calcium oxide Calcium chloride Diesel oil Barite
M	58.98	Asphalt Calcium hydroxide Fatty Acids Surfactant Diesel oil Barite
N	93.20	Emulsifier Organophilic clay Fluid-loss Reducer Calcium chloride Diesel oil Barite
O	48.31	Emulsifier Fluid-loss Reducer Surfactant Lime Shale Diesel oil Barite

Table 5. Mud composition and costs of 18 ppg oil muds

Chapter 7. Dynamic Testing of Geothermal Drilling Fluids (350°F)

Summary

Of the fifteen muds subjected to dynamic rolling only one 9 ppg (pounds per gallon) water mud and one 18 ppg oil mud had good viscosity and filtration control characteristics. The properties of one oil mud and three water muds were marginal and the remainder of the muds were considered to have excessive viscosity or filtration.

Experimental Procedure

Three mud samples, typical of their best high temperature muds, were submitted by each of five independent mud companies for evaluation before and after aging. Aging consisted of placing 350 ml of mud in a pressure vessel, then "rolling" the mud in an oven at 350°F after pressuring the vessel to 300 psi with nitrogen. After a fixed period of time (8, 16, 40 or 60 hours), each sample was removed, cooled to 125°F, then its various properties measured. A tabulation of all results obtained is given in Data Sheets 1-15 in Appendix A. The properties studied consisted of the mud's density, pH, plastic viscosity, yield point, gel strengths, API and high temperature-high pressure filtration characteristics. In order to provide detailed description of the rheology and fluid loss characteristics of the muds tested, a six speed rheometer was used and long time (180 min) high temperature-high pressure filtration tests were run at 350°F with a differential pressure of 500 psi.

Of the many properties studied only two, the yield point and the high temperature-high pressure (HT-HP) filtration characteristics, will be used in this chapter to display the rate of degradation of the fluids studied. In drilling fluid testing these two properties are usually used to display sample degradation. For a 9 ppg water mud the yield point should range from 2 to 8 lb/100 sq ft and the high temperature (350°F) - high pressure (500 psi) filtrate (HTHP) should not exceed 25 ml after 30 minutes.^{26, 27}

Test Results - 9 ppg Water Muds

All 9 ppg muds tested, except mud E, had an increased yield point after rolling. The dynamic tests also accelerated the filtration rate of each mud except mud D. Of the five muds tested two exceeded the yield point specifications and four exceeded the filtration specifications.

Viscosity

As shown in Figure 33, muds A, B, C, and D were thicker (a higher yield point) after being hot-rolled than when tested initially. As listed in Data Sheets 1-5 of Appendix A the apparent viscosity and plastic viscosity also increased with exposure time. Mud E was much thinner after being hot-rolled than when tested initially as indicated in Figure 33. Such excessive thinning (see Data Sheet 5, Appendix A) produces a fluid which has low gel strength and therefore has poor barite suspension qualities.

Only muds C and D would be acceptable, from a yield point consideration, for circulating at 350°F for extended periods of time.

Filtration Control Characteristics

Figure 34 shows that the muds had HTHP Filtrates ranging from about 16 to 34 ml before hot-rolling which increased to about 20 to 50 ml after hot-rolling. In general, prolonged aging caused degradation of the mud under the test condition of 350°F as indicated by an increased HTHP Filtrate.

After testing muds A, D and E had unacceptably high HTHP Filtrates. Mud B had a filtrate which was only marginal. Such high fluid losses would produce excessive filter cakes which might result in differential pressure sticking of the drill pipe. The fluids loss of Mud C increased slightly with heat aging, however its fluid loss did not exceed the 25 cc maximum allowed.

Figure 33. Yield point of 9 ppg water muds after rolling at 350°F - 300 psi

Figure 34. HTHP Filtrate of 9 ppg water muds after rolling at 350°F - 300 psi

Test Results - 18 ppg Water Muds

All 18 ppg water muds had higher yield points or fluid losses after hot-rolling of the five 18 ppg muds tested, two had acceptable filtration control (muds H and J) and all five showed signs of excessive thickening with time.

Viscosity

As shown in Figure 35 the yield point of all muds increased excessively when subjected to hot-rolling conditions of 350°F and 500 psi.

Mud sample G was settling initially, but thickened with increased exposure time at 350°F. Sample H had high viscosity, initially, and became extremely viscous after hot-rolling at 350°F. Fann V.G. meter readings of greater than 300 (maximum obtainable with a one multiplier spring) were obtained on sample h after hot-rolling at 350°F - 500 psi for 16 hours and longer. The remaining muds fell between the extremes represented by muds G and H.

Such mud thickening would suggest that none of the five muds would be suitable for prolonged circulating at 350°F.

Filtrate Control Characteristics

Mud J had the lowest HTHP Filtrate of any of the 18 ppg water muds tested, namely 5.6 ml (see Figure 36). The filtrate remained at this acceptable level even after 64 hours of exposure to 350°F in hot-rolling tests.

Samples F, H and I had acceptable filtrates of 10 ml or less, initially, and sample G did not. The filtrates of mud samples F and H increased gradually with increased exposure time at 350°F. Mud sample I showed evidence of having been severely degraded after exposure to 350°F, since the HTHP Filtrate increased from 10.0 ml to 51.4 ml after rolling 64 hours at 350°F - 300 psi.

**O.S. - OFF SCALE AT 600 RPM ON A FANN
VG METER (ONE MULTIPLIER SPRING)**

**▨ YIELD POINT OF MUD BEFORE
ROLLING AT 350°F**

**Figure 35. Yield point of 18 ppg water muds after rolling at
350°F - 300 psi**

**HTHP FILTRATE OF MUD
BEFORE ROLLING AT 350°F**

Figure 36. HTHP filtrate of 18 ppg water muds after rolling at 350°F - 300 psi

Test Results - 18 ppg Oil Muds

All oil muds had excellent filtration control after hot-rolling at 350°F - 500 psi but only two muds did not thicken excessively.

Mud Viscosity

Generally, the weighted oil muds were much thicker than the weighted water muds when tested initially. Muds K, L, and M were even thicker after being hot-rolled at 350°F as shown in Figure 37 by yield point measurements at 125°F. All of these hot-rolled muds were off scale at 600 rpm on a Fann V.G. meter equipped with a 1 multiplier spring. Mud K was off scale at 100 rpm and mud N was off scale at 200 rpm after rolling 64 hours at 350°F - 500 psi. The gel strengths of muds K and M increased with increased exposure time at 350°F, while those of mud M decreased with increased exposure time at 350°F.

Muds N and O had much better yield point characteristics after being exposed to 350°F - 500 psi than the previously mentioned muds. Mud N had an increase in plastic viscosity and a decrease in yield point with increased time at 350°F while mud O showed a reduction in both plastic viscosity and yield point with increased time at 350°F. These two muds would be considered acceptable for prolonged circulating at 350°F.

Filtration Control Characteristics

All of the oil muds had excellent filtration characteristics, initially having zero API Filtrates and having a filtrate of 2.5 ml or less of oil in HTHP filtration tests. None of the muds filtered water.

The API filtration tests (see Appendix A) show mud K to filter a small amount of oil and muds L, M, N and O to have zero API Filtrates. Such low filtration is typical of all good oil muds. This is one of the main reasons why oil muds are used in high temperature drilling.

Emulsion stability was excellent in all of the muds as indicated by high electrical stability readings initially and after rolling at 350°F.

Figure 37. Yield point of 18 ppg oil muds after rolling at 350°F - 300 psi

Figure 38. HTHP Filtrate of 18 ppg oil muds after rolling at 350°F - 300 psi

Conclusions

- 1) Of the fifteen muds subjected to dynamic rolling only one 9 ppg water mud and one 18 ppg oil mud had good viscosity and filtration characteristics. These were muds C and O respectively.
- 2) The properties of one oil mud (mud N) and three water muds (muds B, D and F) were marginal and the remainder of the muds were considered to have excessively high viscosity or filtration.

Chapter 8. Static Testing of Geothermal Drilling Fluids (550°F)

Summary

All but one of the water muds statically aged at elevated temperature experienced an increase in yield point which was excessive in most cases. The water muds tested also had excessive filtrations, however two of the oil muds had excellent filtration characteristics.

Experimental Procedure

Separate samples of the ten water base muds submitted were aged in high pressure cells for 24 hours at conditions of (a) 450°F - 300 psi and (b) 500°F - 375 psi and (c) 500°F - 15,000 psi. The five oil muds were aged at 550°F - 500 psi as well as at the four conditions listed above.

After static aging, all samples were cooled to 125°F and various mud properties were determined. Data sheets 16-30 in Appendix B list all results. Figures 39-44 present results obtained for the yield point and filtration tests only.

Test Results - 9 ppg Water Mud

Viscosity -- Mud A, B, C and D experienced excessive thickening when heat aged. As shown in Figure 39, mud E had a yield point which dropped from 7 to about 2 lb/100 ft². Data Sheet 20 in Appendix B also shows that this mud had gel strengths less than 3 lb/100 ft² which makes it unacceptable.

Filtration Control Characteristics -- Static aging caused all five muds to have higher fluid losses. After aging at 450°F, two of the muds (B and C) had acceptable filtration characteristics, however, after aging at 500°F all muds had excessively high fluid loss (see Figure 40).

Test Results - 18 ppg Water Muds

After aging none of the five 18 ppg water base muds had acceptable mud properties.

Viscosity -- As shown in Figure 41, progressive degradation of the mud occurred as the temperature was increased. Also, three of the muds (G, I and J) had yield points in excess of 200 lb/100 ft² after 500°F aging at 15,000 psi. Such gellation would appear as a solid "plug" and make circulation in an actual well practically impossible.

Filtration Control Characteristics -- The data of Figure 42 shows that after high temperature aging all 18 ppg water muds had poor filtration characteristics. As expected, the 500°F aging was more damaging to the muds than was the 450°F aging.

Test Results - 18 ppg Oil Muds

Figures 43 and 44 show that the 18 ppg oil muds experienced less degradation than the 18 ppg water muds. One of the muds tested, mud L, appears to be marginally acceptable.

Viscosity -- Mud L (Figure 43) experienced an increase in yield point with aging which was marginally acceptable. The other muds had yield points in excess of 60 lb/100 sq ft which is unacceptably high.

Filtration Control Characteristics -- Two muds (L and M) had excellent filtration characteristics after aging. The other muds had filtrates which were unacceptable. Even though muds K, N, and O had high fluid losses, the filtrate was all oil which is a good factor.

YIELD POINT OF MUD BEFORE STATIC AGING

**O.S. - OFF SCALE AT 600 RPM ON A FANN VG METER
(ONE MULTIPLIER SPRING)**

Figure 39. Yield point of 9 ppg water muds static aged 24 hours at the indicated temperatures and pressures

Figure 40. HTHP Filtrate of 9 ppg water muds static aged 24 hours at the indicated temperatures and pressures

O.S. - OFF SCALE AT 600 RPM ON A FANN
VG METER (ONE MULTIPLIER SPRING)

YIELD POINT OF MUD BEFORE STATIC AGING

Figure 41. Yield point of 18 ppg water muds static aged 24 hours at indicated temperatures and pressures

Figure 42. HTHP Filtrate of 18 ppg water muds static aged 24 hours at the indicated temperatures and pressures

Figure 43. Yield point of 18 ppg oil muds static aged 24 hours at indicated temperatures and pressures

Figure 44. HTHP Filtrate of 18 ppg oil muds static aged 24 hours at the indicated temperatures and pressures

Conclusions

- 1) None of the ten water muds subjected to high temperature static aging had acceptable viscosity and filtration control.
- 2) None of the five oil muds tested had good viscosity and filtration control and only one (mud L) had marginally acceptable characteristics.
- 3) In general the 18 ppg oil muds had better viscosity and filtration control than did the 18 ppg water muds.

Chapter 9. Corrosivity Testing of Geothermal Drilling Fluids

Summary

Laboratory tests have shown that only three of the fifteen submitted muds (all oil muds) passed all of the corrosion tests. Seven of the ten water muds had corrosion rates which were lower than 50 mils per year and; therefore, passed the corrosion rate test, but only three of the water muds passed the extremely sensitive hydrogen embrittlement test. Five water muds had iron sulfide in the corrosion products and only one water mud exhibited localized pitting.

Experimental Results

Extensive laboratory tests were run under both dynamic and static conditions at elevated temperatures and pressures so that corrosion rates for the various muds could be determined.

The corrosion rates in mils per year (mpy) measured after 64 hours are shown in Figures 45, 46 and 47 for one dynamic test (350°F and 300 psi) and three static tests (450°F and 300 psi; 500°F and 375 psi; and 500°F and 15,000 psi). In the oil mud tests (Figure 47), a fourth static test was run at 550°F and 500 psi. A detailed listing of all results is given in Data Sheets 31 to 45 in Appendix C.

The condition of the corrosion coupons after testing is listed in Tables 6, 7 and 8.

The coupons were inspected for (a) the type of corrosion, (b) the tendency for the mud to produce hydrogen embrittlement and (c) the presence of iron sulfide on the surface of the coupon.

In each dynamic test, data was taken at 8, 16, 40 and 64 hours. As expected, corrosion rates after short periods of time were higher than after longer periods of time. Figure 48 shows such a response for mud A which is typical.

Corrosion Results - 9 ppg Water Muds

Two mud samples, namely A and E, had corrosion rates which were below the recommended maximum of 50 mils/year in both dynamic tests (350°F) and static tests (450°F and 500°F) as shown in Figure 45. At 500°F muds B and C had much higher corrosion rates at 15,000 psi than at 375 psi.

Inspection of corrosion coupons revealed that iron sulfide was present on those exposed to muds C and D at 500°F (see Table 6). Prestressed roller bearings cracked in at least one test when exposed to all of the muds except for mud B. Corrosion was of a generalized nature on all of the coupons. No localized corrosion was detected.

Corrosion Results - 18 ppg Water Mud

All of the muds tested in this series had acceptable corrosion rates (i.e., less than 50 mpy) as shown in Figure 46.

The coupons tested showed corrosion to be of a generalized type except for those in mud G which experienced pitting when tested under dynamic conditions at 350°F and 300 psi (see Table 7). Only muds H and J passed the hydrogen embrittlement test under all test conditions with mud I showing only a slight cracking tendency. Mud G and J produced no iron sulfide on coupon surfaces.

Figure 45. Corrosion rate of mild steel in 9 ppg water muds

Mud	Temp, °F	Press, psi	Type Of Test	Hydrogen Embrittlement Tendency	Presence of Iron Sulfide
A	350	300	D	P	N
	450	300	S	N	N
	500	375	S	N	N
	500	15,000	S	N	N
B	350	300	D	N	N
	450	300	S	N	N
	500	375	S	N	N
	500	15,000	S	N	N
C	350	300	D	P	N
	450	300	S	N	N
	500	375	S	N	P
	500	15,000	S	N	P
D	350	300	D	P	N
	450	300	S	N	N
	500	375	S	P	P
	500	15,000	S	P	P
E	350	300	D	P	N
	450	300	S	N	N
	500	375	S	P	N
	500	15,000	S	N	N

P - Positive
N - Negative

D - Dynamic Test
S - Static Test

Table 6. Condition of corrosion coupons after testing in 9 ppb water muds

Figure 46. Corrosion rate of mild steel in 18 ppg water muds

Mud	Temp, °F	Press, psi	Type Of Test	Hydrogen Embrittlement Tendency	Presence of Iron Sulfide
F	350	300	D	P	N
	450	300	S	N	N
	500	375	S	P	P
	500	15,000	S	P	P
G	*350	300	D	P	N
	450	300	S	N	N
	500	375	S	N	N
	500	15,000	S	N	N
H	350	300	D	N	N
	450	300	S	N	N
	500	375	S	N	P
	500	15,000	S	N	P
I	350	300	D	Slight	N
	450	300	S	N	N
	500	375	S	N	P
	500	15,000	S	N	P
J	350	300	D	N	N
	450	300	S	N	N
	500	375	S	N	N
	500	15,000	S	N	N

P - Positive

N - Negative

D - Dynamic Test

S - Static Test

* Coupon experienced pitting.

Table 7. Condition of corrosion coupons after testing in 18 ppb water muds

Corrosion Results - 18 ppg Oil Mud

Three oil muds tested, namely L, M and O, passed all corrosion tests. Figure 53 shows mud K to have excessive corrosion under dynamic conditions and mud N to be marginal.

The coupons inspected showed only mud N to produce iron sulfide on its surface and muds N and K to produce some hydrogen embrittlement (see Table 8).

Conclusions

- 1) Of the fifteen submitted muds only three (muds L, M and O) passed all of the corrosivity tests. These were all oil muds.
- 2) Seven of the ten water muds (muds A, E, F, G, H, I, J) had corrosion rates lower than 50 mils per year.
- 3) Only three of water muds (muds B, H, and J) passed the extremely sensitive hydrogen embrittlement test.
- 4) Five water muds (muds C, D, F, H and I) had iron sulfide in the corrosion products.
- 5) Mud G produced localized pitting on the test coupons.

Figure 47. Corrosion rate of mild steel in 18 ppg oil muds

Mud	Temp, °F	Press, psi	Type Of Test	Hydrogen Embrittlement	Presence Of Iron Sulfide
K	350	300	D	Slight	N
	450	300	S	N	N
	500	375	S	N	N
	500	15,000	S	N	N
L	350	300	D	N	N
	450	300	S	N	N
	500	375	S	N	N
	500	15,000	S	N	N
	550	500	S	N	N
M	350	300	D	N	N
	450	300	S	N	N
	500	375	S	N	N
	500	15,000	S	N	N
	550	500	S	N	N
N	350	300	D	N	P
	450	300	S	N	P
	500	375	S	P	P
	500	15,000	S	N	P
	550	500	S	N	N
O	350	300	D	N	N
	450	300	S	N	N
	500	375	S	N	N
	500	15,000	S	N	N
	550	500	S	N	N

P - Positive

N - Negative

D - Dynamic

S - Static Test

Table 8. Condition of corrosion coupons after testing in 18 ppg oil muds

Figure 48. Typical results, dynamic corrosion tests for mud A at 350°F - 300 psi

Chapter 10. Potential Improvements in Geothermal Drilling Fluids

Introductions

In the design of a drilling fluid for geothermal development, the same relevant factors must be considered as are pertinent to the program for any other drilling operation. These factors include; the depth, the temperature and the character of the rocks and the fluids contained in the rocks. Such properties of the rocks as strength, chemical composition, porosity and permeability, and the chemical composition and the phase behavior of the contained fluids, affect the drilling fluid and may be affected by the drilling fluid. The drilling equipment, casing program, methods and objectives in completion and production-these and numerous other factors enter the planning. Economic considerations cannot be ignored. Obviously, all of the significant inter-relationships cannot be dealt with in a survey of drilling fluids for geothermal drilling operations. Attention will be directed instead to the broad classes of drilling fluids; gaseous, water base, and oil base.

