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(57) **Abrégé/Abstract:**

A method for drilling, running casing, in, and/or cementing a borehole in a subterranean formation without significant loss of drilling fluid is disclosed, as well as compositions for use in such method. The method employs a drilling fluid comprising a fragile gel or having fragile gel behavior and providing superior oil mud rheology and overall performance. The fluid is especially advantageous for use in deep water wells because the fluid exhibits minimal difference between downhole equivalent circulating density and surface density notwithstanding differences in drilling or penetration rates. When an ester and isomerized olefin blend is used for the base of the fluid, the fluid makes an environmentally acceptable and regulatory compliant invert emulsion drilling fluid. The fluid preferably contains no organophilic clays.

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(54) Title: METHOD OF FORMULATING AND USING A DRILLING MUD WITH FRAGILE GELS

(57) Abstract: A method for drilling, running casing, in, and/or cementing a brothel in a subterranean formation without significant loss of drilling fluid is disclosed, as well as compositions for use in such method. The method employs a drilling fluid comprising a fragile gel or having fragile gel behavior and providing superior oil mud rheology and overall performance. The fluid is especially advantageous for use in deep water wells because the fluid exhibits minimal difference between downhole equivalent circulating density and surface density notwithstanding differences in drilling or penetration rates. When an ester and isomerized olefin blend is used for the base of the fluid, the fluid makes an environmentally acceptable and regulatory compliant invert emulsion drilling fluid. The fluid preferably contains no organophilic clays.

WO 2004/000969 A1

METHOD OF FORMULATING AND USING A DRILLING MUD WITH FRAGILE GELS

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention relates to compositions and methods for drilling, cementing and casing boreholes in subterranean formations, particularly hydrocarbon bearing formations. More particularly, the present invention relates to oil or synthetic fluid based drilling fluids and fluids comprising invert emulsions, such as, for example, fluids using esters, which combine high ecological compatibility with good stability and performance properties.

2. Description of Relevant Art

A drilling fluid or mud is a specially designed fluid that is circulated through a wellbore as the wellbore is being drilled to facilitate the drilling operation. The various functions of a drilling fluid include removing drill cuttings from the wellbore, cooling and lubricating the drill bit, aiding in support of the drill pipe and drill bit, and providing a hydrostatic head to maintain the integrity of the wellbore walls and prevent well blowouts. Specific drilling fluid systems are selected to optimize a drilling operation in accordance with the characteristics of a particular geological formation.

Oil or synthetic fluid-based muds are normally used to drill swelling or sloughing shales, salt, gypsum, anhydrite or other evaporite formations, hydrogen sulfide-containing formations, and hot (greater than about 300 degrees Fahrenheit) holes, but may be used in other holes penetrating a subterranean formation as well. Unless indicated otherwise, the terms "oil mud" or "oil-based mud or drilling fluid" shall be understood to include synthetic oils or other synthetic fluids as well as natural or traditional oils, and such oils shall be understood to comprise invert emulsions.

Oil-based muds used in drilling typically comprise: a base oil (or synthetic fluid) comprising the external phase of an invert emulsion; a saline, aqueous solution (typically a solution comprising about 30% calcium chloride) comprising the internal phase of the invert emulsion; emulsifiers at the interface of the internal and external phases; and other agents or additives for suspension, weight or density, oil-wetting, fluid loss or filtration control, and rheology control. Such additives commonly include organophilic clays and

organophilic lignites. See H.C.H. Darley and George R. Gray, Composition and Properties of Drilling and Completion Fluids 66-67, 561-562 (5th ed. 1988). An oil-based or invert emulsion-based drilling fluid may commonly comprise between about 50:50 to about 95:5 by volume oil phase to water phase. An all oil mud simply comprises 100% oil by volume; that is, there is no aqueous internal phase.

Invert emulsion-based muds or drilling fluids comprise a key segment of the drilling fluids industry. However, increasingly invert emulsion-based drilling fluids have been subjected to greater environmental restrictions and performance and cost demands. There is consequently an increasing need and industry-wide interest in new drilling fluids that provide improved performance while still affording environmental acceptance.

SUMMARY OF THE INVENTION

The present invention provides a fluid and a method for drilling boreholes or wellbores in subterranean formations with reduced loss of drilling fluids or muds into the formation. This advantage of the invention is effected by formulating, providing or using a drilling fluid that forms a "fragile gel." A "gel" may be defined a number of ways. One definition indicates that a "gel" is a generally colloidal suspension or a mixture of microscopic water particles (and any hydrophilic additives) approximately uniformly dispersed through the oil (and any hydrophobic additives), such that the fluid or gel has a generally homogeneous gelatinous consistency. Another definition states that a "gel" is a colloid in a more solid form than a "sol" and defines a "sol" as a fluid colloidal system, especially one in which the continuous phase is a liquid. Still another definition provides that a "gel" is a colloid in which the disperse phase has combined with the continuous phase to produce a viscous jelly-like product. A gel has a structure that is continually building. If the yield stress of a fluid increases over time, the fluid has gels. Yield stress is the stress required to be exerted to initiate deformation.

A "fragile gel" as used herein is a "gel" that is easily disrupted or thinned, and that liquifies or becomes less gel-like and more liquid-like under stress, such as caused by moving the fluid, but which quickly returns to a gel when the movement or other stress is alleviated or removed, such as when circulation of the fluid is stopped, as for example when drilling is stopped. The "fragileness" of the "fragile gels" of the present invention contributes to

the unique and surprising behavior and advantages of the present invention. The gels are so “fragile” that it is believed that they may be disrupted by a mere pressure wave or a compression wave during drilling. They seem to break instantaneously when disturbed, reversing from a gel back into a liquid form with minimum pressure, force and time and with less pressure, force and time than known to be required to convert prior art fluids from a gel-like state into a flowable state.

When drilling is stopped while using a drilling fluid of the present invention, and consequently the stresses or forces associated with drilling are substantially reduced or removed, the drilling fluid forms a gel structure that allows it to suspend drill cuttings and weighting materials for delivery to the well surface. The drilling fluid of the invention suspends drill cuttings through its gel or gel-like characteristics, without need for organophilic clays to add viscosity to the fluid. As a result, sag problems do not occur. Nevertheless, when drilling is resumed, the fragile gel is so easily and instantly converted back into a liquid or flowable state that no initial appreciable or noticeable pressure spike is observed with pressure-while-drilling (PWD) equipment or instruments. In contrast, such pressure spikes are commonly or normally seen when using prior art fluids.