Gaseous Drilling Fluids

Dry Air -- The use of dry air as drilling fluid is restricted to stable formations that do not contain significant quantities of water. The cost of installation of sufficient compressor capacity to supply the enormous volume of air required for a large diameter hole excludes the use of dry air in most instances. The limiting factor in medium diameter holes (8-1/2 - 12-1/4 inches) is the hazard of a blowout because of the failure of the air to cool the hot rocks adequately. Dry air has found little application in geothermal drilling and no significant improvements in the process are anticipated.²⁸

Foam -- Foam, employed in drilling, is a dispersion of air in water containing a surfactant, the "foaming agent," that promotes the formation of a liquid film around the air bubble. Usually substances are added to increase the stability of the foam and to produce "gel foam" or "stiff foam" having an improved capacity to support cuttings. This improvement in foam performance was initiated at the Atomic Energy Commission's Nevada Test Site and modifications have been made in the composition of the additives to increase the hole-stabilizing qualities of the foam.²⁹

Foam is produced by injecting the foaming and stabilizing agents into the air going into the drill string, or is "pre-formed" at the surface in equipment developed by Standard Oil Company of California.³⁰

In a recent review, G. W. Anderson³¹ states, "Preformed stable foam has seen limited use in drilling for geothermal steam, however, it has demonstrated an excellent potential with certain improvements in equipment and refinements of the technique. The technique needed to realize the full potential of geothermal drilling with preformed stable foam is the application and control of back pressure on the annulus while circulating foam." A mathematical model of foam circulation has been devised that can be used in calculating the effect of operating conditions on pressures.³²

The limited use of foam in geothermal drilling has not clearly defined the needs for improvements. The thermal stability of foaming agents has received little attention. Most of the effective foaming agents contain sulfur as sulfonate or sulfate. When such surfactants are decomposed by heat, corrosive compounds are formed. Oxygen and water are normal constituents of the mixture, and the detergent action of the foaming agent tends to promote corrosion, even when sulfur is absent. Compatibility of the foaming agent (and of the stabilizing substances) with applicable corrosion inhibitors should be investigated before a composition is recommended for geothermal drilling.

Water Base Drilling Fluids

Many and varied changes take place when water muds are heated. In addition to thermal degradation of some of the constituents, reactions occur between some components and between components and the rocks and fluids exposed in the borehole. Both temperature and time of heating are important in studies of thermal stability. Exaggerated claims have been made for some materials on the basis of short-term tests at elevated temperatures.

In general, the approach to an improvement in the thermal stability of muds has involved: (1) addition of a substance that will reduce the breakdown of one or more of the constituents, or (2) modification of the composition through the use of more stable components. Representative of the first approach are several U.S. patents on the addition of alkali metal chromates to muds containing lignosulfonates and lignite (for example, see Reference 33). Such treatments frequently permit the continued use of a mud at a temperature somewhat higher than is practical without addition of chromate. As is discussed in Chapter 8, on "Replacement of Mud Components," the mud to be left in the hole when circulation is stopped can be treated extensively, and subsequently be discarded or reconditioned.

The second approach to improved thermal stability is illustrated by the substitution of leonardite (usually called lignite) for less stable materials in order to control filtration and flow properties. When used with a polyoxyethylene ether of phenol (DMS), leonardite provides filtration control after heating 352 hours at 400°F (204°C).^{34,35} The lignite-surfactant system has been used for years in drilling geothermal wells.^{36,37}

Various agents have been patented as stabilizing materials for muds at "high temperatures." In many instances, the "high temperature" was about 300°F (149°C), the exposure was relatively short, and filtration was not measured at the elevated temperature. Cowan³⁵ noted that polyacrylates did not control filtration at 400°F (204°C), although after the heated mud had been cooled to room temperature the volume of filtrate was low.

A few examples will illustrate the variety of products that have been patented. A sulfonated-lignite chromium complex maintained satisfactory properties (as measured at room temperature) after aging 16 hours at 400°F (204°C).³⁸ Rosin amine alkylene oxide condensation products improved stability of gyp and salty muds, as indicated by room temperature tests after aging at 400°F (204°C) for 72 hours.³⁹ Superior heat stability is claimed for a mud containing an "open chain poly-n-vinyl carboxylic acid amide as protective colloid".⁴⁰ Again, tests were made at room temperature after aging 10 hours at 482°F (250°C).

Somewhat more conclusive tests are reported for muds treated with sodium polyacrylate of molecular weight less than 2500.⁴¹ Comparative results are shown for mud samples tested in the Fann consistometer. The maximum time of test was 5-1/2 hours at 440°F (227°C) at pressures exceeding 11,000 psi. Static aging was at 450°F (232°C) for 16 hours before flow properties were measured at room temperature.

Another Milchem invention is a low molecular weight copolymer of styrene sulfonic acid and maleic anhydride.⁴²

Molecular weight of the styrene-maleic anhydride copolymer before sulfonation is stated as being between 1000 and 5000. Flow properties were measured at room temperature after static aging for 16 hours at 485°F (251°C). Filtrate (API) remained low. Tests were made also in the Fann consistometer on a mud containing 3 lb per bbl of the copolymer. Definite thickening was evident after two hours at 500°F (260°C), although little change in consistency was noted after 8 hours at 400°F (204°C).

Novel Material for Use in Water Base Muds

In the search for novel drilling fluid components which are to provide temperature stability for geothermal drilling, special attention must be given to the realm of clay minerals and potential clay mineral substitutes as well as thinners and potential substitute thinners.

Novel Clay Substitutes -- The use of the montmorillonite type minerals is a general practice in oilfield applications. Bentonite, a weathered volcanic ash made up of the clay minerals montmorillonite and beidellite, is widely used throughout the world because of its ability to absorb large amounts of water and swell accordingly.⁴³ Montmorillonite is defined as a group of clay minerals (including montmorillonite, nontronite, saponite, hectorite, sauconite and slevensite) whose formulas may be derived by substitution in the general formula $Al_2 Si_4)_{10} (OH)$ with deficiencies in charge in the tetrahedral and octahedral position balanced by the presence of cations, most commonly Ca and Na, subject to ion exchange. They are characterized by swelling in water due to introduction of interlayer water in the direction of the c-axes.

Bentonites used in water base drilling fluids are a product of weathering and in turn are stable in a basic pH (above 7). They are ideally suited for water base drilling fluids normally run at pH of 9-11. The swelling of the bentonite gives the drilling fluid the carrying and rheological properties needed in modern drilling fluids. These same properties that make

bentonite the ideal agent in drilling fluids at lower temperature in the earth limit its use at higher temperatures. It is unusual for montmorillonite to be found at depths greater than 10,000 feet. The delicate basic crystal structures become unstable at existing temperatures, pressures, and geologic chemical conditions and the montmorillonite structure goes to a more stable clay mineral form. This change is generally referred to as the first and/or second stage of diagenesis, depending on whether the clay structure has gone to a non-reversible clay mineral form.⁴⁴

Geothermal drilling takes place, at least in part, in a totally different geologic environment than that of drilling for petroleum products. The sedimentary environment of most oil and gas well drilling is the end product of the weathering process which forms montmorillonite-type clay minerals. Geothermal drilling is conducted in an environment of either metamorphic rock (sedimentary altered by heat and pressure) or igneous rock. There exist two separate and distinct environments of igneous rocks, those of the acid environment (the light colored granites, etc.), and those of the basic environment (the dark colored granites). These environments also exist in the metamorphic rocks. The end environment of the metamorphic rocks depends upon the makeup of the sedimentary rocks that have been altered (i.e., whether they were the weathered end product of acid rock material or basic rock material) and the type of igneous material, if any, that was mixed with the sedimentary rocks during the metamorphic process.

With these basic facts in mind the different suites of minerals that are stable in the metamorphic environment must be analyzed in order to determine if a suitable substitute for the bentonite used in oilfield drilling fluids can be located.

Minerals are responsive to their environment. They are stable, for the most part, under the conditions in which they were formed but become unstable in different environment. Clays formed on the earth's surface and later buried deeply beneath a pressing load of sediments will change to more

stable forms of muscovite or other silicates, under the new environment of increased pressure and temperature. The fields of stability of many minerals are known, thus broad generalizations can be made concerning weathering, hydrothermal alterations, metamorphism, temperature of formation of mineral deposits and temperature range of stability.

Since most geothermal wells are drilling into either metamorphic rock associated with nearby heat bearing igneous rock or into igneous rock itself (volcanic or associated volcanic rocks), it is a natural step to investigate the temperature stable metamorphic minerals of the asbestos family. Minerals such as asbestos, and very finely divided silica, for example, can supply the needed carrying capacity to remove cuttings from the hole. Especial stability is claimed for muds containing a mixture of chrysotile asbestos and fumed alumina, based on static aging for seven days at 300°F (149°C).⁴⁵ While this group of minerals has already undergone considerable investigation in drilling fluids, it bears closer scrutiny for possible application in geothermal drilling fluids. The two main varieties of asbestos, serpentine asbestos (hydrous magnesium silicates) and amphibole asbestos (silicates of calcium, magnesium, iron, sodium and aluminum) may both have specific applications in the drilling of geothermal wells located in chemically different reservoirs.

The Talc family (hydrous magnesium silicate) warrants a close investigation for possible clay substitutes in geothermal drilling fluids. In this family, we must also include pyrophyllite (hydrous aluminum silicate) as a potential clay substitute.

The Sillimanite group, which includes andalusite, kyanite, sillimanite (all $Al_2O_3 \cdot SiO_2$) and dumortierite (aluminum borosilicate), are commonly used in refractories and may have strong potential for use in drilling fluids in geothermal wells where temperatures exceed 600°F. These minerals are known to be stable up to 1100-1650°C before converting to mullite and, therefore, should remain quite stable in the fluid environment that would be necessary for extremely hot geothermal wells of the future.

The Attapulgite-Sepiolite group bears a close inspection for possible substitutes as clay in geothermal drilling fluids. Attapulgite is presently used in oilfield drilling fluids and has proven its value in special oilfield applications. Sepiolite, commonly called meerschaum, is a hydrous magnesium silicate which may be an excellent candidate for use in geothermal drilling because of its similar fibrous structure to attapulgite. Palygorskite, which also belongs to this group, has appropriate properties for careful testing for geothermal use. Some of these clays have been synthesized under conditions which should lead to stability at temperatures of at least 600°F (315°C).

In the general survey for a clay mineral substitute in geothermal drilling fluids the above mentioned groups could first be reviewed as to applicability by use of thermal gravimetric analysis (TGA). The minerals that show any radical physical change in the 300-600°F range can be discarded as potential replacements for clay minerals in geothermal drilling fluids. The minerals showing stability by TGA analysis can then be tested by standard API drilling fluid tests to determine if the mineral is acceptable for use as a bentonite replacement. The minerals showing any promise by the API test should then be both static and dynamically tested under heated conditions with a further narrowing of the possible clay mineral replacement for geothermal application.

It is well known in oilfield drilling fluid application that fine particles add greatly to the viscosity of drilling fluids, although some viscosity is needed. The accumulation of fine particles requires the jetting or discarding of part of the active drilling fluid system because of extreme viscosity in many cases. The part of the system jetted is then replaced with fresh drilling fluid containing little or no fines. By proper mechanical conditioning with existing oilfield equipment, and other equipment such as high speed centrifuges, the viscosity of a geothermal drilling fluid could be controlled by the particle size of the mineral that is used to replace the clays in a geothermal drilling fluid. A study of initial viscosity versus particle size of the mineral used should be useful in evaluating candidates for geothermal drilling.

Novel Thinners -- In general oilfield practice, an oxidized lignite or brown coal (leonardite) is commonly used as a thinner to control surface electrical charges on drilled rock material. In other cases, extracted organic material from wood pulp is dried and used as a chemical for controlling surface or edge charges. Some of this material may well be applicable in geothermal drilling. The mechanism that is involved in extracting the useful organic from the lignite or brown coal is the alkalinity of the mud and the temperature of the borehole.

A standard chemical extraction procedure for organics from coal, wood, and rock is to pass a heated high-pH liquid over the material until no visible color is seen in the fluid passing through. This process may be enhanced in a vacuum or in an oxygen-free atmosphere. Possibly a more effective leonardite product could be made by altering the method used to produce a water-dispersible material, e.g., solubilizing by a silicate for controlled alkalinity.

In geothermal drilling, where much higher temperatures are reached, the total coal series (1. brown coal or lignite, 2. subbituminous, 3. bituminous, 4. semibituminous, 5. semi-anthracite, and 6. anthracite) must be evaluated as possible sources of organic thinners and inhibitors for geothermal wells. As the coals grade to the harder material, they naturally give up their organic material at higher temperatures; this natural phenomenon may provide a thermally stable material for use in geothermal drilling fluids.

Oil Base Drilling Fluids

The reactions of the normal components of water mud with one another and with the formations drilled limit the usefulness of water base muds at temperatures above 600°F (316°C). Consequently, nonaqueous liquids appear to offer possibilities for high-temperature mud compositions.⁴⁶

"The forced selection of a nonaqueous continuous phase for the mud narrows the search for a stable liquid to high-temperature

lubricants, hydraulic fluids, and heat-transfer liquids. Such liquids fall into the general classes of aromatic or polyphenyl ethers, aromatic or phosphate esters, and aromatic silicates, silanes and silicones, and possibly, certain naphthenic and paraffinic oil and halogenated hydrocarbon esters.

"The required suspending and sealing qualities may be supplied by carbon black and gellants for high-temperature greases.

"As has been pointed out earlier, current facilities for testing such compositions for use as drilling fluids are inadequate and these speculations are unsupported by any experimental performance tests."⁴⁶

Among the high-temperature liquids that can be thickened by organophilic clays are:

Product	Source	Identification
Emolein 2910	Emery Ind.	Dipropylene Glycol Dipelargonate
Emolein 2957	Emery Ind.	Di-1sooctyl Azelate
Emolein 2958	Emery Ind.	Di-2-ethyl Hexyl Azelate
Plexol 201	Rohm & Haas	Di-2-ethyl Hexyl Sebacate
Hatcol 2970	Hatco Chem.	Penta Erythritol Ester
Bryton FF	Conoco	Synthetic Hydrocarbon
DN 600-1	Conoco	Synthetic Hydrocarbon

A superior filtration-control agent for oil mud at high temperatures is reported to be a vinyl toluene-acrylate copolymer resin and blown asphalt.⁴⁷ No aging tests are reported. Filtration tests showed 1.9 cc after 2 hours filtering at 530°F (277°C), 300 psi, for an oil mud containing 10 lb per bbl of the agent, and 8.6 cc at 450°F (232°C), 5000 psi, with 7 lb per bbl.

Stable suspending agents can be produced by treating normally hydrophilic substances with agents that convert the surface to a hydrophobic condition. Possible approaches to this procedure may be indicated in some U.S. patents.⁴⁸⁻⁵⁰ The patents listed cite numerous other patents dealing with related processes.*

* General references on clay materials are References 51-58.

Chapter 11. Engineering Alternatives

Introduction

The task of using muds in the geothermal environment can be made simpler and more efficient by the use of various engineering techniques and tools. In fact, it probably is impossible to efficiently drill geothermal wells without some of the techniques, tools and concepts that are herein described as "engineering alternatives." The use of such alternatives may substantially increase the maximum borehole temperature applicability of some components of the drilling fluid, and may make economically practical the drilling of high temperature geothermal wells using current technology.

Cooling the bit has long been recognized as a primary function of the drilling fluid. The circulating drilling fluid carries heat, generated by the bit in piercing the rock, up to the surface to be dissipated. As the drilling fluid moves toward the surface, the drill string and the hole wall constitute a heat exchanger system. This heat exchange system and heat generated within the system (such as pipe friction loss) results in changes in temperature of the drilling fluid and possible alteration of its properties.^{59,60} A significant side effect can be the changes occurring in the temperature of the exposed formations.^{61,62}

Mud Temperature Limits

Chapter 1 points out the temperature limits of muds (Figure 49). The upper theoretical limits of any water based mud system (one that would be environmentally acceptable) is about 375°C (700°F) which is the critical temperature of water (Figure 50). Values in Figure 49 should not be taken as an absolute but rather as the average of experience on the part of people involved in mud and drilling as to an upper economic/problem limit. Obviously, many different factors such as well depth, lithology, daily costs, etc., are involved.

Figure 49. Temperature limits of conventional mud systems⁶³⁻⁶⁶

There are three basic ways to overcome the temperature limitations of muds:

- 1) Develop muds which will function at higher temperatures
- 2) Keep the mud cool
- 3) Replace mud components as they degrade.

The first topic, improved high temperature muds, is the subject of a later chapter and will not be discussed here. The other two topics, keeping the mud cool and component replacement, will be introduced by discussing sources of heat influx and outlining ways of dealing with this heat influx.

Figure 50. Critical temperature of water

Source of Heat Influx

High temperatures in geothermal wells cause problems with mud systems because many of the organic and materials degrade at higher temperatures. Water base muds are currently limited to temperatures of 350-450°F due to these degradation problems. Oil muds can be used at temperatures up to 550°F, but cannot currently be used in some areas due to environmental problems.

There are many different energy sources which contribute to heating the mud. Some of the more important of these are:

- 1) Heat from hot formations
- 2) Friction losses in mud circulation system
- 3) Mechanical energy imparted to the rock by the bit
- 4) Formation heat contained in rock cuttings introduced into the mud
- 5) Friction heat generated by the drillstring friction against the casing and rock
- 6) Chemical reactions between mud components and between the muds and the formation being drilled.