[0010] Further, the drilling fluid of the invention generally maintains consistently low values for the difference in its surface density and its equivalent density downhole during drilling operations notwithstanding variations in the rate of drilling or penetration into the subterranean formation and notwithstanding other downhole stresses on the fluid. The fragile gels of the invention may be visco-elastic, contributing to their unique behavior and to the advantages of the invention.

The drilling fluid of the invention responds quickly to the addition of thinners, with thinning of the fluid occurring soon after the thinners are added, without need for multiple circulations of the fluid with the thinners additive or additives in the wellbore to show the effect of the addition of the thinners. The drilling fluid of the invention also yields flatter profiles between cold water and downhole rheologies, making the fluid advantageous for use in deep water wells. That is, the fluid may be thinned at cold temperatures without causing the fluid to be comparably thinned at higher temperatures. As used herein, the terms “deep water” with respect to wells and “higher” and “lower” with respect to temperature are

relative terms understood by one skilled in the art of the oil and gas industry. However, generally, as used herein, "deep water wells" refers to any wells at water depths greater than about 1500 feet deep, "higher temperatures" means temperatures over about 120 degrees Fahrenheit and "lower temperatures" means temperatures at about 40 to about 60 degrees Fahrenheit. Rheology of a drilling fluid is typically measured at about 120 or about 150 degrees Fahrenheit.

A method for preparing and using a drilling fluid of the invention is also provided by the invention. In the method, an invert emulsion drilling fluid is obtained or prepared that forms fragile gels or that has fragile gel behavior, preferably without the addition of organophilic clays or organophilic lignites, and that has as its base an invert emulsion composition. An example of a suitable base is a blend of esters with isomerized, or internal, olefins ("the ester blend") as described in U.S. Patent Application Publication No. 2003/003648A, of Jeff Kirsner (co-inventor of the present invention), Kenneth W. Pober and Robert W. Pike, filed August 14, 2001, entitled "Blends of Esters with Isomerized Olefins and Other Hydrocarbons as Base Oils for Invert Emulsion Oil Muds.

Drilling fluids of the present invention prepared with such ester blends provide an invert emulsion drilling fluid having significant benefits in terms of environmental acceptance or regulatory compliance while also improving oil mud rheology and overall oil mud performance. The esters in the blend may be any quantity, but preferably should comprise at least about 10 weight percent to about 99 weight percent of the blend and the olefins should preferably comprise about 1 weight percent to about 99 weight percent of the blend. The esters of the blend are preferably comprised of fatty acids and alcohols and most preferably about C₆ to about C₁₄ fatty acids and 2-ethyl hexanol. Esters made other ways than with fatty acids and alcohols, such as for example, esters made from olefins combined with either fatty acids or alcohols, are also believed effective.

Further, the invert emulsion drilling fluid has added to or mixed with it other fluids or materials needed to comprise a complete drilling fluid. Such materials may include thinners or rheology control additives for example. However, preferably no organophilic clays are added to the drilling fluid for use in the invention. Characterization of the drilling

fluid herein as "clayless" shall be understood to mean lacking organophilic clays. Although omission of organophilic clays is a radical departure from traditional teachings respecting preparation of drilling fluids, this omission of organophilic clays in the present invention allows the drilling fluid to have greater tolerance to drill solids (i.e., the properties of the fluid are not readily altered by the drill solids or cuttings) and is believed (without desiring to be limited by theory) to contribute to the fluid's superior properties in use as a drilling fluid.

In accordance with an aspect of the present invention, there is provided a method of drilling in a subterranean formation comprising the steps of: providing an invert emulsion drilling fluid having substantially equal dial readings at 40°F (4.4°C) and at 120°F (48.9°C) when measured at 3 rpm or 6 rpm using a FANN viscometer at atmospheric pressure; and drilling in the subterranean formation with the drilling fluid.

BRIEF DESCRIPTION OF THE DRAWINGS

Figures 1(a), 1(b) and 1(c) provide three graphs showing field data comparing mud losses incurred during drilling, running casing and cementing with a prior art isomerized olefin fluid and with a fluid of the present invention. Figure 1(a) shows the total downhole losses; Figure 1(b) shows the barrels lost per barrel of hole drilled; and Figure 1(c) shows the barrels lost per foot.

Figure 2 is a graph comparing mud loss incurred running casing and cementing in seven boreholes at various depths, where the mud used in the first three holes was a prior art isomerized olefin fluid and the mud used in the last four holes was a fluid of the present invention.

Figure 3 is a graph indicating gel formation in fluids of the present invention and their response when disrupted compared to some prior art isomerized olefin fluids.

Figure 4 is a graph comparing the relaxation rates of various prior art drilling fluids and fluids of the present invention.

Figure 5(a) is a graph comparing the differences in well surface density and the equivalent circulating density for a prior art isomerized olefin fluid and for the fluid of the invention in two comparable wells. Figure 5(b) shows the rate of penetration in the wells at the time the density measurements for Figure 5(a) were being taken.

5a

Figure 6 is a graph comparing the differences in well surface density and the equivalent circulating density for a fluid of the invention with a flowrate of 704 to 811 gallons per minute in a 12 1/4 inch borehole drilled from 9,192 ft to 13,510 ft in deep water and including rate of penetration.

Figure 7 is a graph comparing the differences in well surface density and the

equivalent circulating density for a fluid of the invention with a flowrate of 158 to 174 gallons per minute in a 6 ½ inch borehole drilled from 12,306 ft to 13,992 ft and including rate of penetration.

Figure 8 is a graph comparing the differences in well surface density and the equivalent circulating density for a fluid of the invention at varying drilling rates from 4,672 ft to 12,250 ft, and a flowrate of 522 to 586 gallons per minute in a 9 7/8" borehole.

Figure 9(a) is a bar graph comparing the yield point of two densities of a fluid of the invention at standard testing temperatures of 40 and 120 degrees Fahrenheit. Figures 9(b) and (c) are graphs of the Fann instrument dial readings for these same two densities of a fluid of the invention over a range of shear rates at standard testing temperatures of 40 and 120 degrees Fahrenheit.

Figure 10 is a graph comparing the viscosity of various known invert emulsion bases for drilling fluids with the invert emulsion base for a drilling fluid of the present invention.

DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

The present invention has been tested in the field and the field data demonstrates the advantageous performance of the fluid composition of the invention and the method of using it. As illustrated in Figures 1(a), (b), (c), and 2, the present invention provides an invert emulsion drilling fluid that may be used in drilling boreholes or wellbores in subterranean formations, and in other drilling operations in such formations (such as in casing and cementing wells), without significant loss of drilling fluid when compared to drilling operations with prior art fluids.

Figures 1(a), (b), and (c) show three graphs comparing the actual fluid loss experienced in drilling 10 wells in the same subterranean formation. In nine of the wells, an isomerized olefin based fluid (in this case, tradename PETROFREE® SF available from Halliburton Energy Services, Inc. in Houston, Texas), viewed as an industry "standard" for full compliance with current environmental regulations, was used. In one well, an ACCOLADE™ system, a fluid having the features or characteristics of the invention and commercially available from Halliburton Energy Services, Inc. in Houston, Texas (and also fully complying with current environmental regulations) was used. The hole drilled with an ACCOLADE™ system was 12.25 inches in diameter. The holes drilled with the

“standard” PETROFREE® SF fluid were about 12 inches in diameter with the exception of two sidetrack holes that were about 8.5 inches in diameter. Figure 1(a) shows the total number of barrels of fluid lost in drilling, running, casing and cementing the holes. Figure 1(b) shows the total number of barrels of fluid lost per barrel of hole drilled. Figure 1(c) shows the total number of barrels of fluid lost per foot of well drilled, cased or cemented. For each of these wells graphed in these Figures 1(a), (b) and (c), the drilling fluid (or mud) lost when using a fluid of the invention was remarkably lower than when using the prior art fluid.

Figure 2 compares the loss of mud with the two drilling fluids in running casing and cementing at different well depths in the same subterranean formation. The prior art isomerized olefin based fluid was used in the first three wells shown on the bar chart and a fluid of the present invention was used in the next four wells shown on the bar chart. Again, the reduction in loss of fluid when using the fluid of the present invention was remarkable.

The significant reduction in mud loss seen with the present invention is believed to be due at least in substantial part to the fragile gel behavior of the fluid of the present invention and to the chemical structure of the fluid that contributes to, causes, or results in that fragile gel behavior. According to the present invention, fluids having fragile gels or fragile gel behavior provide significant reduction in mud loss during drilling (and casing and cementing) operations when compared to mud losses incurred with other drilling fluids that do not have fragile gel behavior. Without wishing to be limited by theory, it is believed, for example, that the structure of the drilling fluids of the invention, that is, the fragile gel structure, contributing to the fragile gel behavior results in lower surge and swab pressure while running casing which in turn results in lower mud loss during such casing operations. Thus, according to the method of the invention, drilling fluid loss may be reduced by employing a drilling fluid in drilling operations that is formulated to comprise fragile gels or to exhibit fragile gel behavior. As used herein, the term “drilling operations” shall mean drilling, running casing and/or cementing unless indicated otherwise.

Figure 3 represents in graphical form data indicating gel formation in samples of two different weight (12.65 and 15.6 ppg) ACCOLADE® fluids of the present invention and two comparably weighted (12.1 and 15.6 ppg) prior art invert emulsion fluids (tradename

PETROFREE® SF) at 120 degrees Fahrenheit. When the fluids are at rest or static (as when drilling has stopped in the wellbore), the curves are flat or relatively flat (see area at about 50-65 minutes elapsed time for example). When shear stress is resumed (as in drilling), the curves move up straight vertically or generally vertically (see area at about 68 to about 80 elapsed minutes for example), with the height of the curve being proportional to the amount of gel formed—the higher the curve the more gel built up. The curves then fall down and level out or begin to level out, with the faster rate at which the horizontal line forms (and the closer the horizontal line approximates true horizontal) indicating the lesser resistance of the fluid to the stress and the lower the pressure required to move the fluid.

Figure 3 indicates superior response and performance by the drilling fluids of the present invention. Not only do the fluids of the present invention build up more gel when at rest, which enables the fluids of the invention to better maintain weight materials and drill cuttings in suspension when at rest—a time prior art fluids are more likely to have difficulty suspending such solid materials—but the fluids of the present invention nevertheless surprisingly provide less resistance to the shear, which will result in lower ECDs as will be discussed further below.

Figure 4 provides data further showing the gel or gel-like behavior of the fluids of the present invention. Figure 4 is a graph of the relaxation rates of various drilling fluids, including fluids of the present invention and prior art isomerized olefin based fluids. In the test, conducted at 120 degrees Fahrenheit, the fluids are exposed to stress and then the stress is removed. The time required for the fluids to relax or to return to their pre-stressed state is recorded. The curves for the fluids of the invention seem to level out over time whereas the prior art fluids continue to decline. The leveling out of the curves are believed to indicate that the fluids are returning to a true gel or gel-like structure.

The significant reduction in mud loss seen with the present invention is also believed to be due in substantial part to the suspected viscoelasticity of the fluid of the present invention. Such viscoelasticity, along with the fragile gel behavior, is believed to enable the fluid of the invention to minimize the difference in its density at the surface and its equivalent circulating density downhole. This difference in a drilling fluid's measured surface density at the well head and the drilling fluid's equivalent circulating density

downhole (as typically measured during drilling by downhole pressure-while-drilling (PWD) equipment) is often called “ECD” in the industry. Low “ECDs”, that is, a minimal difference in surface and downhole equivalent circulating densities, is critical in drilling deep water wells and other wells where the differences in subterranean formation pore pressures and fracture gradients are small.

Table 1 below and Figure 5(a) showing the Table 1 data in graph form illustrate the consistently stable and relatively minimal difference in equivalent circulating density and actual mud weight or well surface density for the fluids of the invention. This minimal difference is further illustrated in Figure 5(a) and in Table 1 by showing the equivalent circulating density downhole for a commercially available isomerized olefin drilling fluid in comparison to the drilling fluid of the present invention. Both fluids had the same well surface density. The difference in equivalent circulating density and well surface density for the prior art fluid however was consistently greater than such difference for the fluid of the invention. Figure 5(b) provides the rates of penetration or drilling rates at the time the measurements graphed in Figure 5(a) were made. Figure 5(b) indicates that the fluid of the invention provided its superior performance—low ECDs—at surprisingly faster drilling rates, making its performance even more impressive, as faster drilling rates tend to increase ECDs with prior art fluids.