The following sections deal with methods of reducing the mud temperatures in these hot wells. Systems to be discussed include:

- 1) Increase Mud Specific Heat
- 2) Solids Control
- 3) Cool or Refrigerate
- 4) Increase Mud Circulation Rate
- 5) Uninterrupted Circulation
- 6) Alter Circulation Pattern
- 7) Insulate Borehole and Drill String
- 8) Employ Special Drilling Practices

The discussion also examines the economic practicality or maintenance of mud properties, adequate to meet drilling requirements, by systematic replacement of degraded mud components.

Increase Mud Specific Heat

The mud temperature decreases as the specific heat of the mud increases because for a given input of energy the temperature rise is smaller. The total amount of heat being removed from the wellbore is larger, however, due to the larger differential temperatures involved; consequently, increased cooling is needed at the surface to remove this heat as the specific heat of the mud increases.

Specific Heat of Mud -- The specific heats of different mud components are given in Table 9:

<u>Material</u>	<u>Specific Heat (Cal/g/°C)</u>
Water	1.00
Oil	0.60
<u>Mud Additives</u>	
Clay (Bentonite)	0.20
Barite	0.10
<u>Rock Formations</u>	
Sandstone	0.19
Limestone	0.20
Shale	0.20
Granite	0.19
Basalt	0.20

Table 9. Specific heat of mud components
(HANDBOOK OF CHEMISTRY & PHYSICS)

The specific heat of the mud, C_p (mud), equals:

$$C_p(\text{mud}) = f_f C_p(\text{fluid}) + f_s C_p(\text{solids}) \quad (1)$$

f_f = Fluid Fraction (by weight)

f_s = Solids Fraction (by weight)

C_p (fluid) = Specific Heat Fluid Phase of Mud

C_p (solids) = Specific Heat of Solids

Typical values for unweighted water-base and oil-base muds (i.e., no barite) are:

$$C_p(\text{water base mud}) = 1.0 f_w + 0.2 f_s \quad (2)$$

$$C_p(\text{oil base mud}) = 0.6 f_o + 0.2 f_s \quad (3)$$

where

f_w = Water Fraction (by weight)

f_o = Fluid Fraction (by weight)

Figure 51 shows how the specific heat decreases with increased solids content (Equations 2 & 3).

The specific heat of weighted muds containing barite would be slightly lower because the specific heat of barite is 0.10 compared to 0.20 for other solids in the mud. The percent of solids in the mud increases as the mud weight increases due to the addition of clays and barite as illustrated in Figure 5. The dashed lines in Figure 51 correspond to the maximum solids curve in Figure 52 without accounting for the difference in specific heat of barite and other solids in the mud. This illustrates that the specific heat of the mud decreases as the mud weight increases, a detrimental effect since this allows the mud temperature to increase more for a given heat influx. This is unfortunate since more chemicals are needed in the heavier muds and these chemicals degrade rapidly at the higher temperatures.

Figure 51. Specific heat of muds

Figures 51 and 52 show that the mud specific heat can be increased by using a liquid phase with high specific heat and by keeping the percent solids in the mud as low as possible.

Approximate Range of Solids
Percent by Volume (Field Muds)

Figure 52. Percent solids in drilling muds (Magcobar Manual)

Solids Control

The removal of cuttings and cavings from drilling mud is an essential part of any process for conditioning the drilling fluid. The buildup of solid particles in a drilling mud causes or contributes to many problems. These include:

- 1) High temperature mud solidification
- 2) Mud density increase
- 3) Mud viscosity increase
- 4) Drilling rate decrease
- 5) Increased tendency for the pipe to stick
- 6) Increased wear on drilling equipment
- 7) Increased mud instability with regard to salts and temperatures

While drilling, a large volume of cuttings is generated. For example, during the course of drilling 5000 feet of a conventional 8-3/4" diameter hole, there will be over 2000 cubic feet cuttings. If a very modest 50% caving is postulated, there will be a total of about 3000 feet³ of rock to be removed. Because of the necessity of removing these larger volumes of cuttings, various types of mud cleaning or solids-removal equipment have been developed (Figure 53). This equipment is discussed in the following sections.

DESANDING AND DESILTING CYCLONES

DECANTING CENTRIFUGE AND 5cm CYCLONE

- Removes Low-Gravity Solids and Barite smaller than 8-15 Microns.
- Returns larger solids to Active Mud System.
- Operates on Small Fraction of total Mud System.

- Removes drilled solids larger than ± 70 Microns before they degrade into ultra fine solids which cause viscosity build-up. Barite may be removed with drilled solids.

- Operates on entire circulating volume.

FINE SCREEN SHALE SHAKER

- Removes drilled solids larger than 175 Microns.
- Returns smaller solids to Active Mud System.
- Operates on entire circulating volume.

Modified after
SWECD 1975

Figure 53. Mechanical solids control of drilling mud

Shale Shaker -- The shale shaker (or vibrating screen) is the primary unit of solids control equipment. The shale shaker receives the mud returns at the flowline. The shaker is equipped with screens with mesh openings ranging from 160 - 300 μ . Fine screens (60 - 175 μ) require the use of a coarser scalping screen as shown in Figure 54.

Figure 54. The shale shaker (for the removal of coarse drill cuttings and cavings)

In geothermal drilling, the shaker should be fitted with 175 μ (80 mesh) (or finer) screens to remove as much of the mud solids as possible. Screen use will be limited in some instances by the presence of lost circulation materials since these materials would be passed over the screen and lost.

Hydrocyclone -- The hydrocyclone is another basic mud-cleaning tool (Figure 55). The hydrocyclones used with drilling mud vary in size from 12" in diameter to 2" in diameter. In hydrocyclone terminology the "cut" is the center of the removal distribution curve and is often considered the effective lower range of removal. The cut of hydrocyclones used with drilling muds is from 120 - 15 μ . Like any other device, there are efficiency penalties; thus the smaller the cyclone and the finer the cut, the smaller the volume treated and the higher the pressure required.

Figure 55. The hydrocyclone (desilter for the removal of silt-sized particles in the drilling mud)

Application of hydrocyclones in geothermal drilling depends upon the operating conditions. In igneous drilling, the small cyclones should be used to remove the abrasive materials from the mud. Other problems may require other sizes of cyclones.

Centrifuge -- The decanting centrifuge (Figure 56) and the 2" cyclone are used to recover barite from high density drilling fluids, such as would be used in geopressured provinces. In such cases, the remainder of the mud is discarded and the barite used to mix new mud.

Figure 56. The decanting centrifuge (used for the recovery of barite from high density drilling fluids)

The use of solids control equipment in geothermal drilling would be no different than its use in hydrocarbon drilling. It

is an essential part of an economical and efficient operation. Most of the solids control equipment would be sensitive in some degree to very hot muds and should be placed in the surface mud system after the heat exchanger.

Cool or Refrigerate the Mud

Cooling the mud on the surface may be necessary as a matter of safety and protection of the surface equipment. Since the heat conductivity of mud is so low, the mud in very hot holes would eventually start to carry high enough recycle temperature to build an increasing temperature cycle. The following sections discuss aspects of cooling the mud on the surface.

Surface Heat Exchangers -- Surface heat exchangers will be needed for the drilling mud as soon as the surface mud temperatures exceed approximately 75°C. Exchangers have been used in New Zealand,⁶⁷ El Salvador,⁶⁸ and one was built by the U.S. Interior Department for use in the Imperial Valley. There has been other work of this nature done by various organizations.

The specific heat of mud varies from less than 0.5 for very heavy muds to 0.9+ for the light muds that would normally be used for shallow, hot geothermal wells.⁶⁹ A simple approximation of the heat to be withdrawn would be to assume a temperature reduction of 30°F and a circulating rate of 200 gpm with water. To satisfy these conditions requires the removal of 50,000 BTU/min or 3×10^6 BTU/hr. Significant energy usage is necessary to dissipate this quantity of heat, particularly considering the low thermal conductivity and viscous nature of drilling mud.

The heat exchangers that have been used for mud cooling have generally been towers with a counter air flow (Figure 57). The general size has been about 3m x 3m x 10m. A 10 HP motor and pump has sometimes been provided to move the mud to the top of the tower and a 5 or 10 HP fan has been used to provide the air counterflow. One operator uses either (1) forced draft, 8 x 6 ft, solid sides, 10 ft free fall, or (2) gravity flow, 8 x 8 ft, louvres, 22 ft fall. They provide capacity for cooling of 1-1/2 times the volume being circulated in the hole. Either

Figure 57. A light truck-mounted rig of the kind first used at Warakei at work. The cooling tower shows at left.

type will afford a temperature reduction of about 40°F, with normal additions of water at the shaker.

Reports uniformly agree that the cooling thus provided was adequate for the purpose, but it has been impossible to obtain precise records of heat removal.

Some of the problems experienced with these heat exchangers have been:

- 1) Large size and weight for transportation and erection;
- 2) Mud spatter on the location due to the air counter flow;
- 3) Mud buildup on the heat exchanger vanes.

Another method of tower type heat exchanger might be to use a fine screened shale shaker on an open frame. The screen may break the mud up enough to obtain a reasonable heat exchange as well as remove the drill cuttings. No fan would be used with this system which would depend on natural convection (Figure 58). This system would be somewhat easier to move, would not require much extra construction and would avoid the mud buildup and some of the mud spatter.

A relatively simple heat exchanger would be a fountain (Figure 59). This type of heat exchanger might be very satisfactory for mud because of its simplicity.

The simplest heat exchanger of all is a broad shallow pit with a long circulating path. This sort of system has generally proven unsatisfactory with drilling mud because of its tendency to set up in a gel and force the fluid down narrow channels.

A binary mud to water heat exchanger system was developed by the Gulf Oil Company while working on impact drilling research that has a number of advantages; it eliminates mud spatter solids buildup on exchanger vanes; it eliminates the high energy usage of refrigeration; and it allows the system to be kept pressurized to avoid flashing. Additionally this heat exchanger can be fabricated from readily available components.

The heat exchanger system consisted of a series of pipes laid in a water bath. The mud was pumped through the pipe and exchanged heat with the water bath which was cooled by an evaporation tower (Figure 60).

Figure 58. Proposed shale shaker heat exchanger tower.
Mud pumped in the shale shaker would be broken up over screen and fall as sheets to provide heat exchange and solids control.

Figure 59. Fountain type heat exchanger. Fabricated standard mud tank. Three fountains available to be turned into line as mud temperature increased. They could be thermostatically controlled.

Figure 60. Gulf Oil designed binary heat exchanger

Mud Cooling by Refrigeration -- Cooling the mud by refrigeration is a special aspect of cooling the mud on the surface to limit degradation of the mud as it is circulated in the borehole. A refrigerated cooling system is more complicated and more expensive to install and operate than other heat exchange methods discussed in "Engineering Alternative" and therefore should be considered only after careful economic comparisons.

The refrigerated system is conceptually very similar to the binary heat exchange system discussed in the prior section. A block diagram of a typical system is shown in Figure 61.

Figure 61. Schematic of refrigerated circulation system

Hot mud from the annulus is pre-cooled by stabilization in the mud pits or by some means as described in the earlier sections. This should reduce the mud temperature 25-50°F or more. The mud is then heat exchanged with the refrigerant fluid, after which the mud goes to the mud pumps for recirculation into the well. If required, the mud can go through a final- or after-cooling stage just before entering the rotary hose, stand pipe and drill pipe. However, because the mud is now at high pressure, heat exchangers are more costly, and after-coolers

are not likely to be economically attractive.

Water, brine, ammonia, freon or some other heat exchange fluid is used to exchange heat with the mud in circulating system. The heat exchange fluid is circulated through a refrigeration (mechanical cooling) system to remove heat picked up from the mud.

Figure 62 shows a typical closed-circuit, vapor compression refrigeration. Figure 63 shows comparative temperature relations for some of the different refrigerant fluids which can be used.

Figure 62. Simple closed-circuit vapor-compression system⁷¹

Figure 63. Comparative temperature relations for fluids of a simple system⁷¹

The amount of mechanical cooling required is, obviously, a function of the amount of heat to be removed from the mud. This will be a function of heat capacity of the mud, mud outlet temperature, circulating rate, objective temperature, etc.

$$\text{Cooling Requirement} = [T(\text{out}) - T(\text{in})] \times \text{heat capacity} \times \text{circulation rate} + (\text{heat added in surface system})$$

For example, assume

$$C_p (10 \text{ lb/gal}) = .91 \text{ BTU/lb } ^\circ\text{F}$$

$$\text{Circulation Rate} = 400 \text{ gpm}$$

$$\text{Outlet Temperature} = 200^\circ\text{F}$$

$$\text{Outlet Temperature of Precooler} = 160^\circ\text{F}$$

$$\text{Inlet Temperature} = 75^\circ\text{F}$$

$$\text{Pump Heating} - \text{negligible}$$

$$\begin{aligned} \text{Cooling Requirements} &= (160-75)(.91)(10)(400)(60) \frac{\text{BTU}}{\text{HR}} \\ &= 1.86 \times 10^7 \frac{\text{BTU}}{\text{HR}} \\ &= 1.55 \times 10^3 \text{ Tons} \end{aligned}$$

To put this in perspective, this would be the cooling required for 400-500 typical homes in a semi-tropical climate.

In summary, mechanical refrigeration may be required to maintain sufficiently low mud inlet temperatures in very hot holes. However, refrigerant cooling will require larger systems that will be expensive to install and operate. Refrigerant systems would probably be implemented only in conjunction with other alternatives discussed in this chapter.

Increase Circulation Rate

Figure 64 shows that as the circulation time increases, the bottomhole temperature decreases and the surface outlet temperature increases. A near steady state condition is reached after about 10 hours for the conditions shown.

A study of Holmes and Swift⁶¹ makes it possible to construct a steady state description of the effect of circulating rate down the drill pipe and up the annulus (Figure 65) based on typical mud circulating conditions for a Gulf Coast well. This study showed that it is desirable to circulate with as short a trip time as possible. The effect of fast trips is discussed in a later section on special drilling practices.

Figure 64. Effect of time on temperature for a simulated well⁶²

Well depth, ft	15,000
Drill stem OD, in.	6 $\frac{5}{8}$
Drill-bit size, in.	8 $\frac{3}{8}$
Circulation rate, bbl/hour	300
Inlet mud temperature, °F	75
Mud viscosity, lb/(ft-hour)	110
Mud thermal conductivity, Btu/(ft-°F-hour)	1.0
Mud specific heat, Btu/(lb-°F)	0.4
Mud density, lb/gal	10.0
Formation thermal conductivity, Btu/(ft-°F-hour)	1.3
Formation specific heat, Btu/(lb-°F)	0.2
Formation density, lb/cu ft	165
Surface earth temperature, °F	59.5
Geothermal gradient, °F/ft	0.0127

Figure 65. Well and mud circulating properties for a Gulf Coast well. Temperature profiles for the fluid in the annulus and drill pipe during circulation⁶¹

The Holmes and Swift paper demonstrated that increasing the circulating rate has a strong effect on reduction of temperatures (Figure 66). Doubling the circulating rate from 200-400 bbl/hr reduced the maximum mud temperature from approximately 200°F to approximately 150°F or about 36%, thus indicating that a greater mud velocity could resolve some of the high temperature mud problems.

Figure 66. Effect of varying mud rate on the temperature of the annulus during circulation⁶¹

Such high velocities in the annulus, however, may cause erosion. Hole erosion is a serious problem that leads to difficulties in hole cleaning (Figure 67). If the hole is not cleared of cuttings and cavings before a trip, it may be difficult to pull the drill pipe and it may be necessary to ream back to bottom, all of which increases trip time. Furthermore, enlarged hole can cause poor logs so that the information from electric and acoustic logs, as well as cutting analysis, is marginal.

The biggest problem with hole erosion is generally the difficulty in obtaining a good cement bond between casing and formation. Perforating and squeezing casing is a very expensive and time consuming operation.

Erosion by drilling mud occurs when the mud is in turbulence. This is generally defined as a Reynolds number above 2000.⁶⁸ The shear rate/shear stress numbers necessary to arrive at the Reynolds number are easily measured and the calculation of the onset of turbulence is then a reasonably simple task (Figure 68).⁶²

In general, annular velocities above 120 ft/min are approaching turbulence in a mud.⁷²

Another constraint to increasing circulating rate is the friction pressure in the annulus. The friction pressure caused by the mud in the annulus has the effect of increasing the

Figure 67. Hole erosion problems

Figure 68. Laminar/turbulent flow regimes in drilling mud⁷²

pressure exerted by the mud column. The onset of turbulence vastly increases this pressure. In areas where lost returns are common, high annular velocities may not be suitable (Figure 69).

**INCREASING ANNULAR
VELOCITY, ESPECIALLY
INTO THE ZONE OF
TURBULENCE CAUSES
INCREASED FRICTION.**

**THE FRICTION ACTS AS
A BACK PRESSURE AND
MAY CAUSE LOST RETURNS.**

Figure 69. Lost returns due to high annular velocity of mud

Uninterrupted Circulation

The study graphed in Figure 65 makes it apparent that a steady state or constant circulating system, would reduce borehole temperature while drilling to a level such that present drilling mud technology could be employed. The present practice is to stop circulating when pulling the bit to the surface to be changed and the drilling systems are built around this concept.

The most obvious method of minimizing interruptions of circulation involves a bit that can be replaced or repaired without removing the drillpipe from the hole. There has been work done in the past with bits of this nature but the bits were not as effective as conventional types (Figures 70a & 70b).

Figure 70. (a) Carter three-cone retractable bit⁷³
 (b) Soviet two-cone and three-cone retractable bits⁷³

Sandia Laboratories is doing considerable work in this area and the ERDA-sponsored Sandia reports should be referenced for further details on extended life in replacable and retractable bit elements.

A variation of the downhole changeable bit is drilling with casing instead of drillpipe.⁷⁴ The casing allows a reasonable internal diameter for bit changes but poses some other problems. The tool joints or casing connections are not as strong as those of drillpipe and have a considerable potential for failure. This problem, however, could be resolved. The small annular areas between the hole and the casing poses problems from pipe-sticking and from friction pressures which lead to lost circulation.

Another potential for constant circulation in the "parasite tubing string." This system has been used with aerated mud to provide constant circulation. The arrangement consists of two small tubing strings run on the outside of the casing (Figure 71).⁷⁵ The tubing allows constant circulation, independent of the drill pipe. It is limited by the difficulty of running the tubing and the fact that the tubing does not go to the bottom of the hole but only to the bottom of the casing. These considerations may not be major limiting factors in geothermal drilling and the use of parasite tubing strings may be a very practical method of circulating mud in the last casing string.