TABLE 1

Comparison of Equivalent Circulating Densities

DEPTH (in feet)	PWD Data <i>ACCOLADE™</i> <i>System</i> pump rate: 934gpm BIT: 12.25” (ppg)	Mud Weight <i>At well surface</i> (ppg)	PWD Data <i>Isomerized Olefin</i> <i>based fluid</i> pump rate: 936 gpm BIT: 12.25” (ppg)
10600	12.29	12.0	12.51
10704	12.37	12.0	12.53
10798	12.52	12.0	12.72

10,899	12.50	12.2	12.70
11,001	12.50	12.2	12.64
11,105	12.52	12.2	12.70
11,200	12.50	12.2	12.69
11,301	12.55	12.2	12.70
11,400	12.55	12.2	12.71
11,500	12.59	12.2	12.77
11,604	12.59	12.2	12.79
11,700	12.57	12.2	12.79
11,802	12.60	12.2	12.79
11,902	12.62	12.2	12.81
12,000	12.64	12.2	12.83
12,101	12.77	12.2	12.99
12,200	12.77	12.3	12.99
12,301	12.76	12.3	13.01

Figure 6 graphs the equivalent circulating density of an ACCOLADE™ system, as measured downhole during drilling of a 12 ¼ inch borehole from 9,192 feet to 13,510 feet in deepwater (4,900 feet), pumping at 704 to 811 gallons per minute, and compares it to the fluid's surface density. Rate of penetration ("ROP")(or drilling rate) is also shown. This data further shows the consistently low and stable ECDs for the fluid, notwithstanding differences in the drilling rate and consequently the differences in stresses on the fluid.

Figure 7 similarly graphs the equivalent circulating density of an ACCOLADE™ system, as measured downhole during drilling of a 6 ½ inch borehole from 12,306 feet to 13,992 feet, pumping at 158 to 174 gallons per minute in deepwater, and compares it to the fluid's surface density. Rate of penetration (or drilling rate) is also shown. Despite the relatively erratic drilling rate for this well, the ECDs for the drilling fluid were minimal, consistent, and stable. Comparing Figure 7 to Figure 6 shows that despite the narrower

borehole in Figure 6 (6 ½ inches compared to the 12 ¼ inch borehole for which data is shown in Figure 6), which would provide greater stress on the fluid, the fluid performance is effectively the same.

Figure 8 graphs the equivalent circulating density of an ACCOLADE™ system, as measured -downhole during drilling of a 9 7/8 inch borehole from 4,672 feet to 12,250 feet in deepwater, pumping at 522 to 585 gallons per minute, and compares it to the surface density of the fluid and the rate of penetration (“ROP”) (or drilling rate). The drilling fluid provided low, consistent ECDs even at the higher drilling rates.

The present invention also provides a drilling fluid with a relatively flat rheological profile. Table 2 provides example rheological data for a drilling fluid of the invention comprising 14.6 pounds per gallon (“ppg”) of an ACCOLADE™ system.

TABLE 2

ACCOLADE™ System Downhole Properties
FANN 75 Rheology
14.6 lb/gal ACCOLADE™ System

Temp. (° F)	120	40	40	40	80	210	230	250	270
Pressure	0	0	3400	6400	8350	15467	16466	17541	18588
600 rpm	67	171	265	325	202	106	98	89	82
300 rpm	39	90	148	185	114	63	58	52	48
200 rpm	30	64	107	133	80	49	45	40	37
100 rpm	19	39	64	78	47	32	30	27	25
6 rpm	6	6	10	11	11	8	9	8	8
3 rpm	5	6	10	11	11	8	9	8	8
Plastic Viscosity (cP)	28	81	117	140	88	43	40	37	34
Yield Point (lb/100 ft ²)	11	9	31	45	26	20	18	15	14
N	0.837	0.948	0.869	0.845	0.906	0.799	0.822	0.855	0.854

K	0.198	0.245	0.656	0.945	0.383	0.407	0.317	0.226	0.21
Tau 0 (lb/100 ft ²)	4.68	6.07	8.29	8.12	9.68	7.45	8.21	8.29	7.75

Figures 9(b) and (c) compare the effect of temperature on pressures observed with two different fluid weights (12.1 and 12.4 ppg) when applying six different and increasing shear rates (2, 6, 100, 200, 300, and 600 rpm). Two common testing temperatures were used—40 and 120 degrees Fahrenheit. The change in temperature and fluid weight resulted in minimal change in fluid behavior. Figure 9(a) compares the yield point of two different weight formulations (12.1 pounds per gallon and 12.4 pounds per gallon) of a fluid of the present invention at two different temperatures (40 degrees Fahrenheit and 120 degrees Fahrenheit). The yield point is unexpectedly lower at 40 degrees than at 120 degrees. Prior art oil-based fluids typically have lower yield points at higher temperatures, as traditional or prior art oils tend to thin or have reduced viscosity as temperatures increase. In contrast, the fluid of the invention can be thinned at lower temperatures without significantly affecting the viscosity of the fluid at higher temperatures. This feature or characteristic of the invention is a further indicator that the invention will provide good performance as a drilling fluid and will provide low ECDs. Moreover, this characteristic indicates the ability of the fluid to maintain viscosity at higher temperatures.

Figure 10 compares the viscosity of a base fluid for comprising a drilling fluid of the present invention with known base fluids of some prior art invert emulsion drilling fluids. The base fluid for the drilling fluid of the present invention is one of the thickest or most viscous. Yet when comprising a drilling fluid of the invention, the drilling fluid has low ECDs, provides good suspension of drill cuttings, satisfactory particle plugging and minimal fluid loss in use. Such surprising advantages of the drilling fluids of the invention are believed to be facilitated in part by a synergy or compatibility of the base fluid with appropriate thinners for the fluid.

Thinners disclosed in International Patent Application Publication Nos. WO2002/053675 and WO/2002/053676 of Halliburton Energy Services, Inc., Cognis Deutschland GmbH & Co KG., Heinz Muller, Jeff Kirsner (co-inventor of the present invention) and Kimberly

Burrows (co-inventor of the present invention), both filed December 29, 2000 and entitled "Thinners for Invert Emulsions," are particularly useful in the present invention for effecting such "selective thinning" of the fluid of the present invention; that is thinning at lower temperatures without rendering the fluid too thin at higher temperatures. Such thinners may have the following general formula: $R-(C_2H_4O)_n(C_3H_6O)_m(C_4H_8O)_k-H$ ("formula I"), where R is a saturated or unsaturated, linear or branched alkyl radical having about 8 to about 24 carbon atoms, n is a number ranging from about 1 to about 10, m is a number ranging from about 0 to about 10, and k is a number ranging from about 0 to about 10. Preferably, R has about 8 to about 18 carbon atoms; more preferably, R has about 12 to about 18 carbon atoms; and most preferably, R has about 12 to about 14 carbon atoms. Also, most preferably, R is saturated and linear.

The thinner may be added to the drilling fluid during initial preparation of the fluid or later as the fluid is being used for drilling or well service purposes in the formation. The quantity added is an effective amount to maintain or effect the desired viscosity of the drilling fluid. For purposes of this invention, an "effective amount" of thinner of formula (I) is preferably from about 0.5 to about 15 pounds per barrel of drilling fluid or mud. A more preferred amount of thinner ranges from about 1 to about 5 pounds per barrel of drilling fluid and a most preferred amount is about 1.5 to about 3 pounds thinner per barrel of drilling fluid.

The compositions or compounds of formula (I) may be prepared by customary techniques of alkoxylation, such as alkoxyating the corresponding fatty alcohols with ethylene oxide and/or propylene oxide or butylene oxide under pressure and in the presence of acidic or alkaline catalysts as is known in the art. Such alkoxylation may take place blockwise, i.e., the fatty alcohol may be reacted first with ethylene oxide, propylene oxide or butylene oxide and subsequently, if desired, with one or more of the other alkylene oxides. Alternatively, such alkoxylation may be conducted randomly, in which any desired mixture of ethylene oxide, propylene oxide and/or butylene oxide is reacted with the fatty alcohol.

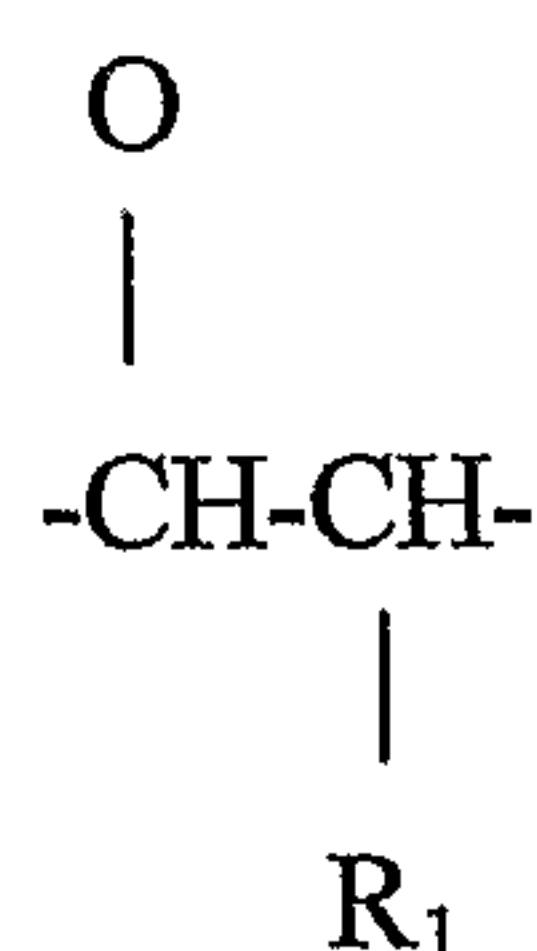
In formula (I), the subscripts n and m respectively represent the number of ethylene oxide (EO) and propylene oxide (PO) molecules or groups in one molecule of the alkoxyated fatty alcohol. The subscript k indicates the number of butylene oxide (BO)

molecules or groups. The subscripts n , m , and k need not be integers, since they indicate in each case statistical averages of the alkoxylation. Included without limitation are those compounds of the formula (I) whose ethoxy, propoxy, and/or butoxy group distribution is very narrow; such as for example, “narrow range ethoxylates” also called “NREs” by those skilled in the art.

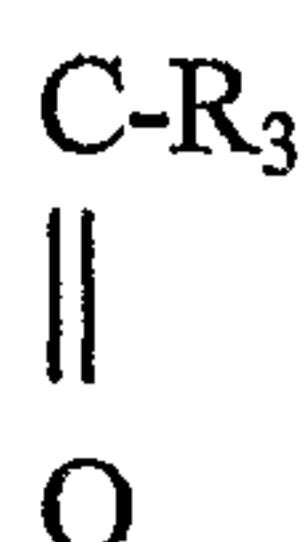
To accomplish the purposes of this invention, the compound of formula (I) must contain at least one ethoxy group. Preferably, the compound of formula I will also contain at least one propoxy group (C_3H_6O-) or butoxy group (C_4H_8O-). Mixed alkoxides containing all three alkoxide groups—ethylene oxide, propylene oxide, and butylene oxide—are possible for the invention but are not preferred.

Preferably, for use according to this invention, the compound of formula (I) will have a value for m ranging from about 1 to about 10 with k zero or a value for k ranging from about 1 to about 10 with m zero. Most preferably, m will be about 1 to about 10 and k will be zero.

Alternatively, such thinners may be a non-ionic surfactant which is a reaction product of ethylene oxide, propylene oxide and/or butylene oxide with C_{10-22} carboxylic acids or C_{10-22} carboxylic acid derivatives containing at least one double bond in position 9/10 and/or 13/14 having units of the general formula:



(“formula II”) where R_1 is a hydrogen atom or an OH group or a group OR_2 , where R_2 is an alkyl group of about 1 to about 18 carbon atoms, or an alkenyl group of about 2 to about 18 carbon atoms or a group of the formula:



where R_3 is a hydrogen atom, or an alkyl group of about 1 to about 21 carbon atoms or an alkylene group of about 2 to about 21 carbon atoms. A formula (II) thinner may be used alone or may be used in combination with a formula (I) thinner or co-thinner.

Preferred commercially available thinners include, for example, products having the tradenames COLDTROL® (alcohol derivative), OMC2™ (oligomeric fatty acid), ATC® (modified fatty acid ester), to be used alone or in combination, and available from Halliburton Energy Services, Inc. in Houston, Texas.