It is probable that a string of casing will be set just above the extreme temperatures because of geological and hole stability conditions. This casing then would be ideal for the parasite string of tubing.

Another approach to implementing the parasite tubing concept is to utilize a continuous, reelable tubing string which would be run to bottom just before tripping the drill pipe out of the hole. Thus circulation could be maintained during the trip. The tubing string would be removed after the trip is complete and the drill pipe back on bottom.

Figure 71. Parasite tubing string

A method of reducing the time it takes to make a trip could be a viable alternate to constant circulation. There have been some methods developed to significantly decrease the time taken to "trip." Two of the better systems involve the use of "spooled" drill pipe and hence require downhole motors. The downhole motors generally have temperature

sensitive lubricated parts, clearances, or elastomers so that they involve some constraints that would require careful evaluation.

Flexible pipe reeled on a large spool is used as drill tubing. It is also used when working over producing wells.⁷⁶ It is much faster to run than standard drill pipe or tubing and offers a considerable time advantage.

Another version of the pipe reel is the French-developed "Flexidrill." It utilizes a steel and elastomer hose in place of drillpipe.⁷⁷ The trip speed is very fast with this system, but elastomers in the hose may be temperature limited.

Alter Circulation Pattern

It would appear then that if the circulating patterns of the mud system could be changed, it would be possible to extend the usability of water base drilling fluids to the geothermal formation temperature range of 400-600°F. Beyond this point, several factors make drilling with the present state-of-the-art questionable.

Reverse Circulation -- The use of reverse circulation (down the annulus and up the drill pipe) offers potential solutions to some of the temperature problems (Figure 72).

Reverse circulation would provide cool mud at the drilling head and alleviate the now critical problem of the degradation of the elastomer sections when using an annular packoff (drilling head) for safety and pressure control situations.

There are, however, some problems arising when circulating in this manner. The drill bit would need to be redesigned because it does not drill efficiently in this mode. Friction pressures due to forcing the mud across the bit and up the drill pipe contribute to lost circulation. Finally, the hot mud comes to the rig floor through the drill pipe and could be a definite safety hazard.

Some other versions of reverse circulation might resolve some of these problems. The A.E.C. holes for nuclear emplacement

Figure 72. Normal vs. reverse circulation

used a dual string of drill pipe (Figure 73) and an air lift system. This type of drilling system offers some advantages, especially if geothermal drilling went to larger than conventional holes to increase productivity.

A continuous coring system called "Con-Cor" was developed using special drill pipe (Figure 74).⁷⁸ This system has potential in several fields. In addition to helping resolve the temperature problem, it is possible to get continuous cores. Also, in very hard drilling such as in granite and other igneous rocks, it is often faster to core than to drill, because coring reduces the amount of rock to be cut.

"A" ANNULAR AREA - NOT CIRCULATED

"B" ANNULAR AREA - CIRCULATION UP OR DOWN

"C" ANNULAR AREA - CIRCULATION UP OR DOWN

Figure 73. A.E.C. type big hole circulation

Figure 74. "Con-Cor" system⁷⁸

Insulated Drillpipe, Casing and Borehole Walls -- When drilling a geothermal well, cool mud is pumped down the inside of the drillpipe while hotter mud heated by the hot borehole walls rises up the annulus as shown in Figure 75.

Figure 75. Geothermal well circulating system⁶²

When circulation is initiated after a long trip (10-15 hrs), the mud temperature inside and outside of the drillpipe is close to the geothermal gradient. As circulation progresses, the mud temperature at the hole bottom decreases as cooler mud is pumped down the drillpipe while the temperature of the mud exiting the well at the surface increases as shown in Figure 76.

This figure also shows that if circulation is stopped, the temperature at the bottom of the hole rises and the temperature at the top of the hole decreases until the borehole is in static equilibrium with the formations along its length.

Figure 76. Effect of circulating time on annulus mud temperature⁶²

As circulation progresses, the cooler mud being pumped down the drillpipe results in a temperature differential between the mud inside and outside of the drillpipe as shown in Figure 77. This produces a heat exchange effect where heat flows from the mud in the annulus, through the drillpipe and into the mud going down the drillpipe. There is also a heat exchanger effect between the bottom and top of the hole. The formations at the hole bottom (i.e., below 12,300 feet in Figure 77) put heat into the mud while the formations at the top of the hole remove heat from the mud.

It is interesting to note in Figure 77 that the highest annular mud temperature occurs above the hole bottom, even though the highest formation temperature is at the hole bottom (400°F). This happens because cool mud exists the drillpipe and is heated as it rises in the annulus.

Because of the heat exchanger systems described above, three possible ways to reduce the maximum mud temperature are:

- 1) Use insulated drillpipe
- 2) Use insulated casing
- 3) Insulate the borehole walls

Figure 77. Mud temperature inside and outside of the drill-pipe after two hours circulation^{6,2}

Insulating the drillpipe will result in cooler mud reaching the hole bottom which is the hottest section of the hole. Since the highest mud temperature is reached near the hole bottom this will result in lower maximum mud temperatures in most cases.

Insulating the casing in the lower section of the hole will reduce heat transfer from the formation to the mud. This will reduce the maximum mud temperatures reached in the well. In the upper sections of the hole, the annulus mud is hotter than the borehole walls (e.g., above 12,300 feet in Figure 77), and heat flows from the mud to the formation. Insulating the wellbore in the upper section of the hole would therefore increase the mud temperature. Consequently, only the lower sections of the casing string should be insulated. Figure 78 shows a string of insulated casing used to drill the permafrost in the Arctic. Similar insulated casing could be used in geothermal wells.

Insulated casing will do little good in geothermal wells where long sections of open hole are drilled below the casing because the maximum mud temperature occurs in these lower sections of the hole. In this case, systems for insulating the borehole walls (i.e., the formations being drilled) could significantly lower the maximum mud temperature. Conceptually, additives could be added to the mud to produce insulated

Figure 78. Insulated casing used in drilling permafrost⁷⁹

granite or basalt or to produce insulated filter cakes on permeable formations. These linings and filter cakes could act as insulating barriers and could reduce the borehole wall heat transfer coefficient which controls heat flow from the formation to the wellbore.

Additional engineering studies are needed to more accurately evaluate the potential of using insulation to reduce the mud temperature.

Employ Special Drilling Practices

Balanced Pressure Drilling -- The concept of "balanced pressure drilling" may be a basic geothermal tool. It involves balancing the pressure exerted by the "mud" column with the pressure exerted by the formation fluid (hot water or steam).

In air drilling, the air column exerts much less pressure than does the formation fluids, so if there is permeability, there is an uncontrolled flow of steam. Water flow would make air drilling impractical or impossible.

In normal mud drilling, the mud column pressure prohibits the flow of formation fluids, but may cause lost returns into fractured zones.

In balanced pressure drilling the mud column is balanced against the formation pressure as closely as possible to prevent lost returns or uncontrolled flow. In the case of geothermal mud, this would also avoid the need for filtration control agents which, with the exception of bentonite, are organic substances that are altered by high temperatures.

True balance is difficult to achieve because of friction in the annulus - the mud exerts more pressure when circulating than when static. It can, however, be closely approached.

When the formation pressure has a gradient greater than water (0.43 psi/ft) (0.1 Kg/cm^2) it is quite simple to increase the density of a water-based drilling fluid with either salt or a weighting material.

When the formation pressure gradient is less than that of water, foam or aerated mud must be used. Aerated mud is less expensive but foam has much lower pressure surges and is easier to control (Figure 79). Bottom hole pressure is controlled according to:⁸⁰

$$hD - P = \frac{n}{100 - n} \ln (P+p)$$

where:

h = depth

D = pressure gradient (atm)

P = pressure at h due to fluid only (atm)

p = back pressure at well head (atm)

$\frac{n}{100}$ = fraction by volume of gas at the well head with back pressure p

- A. MUD PRESSURE GREATER THAN FORMATION PRESSURE - POSSIBLE LOST RETURNS AND HEAVY FILTRATION.**
- B. UNCONTROLLED FLUID ENTRY - A POSSIBLE BLOWOUT.**
- C. BALANCED PRESSURE DRILLING - DRILLING FLUID MAY BE MUD, AERATED MUD OR FOAM.**

Figure 79. Balanced pressure drilling

Pressure reduction is accomplished in the upper 700m of hole because of the gas expansion or unloading function and parasite strings of tubing can be used to good effect.

Hole Size Control -- The use of a small annular area might be considered as a method of reducing heat transfer to the mud by increasing annular velocity or as a method of reducing the amount of mud in contact with the formation. This approach might be attractive with the use of insulated drill pipe or an insulating foam mud.⁸¹ The limitations on annular velocity are quite real and the reduction of annular area would have to be part of a larger heat balance design.

One of the more significant methods of reducing relative heat transfer is the use of large boreholes. These may be required in geothermal wells to reduce heat transfer during production. The drilling of large holes may be quite expensive but the economics of the heat transfer and the reservoir characteristics, as well as the ability to use larger equipment in the hole, may override the increased hole costs. The increase in area as the square of the radius is very attractive from the heat conservation view point.

A number of the above techniques might be usable if large diameter holes were programmed. The drilling problems with large holes may be easier to resolve than the heat transfer and production problems with conventional size holes. Large holes resolve many geothermal problems concerning heat transfer and production because of the r^2 function.

Foam Muds -- When action is taken to reduce the mud temperature in the hole, it might also be desirable to reduce heat transfer to the mud. The heat flow in mud is relatively low; 0.5 to 1.0 BTU/hr/ft/°F,^{62,83} but during several hours of static conditions it can build up temperatures that are critical to the drilling mud.

A possible solution to the problem of heat transfer is the use of insulating drilling fluid -- foam (Figure 80). There is evidence to indicate that foam mud is an excellent insulator.⁸¹ Their experience in using it in the Arctic to insulate the permafrost is quite conclusive. Some work done in California using steam in secondary recovery⁸⁴ indicates excellent results. The materials are not yet available that would make a stable foam in very high temperatures, but the concept of an insulating drilling fluid is very attractive. While the concept is contrary to some of the basic experience in reducing borehole temperature by circulating a relatively higher heat conductive mud, the use of a poor heat conductor may help limit mud degradation to a lower level, allowing mud properties to be maintained by continual replacement of degraded materials.

Figure 80. Foam as an insulating mud

Faster Trips

Serious gelling problems have been encountered in the Geysers and other geothermal fields during tripping because of the high mud temperatures reached during these trips. Faster trips could significantly reduce the bottomhole mud temperatures as shown in Figure 81. In this example, a 20,000 foot well, the bottom hole temperature is 270°F after circulating for 16 hours. After 1 hour, the bottom hole temperature increases to 310°F, after 16 hours it reaches 380°F which is near the 400°F original temperature. This shows the importance of making faster trips in order to reduce the mud temperature during trips.

Figure 81. Effect of trip time on mud temperature⁶²

Replacement of Mud Components

In drilling a geothermal well, the regular program of mud testing should include an examination of the effect of aging the mud at temperatures to be encountered at completion depth. The equipment for static aging at the drill site is readily available.^{85,86} Based on the results of tests on the aged samples, a program of treatment can be outlined to minimize unexpected changes in mud properties.

Even though the ingredients may lack the desired thermal stability, properties of the mud can be controlled within limits. By following a program of continuous replacement of certain components, adequate performance may be secured without completely changing the type of drilling fluid. The requirement is that the mud "must be thermally stable to the extent that replacement at the surface can offset decomposition downhole."

Heat stability of mud to be left in the hole during trips to change bits, or to conduct electrical logging operations, can be increased by supplemental treatment. The quantity of mud subjected to prolonged heating is relatively small. The cost of treatment, while high on a unit volume basis, is relatively low. By following this practice the useful operational capability of conventional muds has been extended to about 500°F.⁸⁷ If the properties of the mud from the bottomhole

section have been seriously impaired by heat, that small portion of the mud should be discarded. Often the cost of replacement by freshly-prepared mud is less than the cost of reconditioning thermally degraded mud.

Because the rate of degradation of the organic mud ingredients is affected by both temperature and time of heating, the utilization of all of the applicable engineering alternatives may make the continued use of conventional drilling fluids more economical than the substitution of specially-designed muds.

Conclusions

The following conclusions were reached:

- 1) Increasing the specific heat of the mud by removing drill solids or by other means will reduce the mud temperature.
- 2) Increasing the mud circulation rate will reduce the mud temperature, but may cause hole erosion or lost circulation problems.
- 3) Reducing the wellbore annular area will increase the mud velocity and reduce the mud temperature.
- 4) Cooling towers and refrigeration units can be used to cool the mud.
- 5) Insulating the drillpipe or the lower portions of the casing and borehole will reduce the mud temperature.
- 6) Use of wireline retractable bits will allow circulating while drilling and reduce mud thermal degradation problems.
- 7) Use of parasite tubing on the outside of casing will also allow circulation while tripping to replace worn bits, thereby reducing mud degradation problems.
- 8) Use of reelable drillpipe will reduce trip time and allow mud circulation through the pipe while tripping, thereby reducing thermal degradation problems.
- 9) Use of double-walled drillpipe will increase mud velocities and reduce mud temperatures.
- 10) Use of balanced pressure drilling eliminates the need for filter loss control, thereby increasing the temperature capabilities of water base muds.
- 11) Many of these engineering alternative to reduce mud problems could be immediately put into practice.

APPENDIX A

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Data Sheet - 1

Dynamic Test-Sample A Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr		8 hours		16 hours		40 hours		64 hours	
Density, ppg	8.9									
pH	8.7		8.1		7.7		7.7		7.9	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	29	24.5	102	92	115	101	109	101	151	143
300 rpm	16	14	73	66.5	82	72.5	72	76	10.7	104
200 rpm	11.5	10	59	53	64.5	58	59	58	8.4	80.5
100 rpm	6.5	5.5	38	34.5	41.5	38	39	37	55.5	52
6 rpm	1	1	3.5	3	4	3	4	3.5	7	6
3 rpm	0.5	0.5	2.0	1.5	2	1.5	2	2.0	4	3.5
Plastic Viscosity, cp	13	10.5	29	25.5	33	28.5	37	25	44	39
Yield Point, lb/100 sq.ft.	3	3.5	44	41.0	49	44	35	51	63	65
10-sec Gel lb/100 sq.ft.	1	0.5	2.5	2	2.5	2	4	3.0	5	4.0
10-min Gel lb/100 sq.ft.	1	1	7.0	7.0	8.0	8.0	31	20.0	46	41
API Filtrate, ml	7.2		9.6		9.5		12.0		14.1	
HTHP Filtrate										
(30 min),ml	24.4		26.2		30.0		32.0		36.8	
HTHP Filtrate at various time increments										
1 min	6.0		6.0		7.2		7.2		7.6	
3 min	8.2		9.2		11.0		12.4		12.2	
7.5 min	11.6		13.2		15.8		16.4		18.2	
15 min	17.0		16.4		22.2		22.8		25.6	
30 min	24.4		26.2		30.0		32.0		36.8	
45 min	30.4		32.8		36.8		39.2		46.6	
60 min	36.0		37.8		42.8		43.6		53.8	
75 min	40.4		42.8		48.0		-		59.8	
90 min	45.2		47.2		52.4		55.6		65.8	
105 min	49.2		51.4		57.2		60.6		-	
120 min	52.8		56.0		61.6		64.8		76.0	
135 min	56.0		58.4		65.2		68.8		80.6	
150 min	60.4		62.4		69.2		72.0		84.8	
165 min	63.6		65.2		72.4		76.0		88.8	
180 min	66.8		66.4		77.6		79.8		93.2	

Data Sheet - 2

Dynamic Test-Sample B Rolled at 350°F, 300 psi

Hours of Rolling	Original Sample		8 hours		16 hours		40 hours		64 hours	
	0/hr									
Density, ppg	9.0									
pH	9.4		8.6		8.7		8.4		8.5	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	14	13	30	27	31	27	35	27	33	27
300 rpm	7.5	7	22	19	22	18.5	27.5	20	25.5	19.5
200 rpm	6	5	19	16	17.5	14.5	24	18	23	17.5
100 rpm	4	3.5	16.5	13	14.0	11	21	15.5	20	15
6 rpm	1.5	1.5	16	12	10	8	17	13	16	12.5
3 rpm	1	1	14	11	9	7	12	10	12	9.5
Plastic Viscosity, cp	6.5	6	8	8	9	8.5	7.5	7	7.5	7.5
Yield Point, lb/100 sq.ft.	1	1	14	11	13	10.0	20	13	18	12
10-sec Gel lb/100 sq.ft.	2	1.5	9.0	8.0	7.0	7.0	11	8	11	9.0
10-min Gel lb/100 sq.ft.	5.5	6	10.0	5.0	8.0	8.0	10	9	10.5	9.0
API Filtrate, ml	5.0		4.8		5.0		5.0		5.0	
HTHP Filtrate (30 min), ml	18.8		22.0		25.6		31.8		22.4	
HTHP Filtrate at various time increments										
1 min	5.6		5.2		7.4		17.6		5.2	
3 min	7.2		8.4		10.0		21.2		8.0	
7.5 min	10.4		12.4		14.4		24.0		11.8	
15 min	14.8		16.8		19.6		27.2		16.8	
30 min	18.8		22.0		25.6		31.8		22.4	
45 min	24.8		26.8		30.4		35.2		28.0	
60 min	27.6		30.8		34.4		38.4		32.0	
75 min	30.4		34.0		38.0		41.4		35.6	
90 min	33.2		36.8		41.6		44.4		38.8	
105 min	35.6		39.2		44.2		46.8		42.0	
120 min	38.0		42.0		46.8		49.2		44.4	
135 min	40.4		44.4		49.2		51.2		46.8	
150 min	42.4		46.4		51.6		53.4		49.2	
165 min	44.4		49.0		54.0		55.2		51.2	
180 min	46.4		50.0		56.4		59.0		53.8	

Data Sheet - 3

Dynamic Test-Sample C Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr.		8 hours		16 hours		40 hours		64 hours	
Density, ppg	9.1									
pH	10.1		8.7		8.6		8.2		8.3	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Reading:										
600 rpm	6.5	5	18	17	22	22	19.5	16.5	24.5	23.0
300 rpm	3.5	3	11	10	14.5	12.5	11.0	9.5	15.0	14.0
200 rpm	2.5	2	8	7.5	11	9	8.0	7.0	10.5	10.0
100 rpm	1.5	1	4.5	4.0	6.5	6	4.5	4	6.0	6.0
6 rpm	0.5	0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
3 rpm	0	0	0	0	0	0	0	0	0	0
Plastic Viscosity, cp	3	2	7	7	7.5	9.5	8.5	7.0	9.5	9.0
Yield Point, lb/100 sq.f	0.5	1	4	3	7	3	2.5	2.5	5.5	5.0
10-sec Gel lb/100 sq.ft.	0	0	0.5	0.5	0.5	0.5	0.5	1.0	0.5	0.5
10-min Gel lb/100 sq.ft.	1	1	1	1	1.5	1.5	2.0	2.0	1.5	2.0
API Filtrate, ml	3.4		5.6		5.7		6.4		6.5	
HTHP Filtrate (30 min), ml	15.8		19.4		20.4		20.2		21.4	
HTHP Filtrate at various time increments										
1 min	4.0		5.6		6.4		5.6		6.0	
3 min	6.2		8.0		8.6		8.0		8.4	
7.5 min	8.8		10.4		11.2		11.2		11.6	
15 min	11.2		14.2		15.6		15.2		16.0	
30 min	15.8		19.4		20.4		20.2		21.4	
45 min	20.0		23.2		24.4		24.4		25.6	
60 min	22.4		26.0		27.4		27.6		28.8	
75 min	24.8		29.2		30.2		30.8		31.6	
90 min	27.2		32.4		33.0		33.6		34.4	
105 min	29.6		34.0		35.2		36.0		36.8	
120 min	31.4		36.0		37.6		38.2		39.2	
135 min	33.0		38.2		39.6		40.4		41.2	
150 min	35.2		40.0		41.2		42.6		43.2	
165 min	36.4		42.0		43.2		44.8		44.8	
180 min	38.0		43.2		45.0		46.8		46.8	

Data Sheet - 4

Dynamic Test-Sample D Rolled at 350°F, 300 psi

Hours of Rolling	Original Sample 0/hr		8 hours		16 hours		40 hours		64 hours	
Density, ppg	9.1									
pH	9.8		7.5		7.6		7.6		7.4	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	11.5	11	12	11	22	22.5	35.5	34	31.5	31.5
300 rpm	7.5	7.5	6.5	6	13.5	14	23	22.5	20.5	20
200 rpm	6	6	5	4	10	10.5	17.5	17.5	15.5	15.5
100 rpm	4.5	4	2.5	2.5	6	6.5	10.5	11	9.5	9.5
6 rpm	2	2	.5	.5	.5	.5	1.5	1.5	1	1.5
3 rpm	1.5	1.5	.5	0	.5	.5	1	1	.5	1
Plastic Viscosity, cp	4	3.5	5.5	5	8.5	8.5	12.5	11.5	11.0	11.5
Yield Point, lb/100 sq.ft.	3.5	4	1	1	5	5.5	10.5	11	9.5	8.5
10-sec Gel lb/100 sq.ft.	1.5	1.5	0	0	0.5	0.5	1.5	2	1.0	1.5
10-min Gel lb/100 sq.ft.	3.5	3.5	1.5	1.5	3.5	4	5	5	5	5
API Filtrate, ml	5.6		8.4		10.2		9.8		12.6	
HTHP Filtrate										
(30 min), ml	30.0		31.8		28.6		28.4		28.4	
HTHP Filtrate at various time increments										
1 min	11.2		9.6		9.6		8.8		7.8	
3 min	14.4		13.6		12.2		12.4		10.2	
7.5 min	18.6		18.0		17.0		16.4		16.0	
15 min	23.0		24.0		21.4		21.6		21.6	
30 min	30.0		31.8		28.6		28.4		28.4	
45 min	34.6		36.4		32.2		34.0		34.0	
60 min	40.0		41.6		39.0		39.0		38.4	
75 min	42.4		45.8		43.2		43.6		43.2	
90 min	46.0		50.0		46.8		46.8		47.0	
105 min	48.8		53.6		50.0		50.0		50.0	
120 min	51.6		56.8		53.4		53.6		53.2	
135 min	54.0		59.4		56.4		56.4		56.0	
150 min	56.8		62.0		59.4		59.4		59.2	
165 min	59.6		64.2		61.6		62.0		61.8	
180 min	61.2		66.4		64.4		64.6		64.4	

Data Sheet - 5

Dynamic Test-Sample E Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr		8 hours		16 hours		40 hours		64 hours	
Density, ppg	8.7									
pH	10.3		9.2		9.1		9.2		9.1	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	37	30	13.0	11.5	16	15	11	9.5	14	12
300 rpm	22	18	7.5	6.5	9	8	6.5	5.5	8	7
200 rpm	17	13.5	5.5	5	6.5	6	4.5	4	6	5
100 rpm	10	8	3.0	3.0	4	3.5	3	2.5	3.5	3
6 rpm	2	1.5	0.5	0.5	0.5	0.5	0.5	0.5	1	0.5
3 rpm	1.5	1	0	0	0	0	0	0	0	0
Plastic Viscosity, cp	15	12	5.5	5	7	7	4.5	4	6	5
Yield Point, lb/100 sq.ft	7	6	2.0	1.5	2	1	2	1.5	2	2
10-sec Gel lb/100 sq.ft.	2	2	1	1	1	0.5	0.5	0.5	1	0.5
10-min Gel lb/100 sq.ft.	4	3	1	1	1	1	1	0.5	1	1
API Filtrate, ml	8.9		13.6		14.6		13.4		13.2	
HTHP Filtrate										
(30 min), ml	34.0		45.6		47.0		50.4		46.4	
HTHP Filtrate at various time increments										
1 min	7.0		9.2		8.8		9.0		8.4	
3 min	11.6		15.2		14.8		15.4		14.0	
7.5 min	17.0		23.8		24.0		25.2		22.6	
15 min	24.4		34.0		34.4		35.6		32.4	
30 min	34.0		45.6		47.0		50.4		46.4	
45 min	41.6		56.0		60.0		61.4		56.0	
60 min	48.2		66.6		69.6		70.4		65.4	
75 min	54.8		74.2		79.0		-		72.8	
90 min	60.2		82.0		86.0		92.4		78.8	
105 min	64.6		88.0		92.8		98.4		85.6	
120 min	69.6		94.4		99.2		104.4		91.6	
135 min	73.8		100.0		105.2		110.0		99.2	
150 min	78.2		104.4		110.4		114.4		-	
165 min	82.4		110.2		115.6		119.4		107.2	
180 min	85.4		115.2		120.8		124.4		111.6	

Data Sheet - 6

Dynamic Test-Sample F Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr.	8 hours		16 hours		40 hours		64 hours	
Density, ppg	18.1								
pH	9.5	8.9		8.3		8.4		8.3	
Test Temperature, °F	125	150	125	150	125	150	125	150	125
Fann V.G. Meter Readings									
600 rpm	98	77	87	82	97	93.5	113.5	104	146
300 rpm	50	39.5	45	41	51.5	49.5	62	55	89
200 rpm	34	27	30.5	27.5	35	33	42.5	37.5	63.5
100 rpm	18	14.5	15.5	14	18	17	22	19	33.5
6 rpm	2	1.5	1.5	1.5	1.5	1	2	1.5	2
3 rpm	1	1	1	1	1.0	1	1.5	1.0	1.5
Plastic Viscosity, cp	48	37.5	42	41	45.5	44.0	51.5	49.0	57
Yield Point, lb/100 sq.ft.	2	2	3	0	6.0	5.5	10.5	6.0	32
10-sec Gel lb/100 sq.ft.	1.5	1	1	1	1.5	1.5	2	1.5	2
10-min Gel lb/100 sq.ft.	2	2	3	2	2.0	2.0	2	2.0	3.5
API Filtrate, ml	1.2		2.0		2.2		2.6		2.8
HTHP Filtrate (30 min), ml	8.0		8.4		8.8		14.4		24.0
HTHP Filtrate at various time increments									
1 min	1.8		2.2		2.4		7.0		3.6
3 min	3.2		3.2		3.6		8.0		6.8
7.5 min	4.0		4.6		5.2		9.6		11.6
15 min	5.4		6.2		6.8		11.6		17.4
30 min	8.0		8.4		8.8		14.4		24.0
45 min	9.8		10.0		10.8		16.8		27.6
60 min	11.6		11.6		12.4		18.8		30.0
75 min	13.2		12.8		14.4		20.8		32.4
90 min	14.8		14.0		16.4		22.8		34.8
105 min	16.2		15.2		18.4		24.6		37.2
120 min	17.2		16.4		20.0		26.4		39.4
135 min	18.2		17.4		22.0		28.0		41.2
150 min	19.2		18.4		23.6		29.6		43.2
165 min	20.4		19.2		25.2		31.2		45.2
180 min	21.4		20.2		27.2		32.8		47.2

Data Sheet - 7

Dynamic Test-Sample G Rolled at 350°F, 300 psi

Hours of Rolling	Original Sample		8 hours		16 hours		40 hours		64 hours	
	0/hr									
Density, ppg	18.2									
pH	9.5		7.9		7.6		7.8		7.5	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	66.5	52.5	85	82	96	86	108	102	107	97
300 rpm	33.5	26.5	43	41	48	43	75	70	58	52
200 rpm	22	16.5	29	27	32	28.5	48	45	39.5	34.5
100 rpm	11.5	9	14	14	16	14	33	32	19.5	17
6 rpm	1	1	1.5	1	1.5	1.5	15	12	1.5	1.5
3 rpm	.5	.5	1	.5	1	1	10	8	1	.5
Plastic Viscosity, cp	33	26	42	44	48	43	33	32	49	45
Yield Point, lb/100 sq.ft.	.5	.5	10	0	0	0	42	38	9	7
10-sec Gel lb/100 sq.ft.	1.5	1	1	1	1.5	1	25	19	2	2
10-min Gel lb/100 sq.ft.	14	16	2	2	3.5	3	28	52	12	12
API Filtrate, ml	3.8		8.0		8.0		9.0		16.4	
HTHP Filtrate										
(30 min), ml	26.8		22.6		24.0		24.0		36.4	
HTHP Filtrate at various time increments										
1 min	8.0		7.2		7.6		10.0		19.0	
3 min	11.8		10.4		11.6		12.0		23.8	
7.5 min	16.4		14.2		15.6		15.0		28.0	
15 min	20.8		17.6		18.8		19.0		32.0	
30 min	26.8		22.6		24.0		24.0		36.4	
45 min	31.8		26.8		28.2		28.0		40.4	
60 min	36.4		30.0		32.0		31.0		43.6	
75 min	40.4		32.8		34.8		34.0		46.2	
90 min	43.2		35.6		37.2		37.0		48.6	
105 min	46.2		38.4		39.6		39.0		51.2	
120 min	49.6		40.4		41.6		40.6		53.2	
135 min	51.8		42.4		43.6		42.0		55.0	
150 min	54.0		44.4		45.6		44.0		56.8	
165 min	56.6		46.4		47.2		45.8		58.8	
180 min	59.6		48.4		49.0		47.6		60.4	

Data Sheet - 8

Dynamic Test-Sample H Rolled at 350°F, 300 psi

Hours of Rolling	Original Sample		8 hours		16 hours		40 hours		64 hours	
	0/hr									
Density, ppg	18.2									
pH	11.0		9.4		8.9		8.8		8.6	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	230	194	208.5	190	OS*	OS*	OS*	OS*	OS*	OS*
300 rpm	136	116.5	129	118.5	191	145	244	205	OS*	230
200 rpm	101	87	97	89.5	126	98	166	141	190	162
100 rpm	62	54.5	58	53	66	53.5	86.5	74	102	87
6 rpm	12	12	9	8.5	9	7.5	10.5	9	12	11
3 rpm	9	9.5	6.5	6.5	5.5	5	7.5	7	8	7
Plastic Viscosity, cp	94	77.5	79.5	71.5	-	-	-	-	-	-
Yield Point, lb/100 sq.ft.	42	39.0	49.5	47.0	-	-	-	-	-	-
10-sec Gel lb/100 sq.ft.	10.5	10.5	9.5	8.5	6.5	5.5	8	7	9	8
10-min Gel lb/100 sq.ft.	38.5	42.5	26.0	27	18	18	19	19	22	21
API Filtrate, ml	1.6		2.6		2.4		2.4		2.4	
HTHP Filtrate										
(30 min), ml	6.8		7.0		9.2		8.4		10.8	
HTHP Filtrate at various time increments										
1 min	1.6		2.0		2.4		2.0		2.8	
3 min	2.4		2.8		4.0		3.2		4.0	
7.5 min	3.4		4.0		5.2		4.4		5.6	
15 min	4.8		5.4		6.4		6.0		7.6	
30 min	6.8		7.0		9.2		8.4		10.8	
45 min	8.4		8.4		10.8		10.0		13.2	
60 min	9.6		9.6		12.4		11.6		15.2	
75 min	11.2		10.6		13.6		13.2		16.8	
90 min	12.2		11.6		14.8		14.4		18.4	
105 min	13.2		12.4		16.0		15.2		19.6	
120 min	14.4		13.2		17.0		16.4		21.0	
135 min	15.2		14.0		18.0		17.6		22.2	
150 min	16.0		14.8		19.0		18.0		-	
165 min	16.8		15.6		20.0		19.0		24.4	
180 min	17.6		16.4		21.0		20.0		25.4	

* O.S. - Off scale on a Fann VG Meter equipped with a one multiplier spring.

Data Sheet - 9

Dynamic Test-Sample 1 Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr.	8 hours		16 hours		40 hours		64 hours	
Density, ppg	18.2								
pH	9.1	8.4		8.05		8.1		7.9	
Test Temperature, ⁰ F	125	150	125	150	125	150	125	150	125
Fann V.G. Meter Readings									
600 rpm	72	66	144	135	179.5	155	213.5	185	188.5
300 rpm	40.5	34.5	92	93	115	95	132	112	124.5
200 rpm	28.5	24.5	70	70	84.5	69.5	97.5	81	99
100 rpm	16.5	14	40.5	41	48	39	59	46	70
6 rpm	3.5	2.5	6	6	8.5	5.5	13	8	41
3 rpm	2	1.5	4	4	6	4	10	6.5	38
Plastic Viscosity, cp	31.5	31.5	52	42	64.5	60	81.5	73	64
Yield Point, lb/100 sq.ft.	9	3.0	40	51	50.5	35	50.5	39	60.5
10-sec Gel lb/100 sq.ft.	4	3.5	7	6.5	7	6	15	9.5	36
10-min Gel lb/100 sq.ft.	6	6	18	15	27	29	52.5	34	78
API Filtrate, ml	2.4	5.1			5.5		10.0		10.8
HTHP Filtrate (30 min), ml	10.0	56.6			36.0		57.0		51.4
HTHP Filtrate at various time increments									
1 min	4.0	8.8			3.6		10.0		9.2
3 min	4.6	16.2			7.2		16.6		16.4
7.5 min	5.8	26.2			13.6		27.2		26.4
15 min	7.4	42.0			22.0		39.0		37.2
30 min	10.0	56.6			36.0		57.0		51.4
45 min	11.6	70.8			46.4		69.4		60.8
60 min	13.2	81.0			56.8		81.0		69.2
75 min	15.2	89.4			65.0		91.4		77.6
90 min	16.8	98.8			73.0		101.0		83.4
105 min	18.0	106.8			80.8		108.6		89.6
120 min	19.0	114.2			84.2		117.0		95.2
135 min	20.0	119.8			88.0		124.2		100.8
150 min	20.8	122.8			100.0		131.4		105.6
165 min	21.6	126.8			106.0		137.4		109.6
180 min	22.8	130.6			111.0		144.4		114.8

Data Sheet - 10

Dynamic Test-Sample J Rolled at 350°F, 300 psi

Hours of Rolling	Original Sample 0/hr		8 hours		16 hours		40 hours		64 hours	
Density, ppg	18.1									
pH	10.0		8.3		8.3		7.8		8.0	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	91	72	151.5	132	168	151	176	150.5	139.5	124
300 rpm	50.5	37	91.5	78	110	98.5	116	100	91	82
200 rpm	35.5	26.5	66.5	56.5	84	75	90.5	78.5	71	63
100 rpm	20.0	15	38	32	50	44.5	56	47	44	38
6 rpm	3	2.5	3.5	3	4	3.5	6	4	5	3.5
3 rpm	2	1.5	2	1.5	2	1.5	3.5	2	3	2
Plastic Viscosity, cp	40.5	35	60	54	58	52.5	60	50.5	48.5	42
Yield Point, lb/100 sq.ft.	10	2	31.5	24	52	46	56	49.5	42.5	40
10-sec Gel lb/100 sq.ft.	3	3	3	2.5	3.5	2.5	5	4	4.5	3.5
10-min Gel lb/100 sq.ft.	5	5	10.5	9	17	17	26	24	22	19
API Filtrate, ml	0.9		1.3		2.2		2.0		2.3	
HTHP Filtrate										
(30 min), ml	5.6		6.0		5.6		6.2		5.6	
HTHP Filtrate at various time increments										
1 min	1.0		1.6		0.8		1.6		0.8	
3 min	2.0		2.2		1.8		2.2		1.8	
7.5 min	2.8		3.2		2.8		3.4		2.4	
15 min	3.6		4.2		4.0		4.4		4.0	
30 min	5.6		6.0		5.6		6.2		5.6	
45 min	7.2		7.2		7.0		7.6		7.0	
60 min	8.8		8.4		8.2		9.0		8.4	
75 min	10.0		9.6		9.0		10.2		9.4	
90 min	11.2		10.6		10.0		11.2		10.2	
105 min	12.2		11.4		10.8		12.2		11.2	
120 min	13.2		12.2		11.6		13.2		12.0	
135 min	14.0		13.2		12.4		14.0		12.8	
150 min	15.2		13.6		13.2		14.6		13.4	
165 min	16.0		14.4		13.8		15.4		13.8	
180 min	17.0		15.2		14.6		16.0		14.0	

Data Sheet - 11

Dynamic Test-Sample K Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr.		8 hours		16 hours		40 hours		64 hours	
Density, ppg	17.8									
Electrical Stability, Volts	1172		870		620		1340		816	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	245	150	OS*	OS*	OS*	OS*	OS*	OS*	OS*	OS*
300 rpm	139	90	295	265	OS*	OS*	OS*	OS*	OS*	OS*
200 rpm	102.5	68.5	226	200	OS*	OS*	OS*	OS*	OS*	OS*
100 rpm	63	44	152	133	OS*	OS*	OS*	OS*	OS*	OS*
6 rpm	17	14	38	37	97.5	103	166	161	182	180
3 rpm	14	12	31	30	77	83	137	133	142	142
Plastic Viscosity, cp	106	60	-	-	-	-	-	-	-	-
Yield Point, lb/100 sq.ft	33	30	-	-	-	-	-	-	-	-
10-sec Gel lb/100 sq.ft	19	16	32	30	66	63	125	122	145	160
10-min Gel lb/100 sq.ft	23.5	20	40	37	85	75	140	134	158	168
API Filtrate, ml	None		None		0.8		0.4		0.4	
HTHP Filtrate (30 min), ml	0.4		0.8		2.2		2.0		1.6	
HTHP Filtrate at various time increments										
1 min	0.0		0.4		0.0		0.2		<0.2	
3 min	0.0		0.4		0.2		0.6		0.2	
7.5 min	0.0		0.4		0.4		1.0		0.4	
15 min	0.2		0.6		0.8		1.4		0.8	
30 min	0.4		0.8		2.2		2.0		1.6	
45 min	0.8		1.0		2.8		2.4		2.4	
60 min	1.0		1.2		3.4		2.8		2.8	
75 min	1.6		1.2		3.8		3.2		3.2	
90 min	2.0		1.8		4.2		3.8		3.4	
105 min	2.4		2.8		4.4		4.6		4.0	
120 min	2.8		4.4		4.6		5.0		4.4	
135 min	3.2		6.4		5.0		5.6		4.8	
150 min	3.4		8.4		5.6		6.0		5.4	
165 min	3.6		10.8		5.8		6.4		6.0	
180 min	3.8		12.8		6.0		7.0		6.6	

*O.S. - Off scale on a Fann V.G Meter equipped with a one multiplier spring.