The formulations of the fluids of the invention, and also the formulations of the prior art isomerized olefin based drilling fluids, used in drilling the boreholes cited in the data above, vary with the particular requirements of the subterranean formation. Table 3 below, however, provides example formulations and properties for these two types of fluids discussed in the field data above. All trademarked products in Table 3 are available from Halliburton Energy Services, Inc. in Houston, Texas, including: LE MUL™ emulsion stabilizer (a blend of oxidized tall oil and polyaminated fatty acid); LE SUPERMUL™ emulsifier (polyaminated fatty acid); DURATONE® HT filtration control agent (organophilic leonardite); ADAPTA® HP filtration control agent (copolymer particularly suited for providing HPHT filtration control in non-aqueous fluid systems); RHEMOD L™ suspension agent/viscosifier (modified fatty acid); GELTONE® II viscosifier (organophilic clay); VIS-PLUS® suspension agent (carboxylic acid); BAROID® weighting agent (ground barium sulfate); and DEEP-TREAT® wetting agent/thinner (sulfonate sodium salt). In determining the properties in Table 3, samples of the fluids were sheared in a Silverson commercial blender at 7,000 rpm for 10 minutes, rolled at 150 degrees Fahrenheit for 16 hours, and stirred for 10 minutes. Measurements were taken with the fluids at 120 degrees Fahrenheit, except where indicated otherwise.

TABLE 3

Example Formulations

Fluids and Compounds	ACCOLADE™ System	Isomerized Olefin Based Invert Emulsion Drilling Fluid
ACCOLADE™ Base (bbl)	0.590	-----
SFT™ Base (bbl)	-----	0.568
LE MUL™ ¹ (lb)	-----	4
LE SUPERMUL™ ² (lb)	10	6
Lime (lb)	1	4
DURATONE® HT ³ (lb)	-----	4
Freshwater (bbl)	0.263	0.254
ADAPTA® HP ⁴ (lb)	2	-----
RHEMOD L™ ⁵ (lb)	1	-----
GELTONE® II ⁶ (lb)	-----	5
VIS-PLUS® ⁷ (lb)	-----	1.5
BAROID® ⁸ (lb)	138	138
Calcium chloride (lb)	32	31
DEEP-TREAT® ⁹ (lb)	-----	2

¹ Blend of oxidized tall oil and polyaminated fatty acid emulsion stabilizer.² Polyaminated fatty acid emulsifier.³ Organophilic leonardite filtration control agent.⁴ Copolymer HTHP filtration control agent for non-aqueous systems.⁵ Modified fatty acid suspension agent/viscosifier.⁶ Organophilic clay viscosifier.⁷ Carboxylic acid suspension agent.⁸ Ground barium sulfate weighting agent.⁹ Sulfonate sodium salt wetting agent/thinner.

TABLE 3—continued

B. Properties

	ACCOLADE™ System	Isomerized Olefin Based Invert Emulsion Drilling Fluid
Plastic Viscosity (cP)	19	19
Yield Point (lb/100 ft ²)	13	14
10 second gel (lb/100 ft ²)	9	7
10 minute gel (lb/100 ft ²)	12	9
HPHT Temperature (°F)	225	200
HPHT @ 500 psid (mL)	0.8	1.2
Electrical stability (volts)	185	380
Fann™ Dial Readings:		
600 rpm	51	52
300 rpm	32	33
200 rpm	25	26
100 rpm	18	18
6 rpm	7	7
3 rpm	5	6

The present invention is directed to using invert emulsion based drilling fluids that contain fragile gels or exhibit fragile gel behavior in drilling operations, such as drilling, running casing, and cementing. The present invention is also directed to reducing the loss of drilling fluids or drilling muds during such drilling operations by employing invert emulsion based drilling fluids that contain fragile gels or exhibit fragile gel behavior, and that preferably provide low ECDs. [0050] The invert emulsion drilling fluids of the present invention have an invert emulsion base. This base is not limited to a single formulation. Test data discussed above is from example invert emulsion drilling fluids of the invention comprising a blend of one or more esters and one or more isomerized, or internal,

olefins ("ester blend") such as described in U.S. Patent Application Publication No. 2003/0036484 of Jeff Kirsner (co-inventor of the present invention), Kenneth W. Pober and Robert W. Pike, filed August 14, 2001, entitled "Blends of Esters with Isomerized Olefins and Other Hydrocarbons as Base Oils for Invert Emulsion Oil Muds". In such blend, preferably the esters will comprise at least about 10 weight percent of the blend and may comprise up to about 99 weight percent of the blend, although the esters may be used in any quantity. Preferred esters for blending are comprised of about C₆ to about C₁₄ fatty acids and alcohols, and are particularly or more preferably disclosed in U.S. Patent No. Re. 36,066, reissued January 25, 1999 as a reissue of U.S. Patent No. 5,232,910, assigned to Henkel KgaA of Dusseldorf, Germany, and Baroid Limited of London, England, and in U.S. Patent No. 5,252,554, issued Oct. 12, 1993, and assigned to Henkel Kommanditgesellschaft auf Aktien of Dusseldorf, Germany and Baroid Limited of Aberdeen, Scotland. Esters disclosed in U.S. Patent No. 5,106,516, issued Apr. 21, 1992, and U.S. Patent No. 5,318,954, issued June 7, 1984, both assigned to Henkel Kommanditgesellschaft auf Aktien, of Dusseldorf, Germany, may also be used. The most preferred esters for use in the invention are comprised of about C₁₂ to about C₁₄ fatty acids and 2-ethyl hexanol or about C₈ fatty acids and 2-ethyl hexanol. These most preferred esters are available commercially under tradenames PETROFREE® and PETROFREE LV™, respectively, from Halliburton Energy Services, Inc. in Houston, Texas. Although esters made with fatty acids and alcohols are preferred, esters made other ways, such as from combining olefins with either fatty acids or alcohols, may also be effective.

Isomerized, or internal, olefins for blending with the esters for an ester blend may be any such olefins, straight chain, branched, or cyclic, preferably having about 10 to about 30 carbon atoms. Isomerized, or internal, olefins having about 40 to about 70 weight percent C₁₆ and about 20 to about 50 weight percent C₁₈ are especially preferred. An example of an isomerized olefin for use in an ester blend in the invention that is commercially available is SF™ Base fluid, available from Halliburton Energy Services, Inc. in Houston, Texas. Alternatively, other hydrocarbons such as paraffins, mineral oils, glyceride triesters, or combinations thereof may be substituted for or added to the olefins in the ester blend. Such other hydrocarbons may comprise from about 1 weight percent to about 99 weight

percent of such blend.