Data Sheet - 12

Dynamic Test-Sample L Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr.	8 hours		16 hours		40 hours		64 hours	
Density, ppg	18.1								
Electrical Stability, Volts	800	944		1050		1000		960	
Test Temperature, ⁰ F	125	150	125	150	125	150	125	150	125
Fann V.G. Meter Readings									
600 rpm	216	153	295	240	OS*	240	OS*	OS*	OS*
300 rpm	118	84.5	168	136	181.5	146	204.5	151	218
200 rpm	83	60	120	96.5	130	99	143	107.5	149
100 rpm	45	33.5	65	58	71	54	78	58	80
6 rpm	5	4	7	5	6	5	6.5	5.5	6.5
3 rpm	3	3	4	5	3.5	3	3.5	3.0	4
Plastic Viscosity, cp	98	68.5	127	104	-	94	-	-	-
Yield Point, lb/100 sq.ft.	20	16.0	51	32	-	52	-	-	-
10-sec Gel lb/100 sq.ft.	7.5	7	6	4.5	5	3.5	4.5	4	4
10-min Gel lb/100 sq.ft.	24	24	18	19	17.5	14	16	16	13
API Filtrate, ml	None		None		None		None		None
HTHP Filtrate (30 min), ml	0.2		<0.2		0.2		0.4		<0.2
HTHP Filtrate at various time increments									
1 min	0.0		0.0		0.0		0.0		0.0
3 min	0.0		0.0		0.0		0.0		0.0
7.5 min	0.0		0.0		0.0		0.0		0.2
15 min	0.0		0.0		0.0		0.0		0.4
30 min	0.2		<0.2		0.2		0.4		<0.2
45 min	0.6		0.2		0.4		0.8		0.4
60 min	0.8		0.4		0.6		1.2		0.6
75 min	1.0		0.6		0.8		1.4		0.8
90 min	1.2		1.0		1.0		1.6		1.2
105 min	1.4		1.4		1.2		1.6		1.6
120 min	1.6		1.6		1.4		1.8		1.8
135 min	1.8		1.8		1.6		2.0		2.0
150 min	2.0		2.0		1.6		2.2		2.4
165 min	2.0		2.0		2.0		2.4		2.6
180 min	2.2		2.2		2.2		2.6		2.8

* O.S. - Off scale on a Fann VG Meter equipped with a one multiplier spring.

Data Sheet - 13

Dynamic Test-Sample M Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr.		8 hours		16 hours		40 hours		64 hours	
Density, ppg	18.2									
Electrical Stability, Volts	1080		1396		1860		1460		1350	
Test Temperature, ⁰ F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	270	17.1	OS*	OS*	OS*	OS*	OS*	OS*	OS*	OS*
300 rpm	154	95.5	231	210	234	161	OS*	OS*	OS*	OS*
200 rpm	112	68	166	149	167	120	247	204	OS*	OS*
100 rpm	63.5	39	94	84	94	65	142	117.5	253	194
6 rpm	9.0	6	13.5	27	12	9.5	29.5	26.5	79	59
3 rpm	7.5	4	10.5	13	8.5	6	24.5	22.5	71	54
Plastic Viscosity, cp	116	75.5	-	-	-	-	-	-	-	-
Yield Point, lb/100 sq.ft	38	20	-	-	-	-	-	-	-	-
10-sec Gel lb/100 sq.ft.	8.5	6	14	14	12	8.5	32	27	81	65
10-min Gel lb/100 sq.ft.	20	13	21	24	25.5	20.5	52	52	100	94
API Filtrate, ml	None		None		None		0.0		0.0	
HTHP Filtrate (30 min), ml	0.8		4.4		1.2		4.2		26.4	
HTHP Filtrate at various time increments										
1 min	0.0		0.6		0.0		2.0		10.4	
3 min	0.0		1.6		0.0		2.4		15.4	
7.5 min	<0.2		2.2		<0.2		2.8		21.6	
15 min	0.4		3.2		0.8		3.4		25.2	
30 min	0.8		4.4		1.2		4.2		26.4	
45 min	1.2		5.4		1.6		4.6		27.2	
60 min	1.2		6.4		2.2		5.4		28.0	
75 min	1.8		7.2		2.4		5.8		28.4	
90 min	2.2		8.0		2.8		6.2		28.6	
105 min	2.4		8.6		3.2		6.6		29.0	
120 min	2.4		9.6		3.6		6.8		29.2	
135 min	2.8		10.4		3.8		7.2		29.4	
150 min	3.2		11.0		4.0		7.2		29.6	
165 min	3.4		12.2		4.2		7.6		30.0	
180 min	3.6		13.2		4.4		7.8		30.4	

*0.S. - Off scale on a Fann VG Meter equipped with a one multiplier spring.

Data Sheet - 14

Dynamic Test-Sample N Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr.		8 hours		16 hours		40 hours		64 hours	
Density, ppg	18.2									
Electrical Stability, Volts	1350		900		640		590		700	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	185	145	260	222	219	175	234	191	267	220
300 rpm	106	83	153	131	116	91.5	125.5	101	144	117
200 rpm	77	62	110	94	80	62.5	86.5	69.5	99.5	80.5
100 rpm	47	38.5	61	53	41.5	33	45	36.5	52.5	42.5
6 rpm	11	10	7	6	3.5	3	3.5	3	4	3.5
3 rpm	9	8	4	4	2	1.5	2.5	2	2.5	2
Plastic Viscosity, cp	79	62	107	91	103	83.5	108.5	90	123	103
Yield Point, lb/100 sq. ft.	27	21	46	40	13	8	17	11	17	14
10-sec Gel lb/100 sq. ft.	11	10	6	6	3	3	3	3	3	3
10-min Gel lb/100 sq. ft.	15	14	16	15	5	5	4	4	4	4.5
API Filtrate, ml	None		None		None		None		None	
HTHP Filtrate (30 min), ml	0.4		0.2		0.8		0.4		0.8	
HTHP Filtrate at various time increments										
1 min	0.0		0.0		0.0		0.0		0.0	
3 min	0.0		0.0		0.0		0.0		0.0	
7.5 min	0.0		0.0		0.0		0.0		0.0	
15 min	<0.2		0.0		<0.2		<0.2		0.2	
30 min	0.4		0.2		0.8		0.4		0.8	
45 min	1.0		0.8		1.0		0.8		1.2	
60 min	1.2		1.2		1.2		1.0		1.4	
75 min	1.6		1.6		1.4		1.2		1.6	
90 min	1.8		1.8		1.8		1.4		2.0	
105 min	2.2		2.0		2.0		1.6		2.2	
120 min	2.6		2.4		2.2		1.8		2.4	
135 min	2.8		2.6		2.4		2.0		2.8	
150 min	3.0		2.8		2.6		2.2		3.0	
165 min	3.2		2.8		2.8		2.4		3.2	
180 min	3.4		3.2		3.2		2.6		3.6	

Data Sheet - 15

Dynamic Test-Sample 0 Rolled at 350⁰F, 300 psi

Hours of Rolling	Original Sample 0/hr.		8 hours		16 hours		40 hours		64 hours	
Density, ppg	18.3									
Electric Stability, Volts	1520		1500		1470		1400		1690	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	162	129	183	148	160	128	100	81	113.5	85
300 rpm	94	75	105	85	90	71	53	43	59	43.5
200 rpm	68.5	55	75	62	63.5	51	37	30	40	30
100 rpm	40.5	33	44	36	35.5	29	20	16.5	21	16
6 rpm	5	4.5	5.5	4	4	3	2	1.5	2	1.5
3 rpm	3	2.5	3.5	3	2	2	1	1	1	.5
Plastic Viscosity, cp	68	54	78	63	70	57	47	38	54.5	41.5
Yield Point, lb/100 sq. ft	26	21	27	22	20	14	6	5	4.5	2
10-sec Gel lb/100 sq. ft	4.5	4	4	4	3	3	2	1.5	2.0	1.5
10-min Gel lb/100 sq. ft	9.5	9.5	8.5	8	5	4.5	3.5	2.5	3.0	2.5
API Filtrate, ml	None		0.0		0.0		0.0		0.0	
HTHP Filtrate (30 min), ml	2.4		3.6		3.0		2.0		2.4	
HTHP Filtrate at various time increments										
1 min	0.0		0.0		0.0		0.0		0.0	
3 min	<0.2		0.4		0.6		0.4		0.8	
7.5 min	0.4		1.4		1.2		1.0		1.2	
15 min	1.6		2.0		2.0		1.6		1.6	
30 min	2.4		3.6		3.0		2.0		2.4	
45 min	3.0		4.4		3.2		2.4		2.8	
60 min	3.6		4.8		3.8		3.0		3.2	
75 min	4.0		5.2		4.4		3.4		4.0	
90 min	4.4		5.6		4.8		3.8		4.4	
105 min	4.8		6.0		5.2		4.2		5.4	
120 min	5.2		6.4		5.6		4.4		5.6	
135 min	5.6		6.8		5.8		4.6		6.0	
150 min	6.0		7.2		6.2		4.8		6.4	
165 min	6.4		7.4		6.4		5.4		6.8	
180 min	6.8		7.6		6.6		5.8		7.2	

APPENDIX B

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Data Sheet - 16

Sample A Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Top Separation	None		None		None		None	
Density, lb/gal	8.9							
Shear Strength, lb/100 sq.ft.			600		40		300	
pH	8.7		8.6		8.1		8.4	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	29	24.5	101.5	61.5	85	79	78.5	88.5
300 rpm	16	14	62	39	58	55	47	59
200 rpm	11.5	10	47	30	45	48	33.5	44.5
100 rpm	6.5	5.5	30	19	33	40.5	24	32
6 rpm	1	1	4.5	2.5	22	30	7	6.5
3 rpm	0.5	0.5	3.0	1.5	21	29	6.5	6
Plastic Viscosity, cp	13.0	10.5	39.5	22.5	27	24	31.5	29.5
Yield Point, lb/100 sq.ft.	3.0	3.5	22.5	16.5	31	31	15.5	29.5
10-sec Gel lb/100 sq.ft.	1	0.5	5	3	29	49	4	7
10-min Gel lb/100 sq.ft.	1	1	33	26	63	66	43	47
API Filtrate, ml	7.2		20.6		21.8		24.3	
HTHP Filtrate (30 min), ml	24.4		34.0		58.4		73.6	
HTHP Filtrate at various time increments								
1 min	6.0		9.0		9.6		10.4	
3 min	8.2		16.0		16.0		21.2	
7.5 min	11.6		20.4		27.8		34.8	
15 min	17.0		-		40.0		50.8	
30 min	24.4		34.0		58.4		73.6	
45 min	30.4		64.0		73.6		90.4	
60 min	36.0		73.0		86.0		104.8	
75 min	40.4		85.0		97.6		117.2	
90 min	45.2		91.0		106.0		128.8	
105 min	49.2		98.0		117.4		140.0	
120 min	52.8		105.0		128.8		150.0	
135 min	56.0		111.0		blew		160.0	
150 min	60.4		119.0		out		169.2	
165 min	63.6		126.0		at		178.4	
180 min	66.8		131.0		120 min.		187.0	

Data Sheet - 17

Sample B Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Top Separation			None		None		None	
Density, lb/gal	9.0							
Shear Strength, lb/100 sq. ft.			78		10		10	
pH	9.4		8.5		8.1		8.1	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	14	13	42	39	35.5	35.5	36	38
300 rpm	7.5	7	31	29	26.5	26	27.5	30
200 rpm	6	5	27	26	22	21.5	24	24
100 rpm	4	3.5	23	22	17.5	17.5	19.5	19
6 rpm	1.5	1.5	15	14	9.5	9.5	11	11.5
3 rpm	1	1	14	14	6.5	6	6.5	7
Plastic Viscosity, cp	6.5	6	11	10	9	9.5	8.5	8
Yield Point, lb/100 sq. ft	1	1	20	19	17.5	16.5	19	22
10-sec Gel lb/100 sq. ft	2	1.5	16	16	5	6	6	5.5
10-min Gel lb/100 sq. ft	5.5	6.0	19	18	5	6	6	6.5
API Filtrate, ml	5.0		6.0		30ml, blowout 3 min.		17	
HTHP Filtrate (30 min), ml	18.8		22.0		-		55.0	
HTHP Filtrate at various time increments								
1 min	5.6		5.6		34.0		10.0	
3 min	7.2		8.0		61.4		18.0	
7.5 min	10.4		11.6		98.0		29.0	
15 min	14.8		16.0		130.0		39.6	
30 min	18.8		22.0		-		55.0	
45 min	24.8		27.6		-		67.0	
60 min	27.6		30.8		-		78.0	
75 min	30.4		34.2		-		86.4	
90 min	33.2		37.6		-		96.0	
105 min	35.6		40.8		-		103.0	
120 min	38.0				-		110.0	
135 min	40.4		45.8		blew out in 17 minutes		116.0	
150 min	42.4		48.0		final vol 142.0		122.0	
165 min	44.4		51.4				128.0	
180 min	46.4		52.8				134.0	

Data Sheet - 18

Sample C Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Top Separation			None		None		None	
Density, lb/gal	9.1							
Shear Strength, lb/100 sq ft.			130		360		10	
pH	10.1		8.2		8.5		8.3	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	6.5	5	22	19	52	38	22	20
300 rpm	3.5	3	12.5	10	43	32	14	11.5
200 rpm	2.5	2	9	7	39	29	11	8.5
100 rpm	1.5	1	4.5	3.5	34	25	7	5
6 rpm	.5	0	0.5	0	25	21	1.0	0.5
3 rpm	.5	0	0	0	18	20	0.5	0
Plastic Viscosity, cp	3	2	9.5	9	9	6	8	8.5
Yield Point, lb/100 sq.ft.	.5	1	3	1	34	26	6	3
10-sec Gel lb/100 sq.ft.	0	0	0	0	20	15	0.5	0.5
10-min Gel lb/100 sq.ft.	1	1	1	1	25	22	5.5	4.5
API Filtrate, ml	3.4		9.1		54.9		41.0	
HTHP Filtrate (30 min), ml	15.8		23.2		103.0		67.4	
HTHP Filtrate at various time increments								
1 min	4.0		4.8		18.0		15.8	
3 min	6.2		9.0		33.0		25.6	
7.5 min	8.8		13.0		58.0		31.4	
15 min	11.2		17.6		75.0		49.6	
30 min	15.8		23.2		103.0		67.4	
45 min	20.0		28.4		119.0		81.0	
60 min	22.4		32.8		135.0		90.4	
75 min	24.8		36.4		149.0		103.2	
90 min	27.2		39.6		159.0		112.0	
105 min	29.6		43.0		171.0		120.4	
120 min	31.4		45.6		180.0		128.4	
135 min	33.0		48.0		193.0		136.4	
150 min	35.2		50.6		-		140.4	
165 min	36.4		53.2		206.0		149.6	
180 min	38.0		55.4		212.0		156.4	

Data Sheet - 19

Sample D Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Top Separation					None		None	
Density, lb/gal	9.1							
Shear Strength, lb/100 sq. ft.					450		850	
pH	9.8		8.0		7.8		7.9	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	11.5	11.0	286	273	OS	OS	272	260
300 rpm	7.5	7.5	264	258	OS	OS	268	242
200 rpm	6	6	248	250	OS	OS	262	238
100 rpm	4.5	4	244	234	OS	OS	258	232
6 rpm	2	2	60	51	100	79	71	78
3 rpm	1.5	1.5	45	38	95	78	64	70
Plastic Viscosity, cp	4	3.5	22	15	-	-	4	18
Yield Point, lb/100 sq. ft..	3.5	4	242	243	-	-	264	224
10-sec Gel lb/100 sq. ft.	1.5	1.5	43	36	75	80	55	70
10-min Gel lb/100 sq. ft.	3.5	3.5	43	36	70	100	58	70
API Filtrate, ml	5.6		48.3		28.0*		31.2*	
HTHP Filtrate (30 min), ml	30.0		76.0		*blew out in 14.5 min.		*blew out in 14 min.	
HTHP Filtrate at various time increments								
1 min	11.2		13.4		14.8		30	
3 min	14.4		24.0		26.0		42	
7.5 min	18.6		39.6		50.6			
15 min	23.0		54.0		71.1			
30 min	30.0		76.0					
45 min	34.6		93.0		blew out in		blew out	
60 min	40.0		107.0		~15 minutes		in 3 min.	
75 min	42.4		121.0					
90 min	46.0		130.0					
105 min	48.8		144.0					
120 min	51.6		154.0					
135 min	54.0		164.0					
150 min	56.8		173.0					
165 min	59.2		blew out at					
180 min	61.2		160 min.-final vol. 188.0					

* O.S. - Off scale on a Fann VG Meter equipped with a one multiplier spring.

Data Sheet - 20

Sample E Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Top Separation					None		None	
Density, lb/gal	8.7							
Shear Strength, lb/100 sq.ft.			10		10		10	
pH	10.3		8.7		8.5		8.5	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	37	30	11.5	11	16.5	15	12.5	11.5
300 rpm	22	18	6.5	6.5	10	9	7	6.5
200 rpm	17	13.5	4.5	4.5	7.5	8	5	4.5
100 rpm	10	8	3.0	2.5	4.5	4	3	3
6 rpm	2.0	1.5	0.5	0.5	.5	.5	.5	.5
3 rpm	1.5	1.0	0.5	0.5	.5	.5	.5	0
Plastic Viscosity, cp	15	12	5	4.5	6.5	6	5.5	5
Yield Point, lb/100 sq.ft	7.0	6	1.5	2	3.5	3	1.5	1.5
10-sec Gel lb/100 sq.ft.	2.0	2	1	1	.5	.5	.5	0
10-min Gel lb/100 sq.ft.	4.0	3	1	1	3	3	1	1
API Filtrate, ml	8.9		12.3		13.7		15.2	
HTHP Filtrate (30 min), ml	34.0		61.2		74.8		65.2	
HTHP Filtrate at various time increments								
1 min	7.0		13.6		12.4		12.8	
3 min	11.6		22.4		22.4		20.2	
7.5 min	17.0		32.0		36.0		34.4	
15 min	24.4		44.4		52.0		46.8	
30 min	34.0		61.2		74.8		65.2	
45 min	41.6		73.2		90.4		78.8	
60 min	48.2		82.8		104.6		90.0	
75 min	54.8		91.2		117.2		100.4	
90 min	60.2		98.4		127.4		109.2	
105 min	64.6		105.6		137.6		116.6	
120 min	69.6		112.4		146.8		124.4	
135 min	73.8		118.4		156.0		131.6	
150 min	78.2		124.0		164.6		138.8	
165 min	82.4		128.8		172.0		145.2	
180 min.	85.4		134.0		180.0		151.0	

Data Sheet - 21

Sample F Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
					None		None	
Top Separation								
Density, lb/gal (Top)			13.7		17.5		15.5	
(Bottom)			18.3		20.3		19.7	
Shear Strength, lb/100 sq. ft.			850		1800		650	
pH	9.5		8.8		8.7		8.7	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	98	77	89	81	97	81	115	99
300 rpm	50	39.5	52	42	62	51	93	79
200 rpm	34	27	36.5	31	51	42	84	71
100 rpm	18	14.5	20	17	38	31	73	62.5
6 rpm	2	1.5	2	2	24	21	60	52
3 rpm	1	1	1.5	1	22	15	54	41
Plastic Viscosity, cp	48	37.5	37	39	35	30	22	20
Yield Point, lb/100 sq. ft.	2	2.0	15	3	27	21	71	59
10-sec Gel lb/100 sq. ft.	1.5	1.0	2.5	2.5	25	23	48	41
10-min Gel lb/100 sq. ft.	2	20	17	22	42	40	65	57
API Filtrate, ml	1.2		6.2		22.8		65	
HTHP Filtrate (30 min), ml	8.0		28.8		150.4			
HTHP Filtrate at various time increments								
1 min	1.8		6.0		16.4		16.0	
3 min	3.2		8.4		34.0		30.8	
7.5 min	4.0		12.8		55.4		50.6	
15 min	5.4		18.8		83.4		76.4	
30 min	8.0		28.8		150.4			
45 min	9.8		37.6					
60 min	11.6		42.0					
75 min	13.2		46.0		blew out at			
90 min	14.8		50.8		30 min			
105 min	16.2		54.0					
120 min	17.2		58.0					
135 min	18.2		60.4					
150 min	19.2		63.4					
165 min	20.4		65.6					
180 min	21.4		68.2					

Data Sheet - 22

Sample G Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Top Separation					None		None	
Density, lb/gal (Top)			12.1		9.9*		14.3	
(Bottom)			21.4		18.5		18.5	
Shear Strength, lb/100 sq. ft.			750		250		1200	
pH	9.5		8.3		7.9		7.8	
Test Temperature, °F								
Fann V.G. Meter Readings	125	150	125	150	125	150	125	150
600 rpm	66.5	52.5	75	69	257	253	OS*	OS*
300 rpm	33.5	26.5	52	43	215	220	OS*	OS*
200 rpm	22	16.5	42	34	213	200	OS*	OS*
100 rpm	11.5	9	32	25	174	189	OS*	OS*
6 rpm	1	1	22	18	132	149	205	202
3 rpm	0.5	0.5	18	14	120	134	149	145
Plastic Viscosity, cp	33	26	23	26	42	33	-	-
Yield Point, lb/100 sq. ft.	0.5	.5	29	17	173	187	-	-
10-sec Gel lb/100 sq. ft.	1.5	1	22.5	19.5	128	124	130	125
10-min Gel lb/100 sq. ft.	14	16	32.0	28.5	126	125	132	128
API Filtrate, ml	3.8		24.3		14.8		16.6	
HTHP Filtrate (30 min), ml	26.8		126.8		-		-	
HTHP Filtrate at various time increments								
1 min	8.0		23.2		28.4		34.2	
3 min	11.8		37.6		51.4		61.2	
7.5 min	16.4		58.8		100.0		116.4	
15 min	20.8		86.8					
30 min	26.8		126.9					
45 min	31.8							
60 min	36.4							
75 min	40.4							
90 min	43.2							
105 min	46.2							
120 min	49.6							
135 min	51.8							
150 min	54.0							
165 min	56.6							
180 min	59.6							

Data Sheet - 23

Sample H Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
					None		None	
Top Separation								
Density, lb/gal (Top)			16.5		15.1		15.1	
(Bottom)			18.1		18.4		17.3	
Shear Strength, lb/100 sq.ft.			2600		600		1025	
pH	11.0		8.7		8.8		8.9	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	230	194	153	137	145	126	206	182
300 rpm	136	116.5	104	95	106	96	152	135
200 rpm	101	87	88	78	95	84	138	125
100 rpm	62	54.5	62	57	77	69	116	110
6 rpm	12	12	29	31	54	55	81	81
3 rpm	9	9.5	26	29	52	53	78	78
Plastic Viscosity, cp	94	77.5	49	42	39	30	54	47
Yield Point, lb/100 sq.ft.	42	39	55	53	67	66	98	88
10-sec Gel lb/100 sq.ft.	10.5	10.5	36	32	70	67	89	89
10-min Gel lb/100 sq.ft.	38.5	42.5	112.5	104	159	126	157	157
API Filtrate, ml	1.6		5.5		9.4		9.1	
HTHP Filtrate (30 min), ml	6.8		27.0		41.2		40.6	
HTHP Filtrate at various time increments								
1 min	1.6		3.8		6.2		6.0	
3 min	2.4		7.2		12.4		11.0	
7.5 min	3.4		12.4		20.0		18.4	
15 min	4.8		18.0		28.2		27.6	
30 min	6.8		27.0		41.2		40.6	
45 min	8.4		36.0		50.6		49.6	
60 min	9.6		40.0		59.6		58.6	
75 min	11.2		44.8		68.0		66.6	
90 min	12.2		50.2		74.0		74.6	
105 min	13.2		54.4		80.6		79.6	
120 min	14.4		64.8		87.2		85.8	
135 min	15.2		-		92.4		91.2	
150 min	16.0				98.0		96.8	
165 min	16.8				102.4		101.6	
180 min	17.6				106.2		105.6	

Data Sheet - 24

Sample 1 Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Top Separation (Top)			17.1		18.1		15.4	
Density, lb/gal (Bottom)			17.4		18.5		17.9	
Shear Strength, lb/100 sq.ft.			2000		2500		700	
pH	9.1		8.7		8.1		8.5	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	72	66	OS*	OS*	OS*	OS*	OS*	OS*
300 rpm	40.5	34.5	OS*	OS*	OS*	OS*	287.5	239.5
200 rpm	28.5	24.5	OS*	OS*	OS*	281	262	245
100 rpm	16.5	14	OS*	OS*	299	275	260	239
6 rpm	3.5	2.5	OS*	OS*	224	213	174	170
3 rpm	2	1.5	OS*	OS*	215	208	149	148
Plastic Viscosity, cp	31.5	31.5	-	-	-	-	-	-
Yield Point, lb/100 sq.ft.	9	3.0	-	-	-	-	-	-
10-sec Gel lb/100 sq.ft.	4	3.5	OS*	224	217	192	152	120
10-min Gel lb/100 sq.ft.	6.0	6.0	OS*	OS*	294	268	169	179
API Filtrate, ml	2.4		14.0		21.5		18.2	
HTHP Filtrate (30 min), ml	10.0		64.0		96.6		85.0	
HTHP Filtrate at various time increments								
1 min	4.0		10.8		14.2		12.4	
3 min	4.6		18.8		26.6		23.4	
7.5 min	5.8		30.4		43.8		62.0	
15 min	7.4		44.0		64.0		69.4	
30 min	10.0		64.0		96.6		85.0	
45 min	11.6		80.0		123.4		110.0	
60 min	13.2				145.0		126.0	
75 min	15.2				164.4		146.0	
90 min	16.8				187.4			
105 min	18.0							
120 min	19.0							
135 min	20.0							
150 min	20.8							
165 min	21.6							
180 min	22.8							

Data Sheet - 25

Sample J Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Top Separation					None		None	
Density, lb/gal			16.55		17.2		14.0	
Shear Strength, lb/100 sq. ft.			2650		3600		1350	
pH	10.0		8.7		8.2		8.5	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	91	72	141	124	OS*	OS*	113	109.5
300 rpm	50.5	37	115	90	OS*	OS*	101	95
200 rpm	35.5	26.5	107	86	OS*	OS*	102	92
100 rpm	20	15	89	71	OS*	OS*	95	86
6 rpm	3	25	59	53	172	170.5	77	69
3 rpm	2	1.51	52	47	150	153.5	62	57.5
Plastic Viscosity, cp	40.5	35	26	34	-	-	12	14.5
Yield Point, lb/100 sq. ft.	10	2	89	56	-	-	89	80.5
10-sec Gel lb/100 sq. ft.	3	3	46	39	129	133.5	50	47
10-min Gel lb/100 sq. ft.	5	5	65	56	130	118	71	62.5
API Filtrate, ml	0.9		8.5		23.1**		23.7*	
HTHP Filtrate (30 min), ml	5.6		62.2		60.8		124.2	
HTHP Filtrate at various time increments								
1 min	1.0		9.8		10.0		17.6	
3 min	2.0		18.0		20.0		35.2	
7.5 min	2.8		28.4		37.6		56.2	
15 min	3.6		42.4		59.0		84.4	
30 min	5.6		62.2		88.8		124.2	
45 min	7.2		78.0		114.8		155.2	
60 min	8.8		90.00					
75 min	10.0		104.8					
90 min	11.2		116.0					
105 min	12.2							
120 min	13.2							
135 min	14.0							
150 min	15.2							
165 min	16.0							
180 min	17.0							

*O.S. - Off scale on a Fann VG Meter equipped with a one multiplier spring.

Data Sheet - 26

Sample K Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi	
Oil Separation, % by vol.			None		None		None	
Settling:								
Density: Top			16.2		17.1		15.3	
Bottom			17.4		17.4		17.2	
Shear Strength lb/100 sq.ft.			2767		3000		1500	
Electrical								
Stability, Volts	1172		1230		540		580	
Test Temperature, °F	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings								
600 rpm	245	150	268	213	OS*	OS*	OS*	OS*
300 rpm	139	90	144	119	219	187	222	182
200 rpm	102.5	68.5	106	84	160	136	170	135
100 rpm	73	44	59	48	92	79.5	101	84
6 rpm	17	14	8	7.5	13	13	22	22
3 rpm	14	12	6	5.5	9.5	9.5	18	18
Plastic Viscosity, cp	106	60	124	94	-	-	-	-
Yield Point, lb/100 sq.ft.	33	30	20	25	-	-	-	-
10-sec Gel lb/100 sq.ft.	19	16	9	10	14.5	14.5	28	28
10-min Gel lb/100 sq.ft.	23.5	20	34	35	36	37	48	43
API Filtrate, ml	0				16.7		16.8	
HTHP Filtrate (30 min), ml	0.4		104.0		-		114.8	
HTHP Filtrate at various time increments								
1 min	0.0		20.0		19.0		20.4	
3 min	0.0		29.0		34.0		34.0	
7.5 min	0.0		48.0		57.2		54.0	
15 min	0.2		69.0		97.2		78.0	
30 min	0.4		104.0				114.8	
45 min	0.8		129.0				142.8	
60 min	1.0		153.0				168.4	
75 min	1.6						190.4	
90 min	2.0							
105 min	2.4							
120 min	2.8							
135 min	3.2							
150 min	3.4							
165 min	3.6							
180 min	3.8							

Data Sheet - 27

Sample L Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi		550°F/ 500 psi	
Oil Separation, % by vol			None		None		None		None	
Settling:										
Density: Top			12.3		11.9		15.2		13.6	
Bottom			22.4		21.4		20.4		21.7	
Shear Strength, lb/100 sq.ft.			180		550		240		550	
Electrical Stability, Volts	800		1044		900		1070		1030/1016	
Test Temperature, °F										
Fann V.G. Meter Readings	125	150	125	150	125	150	125	150	125	150
600 rpm	216	153	263.5	220	238	181	05*	233	218	192
300 rpm	118	84.5	150.5	125	131	97	176	136	123	109
200 rpm	83	60	109	90	92.5	68	129	99	88	79
100 rpm	45	33.5	63.5	52.5	51	38	78	59	52.5	47
6 rpm	5	4	11.0	9	6	4	14	10	12	11
3 rpm	3	3	8.5	6	4	3	11	8	10	9
Plastic Viscosity, cp	98	68.5	1130	95	107	84	-	97	95	83
Yield Point, lb/100 sq.ft.	20	16	37.5	30	24	13	-	39	28	26
10-sec Gel lb/100 sq.ft.	7.5	7	12.5	11	6	4	16	10	17	16
10-min Gel lb/100 sq.ft.	24	24	51	44	29	22	66	51	54	47
API Filtrate, ml	0		0		0		0		0	
HTHP Filtrate (30 min), ml	0.2		0.6		6.0		0.8		1.6	
HTHP Filtrate at various time increments										
1 min	0.0		0.0		0.8		0.0		0.0	
3 min	0.0		0.0		2.2		0.0		0.4	
7.5 min	0.0		0.0		3.4		0.0		0.8	
15 min	0.0		0.0		4.4		0.0		1.0	
30 min	0.2		0.6		6.0		0.8		1.6	
45 min	0.6		0.8		7.6		1.0		2.0	
60 min	0.8		1.0		8.0		1.2		2.4	
75 min	1.0		1.2		8.8		1.6		2.6	
90 min	1.2		1.8		9.6		1.8		3.0	
105 min	1.4		2.2		10.8		2.0		3.6	
120 min	1.6		2.8		11.6		2.2		3.8	
135 min	1.8		3.4		12.0		2.4		4.0	
150 min	2.0		4.0		12.4		2.6		4.4	
165 min	2.0		4.6		13.2		2.8		5.0	
180 min	2.2		5.2		14.4		3.0		5.2	

Data Sheet - 28

Sample M Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi		550°F/ 500 psi	
			None		None		None		None	
Oil Separation, % by vol.										
Settling:										
Density: Top			17.1		18.0		17.6		17.7	
Bottom			17.4		17.6		17.7		17.8	
Shear Strength, lb/100 sq.ft			>3900		3400		1600		3000	
Electrical Stability, Volts	1080		122		620		500		200/580	
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	270	171	OS*	OS*	OS*	224	287	217	OS*	288
300 rpm	154	95.5	202	171	165	120	153	117	186	133
200 rpm	112	68	142	120	115	83	107	82	131	95
100 rpm	63.5	39	79	67.5	62	45	59	46	73	54
6 rpm	9	6	9	8.5	7	5.5	7.5	6.5	9	7
3 rpm	7.5	4	6	6	4	3.5	4.5	4.5	6	5
Plastic Viscosity, cp	116	75.5	-	-	-	104	134	100	-	105
Yield Point, lb/100 sq.ft	38	20	-	-	-	16	19	17	-	28
10-sec Gel lb/100 sq.ft.	8.5	6	7	6	5	6	4	5	7	6
10-min Gel lb/100 sq.ft.	20	13	14	14	10	10	14	10	15	14
API Filtrate, ml	0				0		0		0.0	
HTHP Filtrate (30 min), ml	0.8		0.2		1.0		2.4		2.2	
HTHP Filtrate at various time increments										
1 min	0.0		0.0		0.0		0.2		0.0	
3 min	0.0		0.0		0.0		0.6		0.0	
7.5 min	0.2		0.0		0.0		1.0		1.0	
15 min	0.4		0.0		0.4		1.6		1.6	
30 min	0.8		0.2		1.0		2.4		2.2	
45 min	1.2		0.2		1.8		3.0		2.6	
60 min	1.2		0.8		2.2		3.8		3.0	
75 min	1.8		1.2		2.4		4.0		3.2	
90 min	2.2		1.6		2.8		4.4		3.6	
105 min	2.4		1.8		3.2		4.8		4.0	
120 min	2.4		2.0		3.6		5.2		4.4	
135 min	2.8		2.2		3.8		5.4		4.6	
150 min	3.2		2.4		4.0		5.6		4.8	
165 min	3.4		2.4		4.4		6.0		5.2	
180 min	3.6		2.6		4.8		6.4		5.6	

* O.S. - Off scale on Fann VG Meter equipped with a one multiplier spring.