Invert emulsion drilling fluids may be prepared comprising SFTM Base without the ester, however, such fluids are not believed to provide the superior properties of fluids of the invention with the ester. Field data discussed above has demonstrated that the fluids of the invention are superior to prior art isomerized olefin based drilling fluids, and the fluids of the invention have properties especially advantageous in subterranean wells drilled in deep water. Moreover, it is believed that the principles of the method of the invention may be used with invert emulsion drilling fluids that form fragile gels or yield fragile gel behavior, provide low ECDs, and have (or seem to have) viscoelasticity that may not be comprised of an ester blend. One example of such a fluid may comprise a polar solvent instead of an ester blend.

Other examples of possible suitable invert emulsion bases for the drilling fluids of the present invention include isomerized olefins blended with other hydrocarbons such as linear alpha olefins, paraffins, or naphthenes, or combinations thereof ("hydrocarbon blends").

Paraffins for use in blends comprising invert emulsions for drilling fluids for the present invention may be linear, branched, poly-branched, cyclic, or isoparaffins, preferably having about 10 to about 30 carbon atoms. When blended with esters or other hydrocarbons such as isomerized olefins, linear alpha olefins, or naphthenes in the invention, the paraffins should comprise at least about 1 weight percent to about 99 weight percent of the blend, but preferably less than about 50 weight percent. An example of a commercially available paraffin suited for blends useful in the invention is called tradename XP-07TM, available from Halliburton Energy Services, Inc. in Houston, Texas. XP-07TM is primarily a C₁₂₋₁₆ linear paraffin.

Examples of glyceride triesters for ester/hydrocarbon blends useful in blends comprising invert emulsions for drilling fluids for the present invention may include without limitation materials such as rapeseed oil, olive oil, canola oil, castor oil, coconut oil, corn oil, cottonseed oil, lard oil, linseed oil, neatsfoot oil, palm oil, peanut oil, perilla oil, rice bran oil, safflower oil, sardine oil, sesame oil, soybean oil, and sunflower oil.

Naphthenes or naphthenic hydrocarbons for use in blends comprising invert emulsions for drilling fluids for the present invention may be any saturated, cycloparaffinic

compound, composition or material with a chemical formula of C_nH_{2n} where n is a number about 5 to about 30.

In still another embodiment, a hydrocarbon blend might be blended with an ester blend to comprise an invert emulsion base for a drilling fluid of the present invention.

The exact proportions of the components comprising an ester blend (or other blend or base for an invert emulsion) for use in the present invention will vary depending on drilling requirements (and characteristics needed for the blend or base to meet those requirements), supply and availability of the components, cost of the components, and characteristics of the blend or base necessary to meet environmental regulations or environmental acceptance. The manufacture of the various components of the ester blend (or other invert emulsion base) will be understood by one skilled in the art.

Further, the invert emulsion drilling fluid of the invention or for use in the present invention has added to it or mixed with the invert emulsion base, other fluids or materials needed to comprise a complete drilling fluid. Such materials may include for example additives to reduce or control temperature rheology or to provide thinning, such as, for example, additives having the tradenames COLDTROL®, RHEMOD L™, ATC®, and OMC2™; additives for providing temporary increased viscosity for shipping (transport to the well site) and for use in sweeps, such as, for example an additive having the tradename TEMPERUS™ (modified fatty acid); additives for filtration control, such as, for example additives having the tradename ADAPTA HP®; additives for high temperature high pressure control (HTHP) and emulsion stability, such as, for example, additives having the tradename FACTANT™ (highly concentrated tall oil derivative); and additives for emulsification, such as, for example additives having the tradename LE SUPERMUL™ (polyaminated fatty acid). Blends of thinners such as the OMC2™, COLDTROL®, and ATC® thinners can be more effective in fluids of the invention than a single one of these thinners. All of the aforementioned trademarked products are available from Halliburton Energy Services, Inc. in Houston, Texas, U.S.A.

The invert emulsion drilling fluid of the present invention preferably does not have added to it any organophilic clays. The fluid of the invention does not need organophilic clay or organophilic lignites to provide it needed viscosity, suspension characteristics,

or filtration control to carry drill cuttings to the well surface. Moreover, the lack of organophilic clays and organophilic lignites in the fluid is believed to enhance the tolerance of the fluid to the drill cuttings. That is, the lack of organophilic clays and organophilic lignites in the fluid of the invention is believed to enable the fluid to suspend and carry drill cuttings without significant change in the fluid's rheological properties.

The foregoing description of the invention is intended to be a description of preferred embodiments. Various changes in the details of the described fluids and method of use can be made without departing from the intended scope of this invention as defined by the appended claims.

CLAIMS:

1. A method of drilling in a subterranean formation comprising the steps of:
providing an invert emulsion drilling fluid having substantially equal dial readings at 40°F (4.4°C) and at 120°F (48.9°C) when measured at 3 rpm or 6 rpm using a FANN viscometer at atmospheric pressure; and
drilling in the subterranean formation with the drilling fluid.
2. The method of Claim 1 wherein the drilling fluid comprises:
a continuous phase comprising at least one component selected from the group consisting of: olefins, paraffin hydrocarbons, esters, mineral oil hydrocarbons, glyceride triesters, and naphthenic hydrocarbons; and
an internal phase comprising water.
3. The method of Claim 2 wherein the drilling fluid further comprises a modified fatty acid rheology modifier comprising dimeric and trimeric fatty acids.
4. The method of Claim 2 wherein the drilling fluid further comprises a copolymer filtration control agent.
5. The method of Claim 1 wherein the drilling fluid is free of organophilic clay.
6. The method of Claim 1 wherein the drilling fluid is substantially free of lignite.
7. The method of Claim 1 wherein the drilling fluid is free of organophilic clay and lignite.
8. The method of Claim 1 wherein the drilling fluid is free of an organophilic filtration control agent.