Data Sheet - 29

Sample N Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud	450°F/ 300 psi	500°F/ 15,000 psi	500°F/ 375 psi	550°F/ 500 psi
		10ml	None	8.6	6.8
Oil Separation, % by vol.					
Settling:		10.5	9.9	13.6	14.8
Density: Top		21.6	21.5	22.2	20.6
Bottom					
Shear Strength, lb/100 sq.ft.		500	170	120	300
Electrical Stability, Volts	1350	1548	1980/910	1860/1056	1568/640
Test Temperature, °F	125 150	125 150	125 150	125 150	125 150
Fann V.G. Meter Readings					
600 rpm	185 145	157 135	OS* 294	OS* OS*	180 138
300 rpm	106 83	84 72	21.4 180	181 157	94.5 73
200 rpm	77 62	58.5 50.5	149 132	134 113	65 50
100 rpm	47 38.5	32.5 28.5	88 78	78 66	34.5 27.5
6 rpm	11 10	5 4.5	9.5 8.5	8 7	4.5 4
3 rpm	9 8	3.5 3	5 5	4.5 4.5	3 3
Plastic Viscosity, cp	79 62	72 63	- 114	- -	85.5 65
Yield Point, lb/100 sq.ft.	27 21	12 9	- 66	- -	9 8
10-sec Gel lb/100 sq.ft.	11 10	6 5	6.5 6	6 5.5	5 5.5
10-min Gel lb/100 sq.ft.	5 14	12 12	17 16	16.5 16	13 14
API Filtrate, ml	0		20	6.0	1.3
HTHP Filtrate (30 min), ml	0.4	5.2	70.0	11.0	45.6
HTHP Filtrate at various time increments					
1 min	0.0	2.0	14.0	8.0	19.2
3 min	0.0	2.4	27.6	10.0	31.2
7.5 min	0.0	3.2	44.0	10.0	40.0
15 min	0.2	4.0	60.0	10.2	43.2
30 min	0.4	5.2	70.0	11.0	45.6
45 min	1.0	7.2	74.0	11.8	46.8
60 min	1.2	16.4	76.4	13.0	52.4
75 min	1.6	17.2	79.6	14.8	72
90 min	1.8	17.8	84.0	19.4	104
105 min	2.2	18.4	94.0	23.8	135.0
120 min	2.6	20.4	107.6	26.0	
135 min	2.8	22.4	118.0	27.4	
150 min	3.0	26.0	126.4	28.2	
165 min	3.2	30.2	128.4	29.4	
180 min	3.4	32.6	129.6	30.8	

*O.S. - Off scale on a Fann VG Meter equipped with a one multiplier spring.

Data Sheet - 30

Sample 0 Static aged - 24 Hours - at Various Temperature & Pressure

Static Aging Conditions (°F, Pressure)	Original Mud		450°F/ 300 psi		500°F/ 15,000 psi		500°F/ 375 psi		550°F/ 500 psi	
			8.6		1.4		None		None	
Oil Separation, % by vol										
Settling:			13.45		13.6		15.8		13.9	
Density: Top			22.5		21.6		22.0		22.9	
Bottom										
Shear Strength, lb/100 sq.ft			725		360		200		>10,000	
Electrical	1520		1500		1920		1960		920/1420	
Stability, Volts										
Test Temperature, °F	125	150	125	150	125	150	125	150	125	150
Fann V.G. Meter Readings										
600 rpm	162	129	235	174	263	184	247	191	OS*	273
300 rpm	94	75	142	103	162	113.5	157.5	120	234.5	163.5
200 rpm	68.5	55	107	76	124	86	119	93	173	124
100 rpm	40.5	33	68	48	81.5	56	79	62	112	81
6 rpm	5	4.5	19	14	26	17	27	20	38	29
3 rpm	3	2.5	16	11.5	23	15	24	18	33.5	26
Plastic Viscosity, cp	68	54	93	71	101	70.5	92.5	71	-	109.5
Yield Point, lb/100 sq.ft	26	21	49	32	61	43	62	49	-	54.0
10-sec Gel lb/100 sq.ft.	4.5	4.0	25	18	31	21	30	24	39	31
10-min Gel lb/100 sq.ft.	9.5	9.5	50	42	58	51	60	52	60	53.5
API Filtrate, ml	0				4.4		5.4		7.5	
HTHP Filtrate (30 min), ml	2.4		22.6		19.8		32.0		80.0	
HTHP Filtrate at various time increments										
1 min	0.0		5.0		4.6		5.2		11.2	
3 min	0.2		8.0		8.4		9.4		20.2	
7.5 min	0.4		13.0		12.2		16.4		37.2	
15 min	1.6		17.2		15.8		23.2		51.8	
30 min	2.4		22.6		19.8		32.0		80.0	
45 min	3.0		26.4		22.8		39.6		101.4	
60 min	3.6		29.0		25.6		46.6		118.4	
75 min	4.0		31.6		28.0		49.6			
90 min	4.4		33.4		30.0		53.6			
105 min	4.8		35.0		32.0		56.6			
120 min	5.2		38.2		34.0		59.6			
135 min	5.6		40.8		35.6		61.8			
150 min	6.0		43.0		37.2		64.6			
165 min	6.4		45.2		38.6		66.6			
180 min	6.8		47.4		40.0		69.2			

* O.S. - Off scale on a Fann VG Meter equipped with a one multiplier spring.

APPENDIX C

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Data Sheet - 1

CORROSION TEST - SAMPLE A UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	29179	28802	28803	29042	29173	29164	28968
WEIGHT LOSS, GRAMS	.1283	.1317	.1553	.1326	.0392	.0469	.0500
CORROSION RATE, MILS PER YEAR	168.2	86.3	40.7	21.7	517.1	20.5	21.8
DESCRIPTION OF MILD STEEL COUPON	Generalized	Generalized	Generalized	Generalized	Generalized	Generalized Black Film No FeS	Generalized Black Film No FeS
DESCRIPTION OF PRESTRESSED ROLLER BEARING	Cracked Dark color No FeS	Cracked Dark color No FeS	Cracked Black No FeS	Cracked Light color No FeS	No crack	No crack Black No FeS	No crack Black No FeS

Data Sheet - 2

CORROSION TEST - SAMPLE B - UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi 8 hours	16 hours	40 hours	64 hours	450°F 300 psi	500°F 375 psi	500°F 15,000 psi
COUPON NUMBER	29027	28807	29030	29172	28796	29177	28797
WEIGHT LOSS, GRAMS	.0072	.0160	.0281	.014	.0232	.0448	.2158
CORROSION RATE, MILS PER YEAR	9.4	10.8	4.2	4.6	10.1	19.6	94.3
DESCRIPTION OF MILD STEEL COUPON	Very little discoloring	Very little discoloring	Very little discoloring	Very little discoloring	Generalized with light streaks	Black No FeS	Black No FeS
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Very little discoloring No FeS	No crack Very little discoloring No FeS	No crack Moderate discoloring No FeS	No crack Moderate discoloring No FeS	No crack	No crack No FeS	No crack No FeS

Data Sheet - 3

CORROSION TEST - SAMPLE C UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	29086	29163	29070	29171	29098	29023	29022
WEIGHT LOSS, GRAMS	.014	.0236	.0373	.0385	.0253	.0428	.1623
CORROSION RATE, MILS PER YEAR	18.7	15.5	9.8	6.3	11.1	18.7	70.7
DESCRIPTION OF MILD STEEL COUPON	Generalized	Generalized	Generalized	Generalized	Generalized	Black, FeS present	Black FeS present
DESCRIPTION OF PRESTRESSED ROLLER BEARING	Cracked No FeS Discolored around bands	Cracked No FeS Discolored around bands	No crack No FeS Discolored around bands	Cracked No FeS Discolored around bands	No crack	Black, FeS present	Black, FeS present

Data Sheet - 4

CORROSION TEST - SAMPLE D UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	29175	29014	29011	28819	29091	29016	29017
WEIGHT LOSS, GRAMS	.2475	.3716	.3318	.3580	.0198	.0902	.1294
CORROSION RATE, MILS PER YEAR	359.9	243.6	87.0	58.7	8.6	39.4	56.5
DESCRIPTION OF MILD STEEL COUPON	Dark film which came off easily	Dark film which came off easily	Dark film which came off easily	Dark film which came off easily	Generalized	Generalized Dark film	Generalized Dark film
DESCRIPTION OF PRESTRESSED ROLLER BEARING	Cracked, Discolored No FeS	Cracked, FeS in crack	Cracked, FeS in crack	Cracked, FeS in crack	No crack	No crack, Grey color FeS was present	No crack Grey color FeS was present

CORROSION TEST - SAMPLE E UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	28826	29028	29012	29032	29095	29040	28809
WEIGHT LOSS, GRAMS	.0608	.0582	.0871	1019	.0112	.0073	.0086
CORROSION RATE, MILS PER YEAR	79.7	38.2	22.8	16.7	4.9	3.2	3.8
DESCRIPTION OF MILD STEEL COUPON	Dark discolor- ation	Dark discolor- ation	Dark discolor- ation	Dark discolor- ation	Generalized	Black	Black
DESCRIPTION OF PRESTRESSED ROLLER BEARING	Cracked Bluish color No FeS	No crack No FeS	Cracked No FeS	Cracked No FeS	No crack	Cracked Thin shiny bands No FeS	No crack Thin shiny bands No FeS

Data Sheet - 6

CORROSION TEST - SAMPLE F UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	29013	28822	29039	29096	29068	29093	29157
WEIGHT LOSS, GRAMS	.0061	.0229	.0257	.0376	.0404	.0501	.0693
CORROSION RATE, MILS PER YEAR	8.0	15.0	6.7	6.2	17.6	21.9	29.8
DESCRIPTION OF MILD STEEL COUPON	Clear very light film	Light grey with darker speckled patterns	Generalized Grey	Generalized Grey	Generalized	FeS present	FeS present
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No Crack Shiny No FeS	Cracked Some discoloring No FeS	Cracked Black and grey No FeS	Cracked Black and grey No FeS	Cracked No FeS	Cracked Shiny under bands FeS traces	Cracked Discolored No FeS

CORROSION TEST - SAMPLE G UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	29097	29178	28808	29156	28840	28804	28838
WEIGHT LOSS, GRAMS	.0669	.0789	.1192	.1154	.0478	.0510	.0604
CORROSION RATE, MILS PER YEAR	87.7	51.7	31.2	18.9	20.9	22.3	26.4
DESCRIPTION OF MILD STEEL COUPON	Discolored Sticky material hardened on coupon, Pitted	Discolored Sticky material hardened on coupon Pitted	Discolored Sticky material hardened on coupon Pitted	Discolored Sticky material hardened on coupon Pitted	Generalized	Generalized	Generalized
DESCRIPTION OF PRESTRESSED ROLLER BEARING	Cracked Black film on bearing No FeS	Cracked Shiny with dark bands	Cracked Black	Cracked Black	Cracked No FeS	No crack Discolored No FeS	No crack Discolored No FeS

Data Sheet - 8

CORROSION TEST - SAMPLE H UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	28833	28823	29043	28839	28969	28817	29092
WEIGHT LOSS, GRAMS	.0152	.0218	.0217	.0172	.0362	.0212	.0278
CORROSION RATE, MILS PER YEAR	19.9	14.3	5.7	2.8	15.8	9.3	12.1
DESCRIPTION OF MILD STEEL COUPON	Generalized Grey	Generalized Grey Had one black spot	Generalized Grey	Generalized Grey	Generalized	Trace of FeS	Trace of FeS
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Shiny No FeS	No crack Shiny No FeS	No crack Tarnished No FeS	No crack Black No FeS	No crack No FeS	No crack Dark with bands FeS present	No crack Dark with bands FeS present

Data Sheet - 9

CORROSION TEST - SAMPLE 1 UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	29103	29166	29176	29024	29026	28824	28806
WEIGHT LOSS, GRAMS	.0098	.0177	.0274	.0351	.0449	.0431	.0416
CORROSION RATE, MILS PER YEAR	12.8	11.6	7.2	5.8	19.6	18.8	18.2
DESCRIPTION OF MILD STEEL COUPON	Generalized Grey No FeS	Generalized Grey with black spots No FeS	Generalized Grey with black spots No FeS	Generalized Grey No FeS	Generalized	Generalized	Generalized
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Black under rings No FeS	Cracked Black under rings No FeS	No crack No FeS Bands and other discolored areas	Cracked Bands No FeS	No crack No FeS	No crack Dark film Shiny under bands No FeS	No crack Black-blue film Shiny under bands No FeS

Data Sheet - 10

CORROSION TEST - SAMPLE J UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	28841	28813	29010	28854	28818	29101	28992
WEIGHT LOSS, GRAMS	.0066	.0306	.0222	.0339	.0291	.0459	.0385
CORROSION RATE, MILS PER YEAR	8.6	20.1	5.8	5.6	12.7	20.1	16.8
DESCRIPTION OF MILD STEEL COUPON	Light grey No FeS	Light grey One black spot No FeS	Grey One spot No FeS	Grey No FeS	Generalized	Generalized	Generalized
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Shiny No FeS	No crack Shiny Some black spots No FeS	No crack No FeS	No crack Light grey with some shiny spots No FeS	No crack No FeS	No crack No FeS	No crack No FeS

CORROSION TEST - SAMPLE J UNDER DYNAMIC AND STATIC TEST CONDITIONS

Data Sheet - 11

CORROSION TEST - SAMPLE K UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS		
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi
	8 hours	16 hours	40 hours	64 hours			
COUPON NUMBER	29094	29033	29034	29035	29160	29161	28810
WEIGHT LOSS, GRAMS	.0732	.1447	.3376	.5781	.1038	.1153	.1231
CORROSION RATE, MILS PER YEAR	96.0	94.8	88.5	94.7	45.4	50.4	53.8
DESCRIPTION OF MILD STEEL COUPON	Light grey No FeS	Light grey No FeS	Light grey No FeS	Light grey No FeS	Generalized	Black No FeS	Black FeS present
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Light grey no banding No FeS	Cracked Grey with black areas No FeS	No crack Black with banding No FeS	Cracked Black with no banding No FeS	No crack Black outside film Two distinct bands	No crack Black banded No FeS	No crack Black banded No FeS

Data Sheet - 12

CORROSION TEST - SAMPLE L UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS			
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi	550°F 500 psi
	8 hours	16 hours	40 hours	64 hours				
COUPON NUMBER	29087	29038	29037	28827	29021	28831	28834	28812
WEIGHT LOSS, GRAMS	.0082	.0123	.0113	.0109	.0268	.0524	.0435	.0888
CORROSION RATE, MILS PER YEAR	10.8	8.1	3.0	1.8	11.7	22.9	19.0	38.8
DESCRIPTION OF MILD STEEL COUPON	Clean No FeS	Clean No FeS	Clean No FeS	Clean No FeS	Generalized	Slate grey No FeS	Slate grey No FeS	Black No FeS
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Shiny No FeS	No crack Shiny (some black areas) No FeS	No crack Shiny No FeS	No crack Shiny (some black areas) No FeS	No crack Brownish film over entire bearing	No crack Copper colored Slightly banded No FeS	No crack Copper colored Slightly banded No FeS	No crack Black No bands No FeS

Data Sheet - 13

CORROSION TEST - SAMPLE M UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS			
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi	550°F 500 psi
	8 hours	16 hours	40 hours	64 hours				
COUPON NUMBER	29174	28836	28837	29167	29152	29162	28800	29159
WEIGHT LOSS, GRAMS	.0054	.0161	.0059	.0244	.0404	.0310	.0325	.0409
CORROSION RATE, MILS PER YEAR	7.1	10.6	1.5	4.0	17.6	13.5	14.2	17.9
DESCRIPTION OF MILD STEEL COUPON	Clean No FeS	Clean No FeS	Clean No FeS	Clean No FeS	Generalized	Black No FeS	Black No FeS	Black No FeS
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Shiny No FeS	No crack Shiny No FeS	No crack Shiny No FeS	No crack Shiny No FeS	No crack Blue film Shiny after detecting solution applied No FeS	No crack No bands Shiny after detecting solution applied No FeS	No crack No bands Shiny after detecting solution applied No FeS	No crack Copper colored No bands No FeS

Data Sheet - 14

CORROSION TEST -- SAMPLE N UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS			
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi	550°F 500 psi
	8 hours	16 hours	40 hours	64 hours				
COUPON NUMBER	28835	28970	29170	29006	29158	29168	29007	28863
WEIGHT LOSS, GRAMS	.0423	.0638	.1093	.1559	.0734	.1030	.0729	.1253
CORROSION RATE, MILS PER YEAR	55.4	41.8	28.7	25.5	32.1	45.0	31.9	54.8
DESCRIPTION OF MILD STEEL COUPON	Light grey No FeS	Generally dark grey Little FeS	Generally dark grey Some FeS	Generally dark grey Some FeS		Black FeS present	Black FeS present	Black No FeS
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Light grey Some banding No FeS	No crack Generally dark Little FeS	No crack Light, dark under bands Little FeS	No crack Dark Shiny under bands Little FeS	No crack Blue film FeS present	Cracked Dark blue film FeS present	No crack Dark blue film No FeS	No crack Light black film No bands No FeS

Data Sheet - 15

CORROSION TEST - SAMPLE 0 UNDER DYNAMIC AND STATIC TEST CONDITIONS

AGING CONDITIONS	DYNAMIC TESTS				STATIC TESTS			
	Rolled at 350°F, 300 psi				450°F 300 psi	500°F 375 psi	500°F 15,000 psi	550°F 500 psi
	8 hours	16 hours	40 hours	64 hours				
COUPON NUMBER	28830	28798	29005	28801		28832	29154	29089
WEIGHT LOSS, GRAMS	.0124	.0170	.0193	.0160	.0155	.0233	.0283	.0350
CORROSION RATE, MILS PER YEAR	16.3	11.1	5.1	2.6	6.8	10.2	12.4	15.3
DESCRIPTION OF MILD STEEL COUPON	Light grey No FeS	Grey No FeS	Grey No FeS	Grey No FeS	Generalized	Black No FeS	Black No FeS	Black No FeS
DESCRIPTION OF PRESTRESSED ROLLER BEARING	No crack Clean and shiny No FeS	No crack Clean and shiny No FeS	No crack Clean and shiny No FeS	No crack Clean and shiny No FeS	No crack Blue film Shiny after detecting solution applied No FeS	No crack Blue-gold film No FeS	No crack Blue-gold film No FeS	No crack Purple- blue film No bands No FeS

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