9. The method of Claim 1 wherein the drilling fluid has a lower yield point at a temperature of 40°F (4.4°C) than at a temperature of 120°F (48.9°C).
10. The method of Claim 1 wherein the drilling is performed in a wellbore in the subterranean formation at a water depth greater than 1,500 feet (457.2 m).
11. The method of Claim 1 wherein loss of the drilling fluid is less than 500 barrels of total drilling fluid when drilling, running casing and cementing a wellbore in the subterranean formation.
12. The method of Claim 1 wherein the drilling fluid further comprises a thinner that reduces the viscosity of the drilling fluid at 40°F (4.4°C) to a greater extent than it reduces the viscosity of the drilling fluid at 120°F (48.9°C).
13. The method of Claim 1 wherein the drilling fluid comprises:
a continuous phase,
an internal phase,
an emulsifier, and
a weighting agent;
and the method further comprises the steps of:
stopping the drilling while suspending the weighting agent in the drilling fluid;
measuring pressure with pressure-while-drilling equipment or instruments; and
resuming the drilling with substantially no pressure spike as detected by the pressure-while-drilling equipment or instruments.
14. The method of Claim 1 wherein the drilling fluid comprises:
a continuous phase,
an internal phase,
an emulsifier, and
a weighting agent;

and the method further comprises the steps of:

maintaining an average Equivalent Circulating Density (ECD) of less than 0.5 over an interval of at least 200 feet (60.96 m) while drilling; and

stopping the drilling while suspending the weighting agent in the drilling fluid.

15. The method of Claim 1 wherein the drilling fluid comprises:

a continuous phase,

an internal phase,

an emulsifier, and

a weighting agent;

and the method further comprises the steps of:

stopping the drilling with substantially no sag in the drilling fluid;

measuring the pressure with pressure-while-drilling equipment or instruments;

and

resuming the drilling with substantially no pressure spike as detected by the pressure-while drilling equipment or instruments.

16. The method of Claim 1 wherein the drilling fluid comprises:

a continuous phase,

an internal phase,

an emulsifier, and

a weighting agent,

and the method further comprises the steps of:

maintaining an average ECD of less than 0.5 over an interval of at least 200 feet (60.96 m) while drilling; and

stopping the drilling with substantially no sag in the drilling fluid.

17. An invert emulsion drilling fluid having substantially equal dial readings at 40°F (4.4°C) and at 120°F (48.9°C) when measured at 3 rpm or 6 rpm using a FANN viscometer at atmospheric pressure; and for use in drilling in a subterranean formation.

18. The drilling fluid of Claim 17 comprising:
a continuous phase comprising at least one component selected from the group consisting of: olefins, paraffin hydrocarbons, esters, mineral oil hydrocarbons, glyceride triesters, and naphthenic hydrocarbons; and
an internal phase comprising water.
19. The drilling fluid of Claim 18 further comprising a modified fatty acid rheology modifier comprising dimeric and trimeric fatty acids.
20. The drilling fluid of Claim 18 wherein the drilling fluid further comprises a copolymer filtration control agent.
21. The drilling fluid of Claim 17 wherein the drilling fluid is free of organophilic clay.
22. The drilling fluid of Claim 17 wherein the drilling fluid is substantially free of lignite.
23. The drilling fluid of Claim 17 wherein the drilling fluid is free of organophilic clay and lignite.
24. The drilling fluid of Claim 17 wherein the drilling fluid is free of an organophilic filtration control agent.
25. The drilling fluid of Claim 17 wherein the drilling fluid has a lower yield point at a temperature of 40°F (4.4°C) than at a temperature of 120°F (48.9°C).
26. The drilling fluid of Claim 17 wherein the drilling is performed in a wellbore in the subterranean formation at a water depth greater than 1,500 feet (457.2 m)

27. The drilling fluid of Claim 17 wherein loss of the drilling fluid is less than 500 barrels of total drilling fluid when drilling, running casing and cementing a wellbore in the subterranean formation.

28. The drilling fluid of Claim 17 wherein the drilling fluid comprises a thinner that reduces the viscosity of the drilling fluid at 40°F (4.4°C) to a greater extent than it reduces the viscosity of the drilling fluid at 120°F (48.9°C).

29. The drilling fluid of Claim 17 wherein the drilling fluid comprises:
a continuous phase,
an internal phase,
an emulsifier, and
a weighting agent;
and wherein during the drilling in the subterranean formation with the drilling fluid, the drilling fluid:
suspends the weighting agent in the drilling fluid when the drilling is stopped
and
causes substantially no pressure spike to be detected when the drilling is resumed, when measuring pressure using pressure-while-drilling equipment or measurements.

30. The drilling fluid of Claim 17 wherein the drilling fluid comprises:
a continuous phase,
an internal phase,
an emulsifier, and
a weighting agent;
and wherein during the drilling in the subterranean formation, the drilling fluid:
maintains an average ECD of less than 0.5 over an interval of at least 200 feet (60.96 m); feet and
suspends the weighting agent in the drilling fluid when the drilling is stopped.

31. The drilling fluid of Claim 17 wherein the drilling fluid comprises;
a continuous phase,
an internal phase,
an emulsifier, and
a weighting agent;
and wherein during the drilling in the subterranean formation, the drilling fluid:

has substantially no sag when the drilling is stopped, and
causes substantially no pressure spike to be detected when the drilling is resumed, when measuring pressure using pressure-while-drilling equipment or measurements.
32. The drilling fluid of Claim 17 wherein the drilling fluid comprises:
a continuous phase,
an internal phase,
an emulsifier, and
a weighting agent;
and wherein during the drilling in the subterranean formation with the drilling fluid, the drilling fluid:

maintains an average ECD of less than 0.5 over an interval of at least 200 feet (60.96 m) and

has substantially no sag when the drilling is stopped.
33. The method of Claim 1 wherein the invert emulsion fluid has substantially equal dial readings at 40°F (4.4°C) and at 120°F (48.9) when measured at 3 rpm using a FANN viscometer at atmospheric pressure.
34. The method of Claim 1 wherein the invert emulsion drilling fluid has substantially equal dial readings at 40°F (4.4°C) and at 120°F (48.9°C) when measured at 6 rpm using a FANN viscometer at atmospheric pressure.

35. The drilling fluid of Claim 17 having substantially equal dial readings at 40°F (4.4°C) and at 120°F (48.9°C) when measured at 3 rpm using a FANN viscometer at atmospheric pressure.

36. The drilling fluid of Claim 17 having substantially equal dial readings at 40°F (4.4°C) and at 120°F (48.9°C) when measured at 6 rpm using a FANN viscometer at atmospheric pressure.

1/10

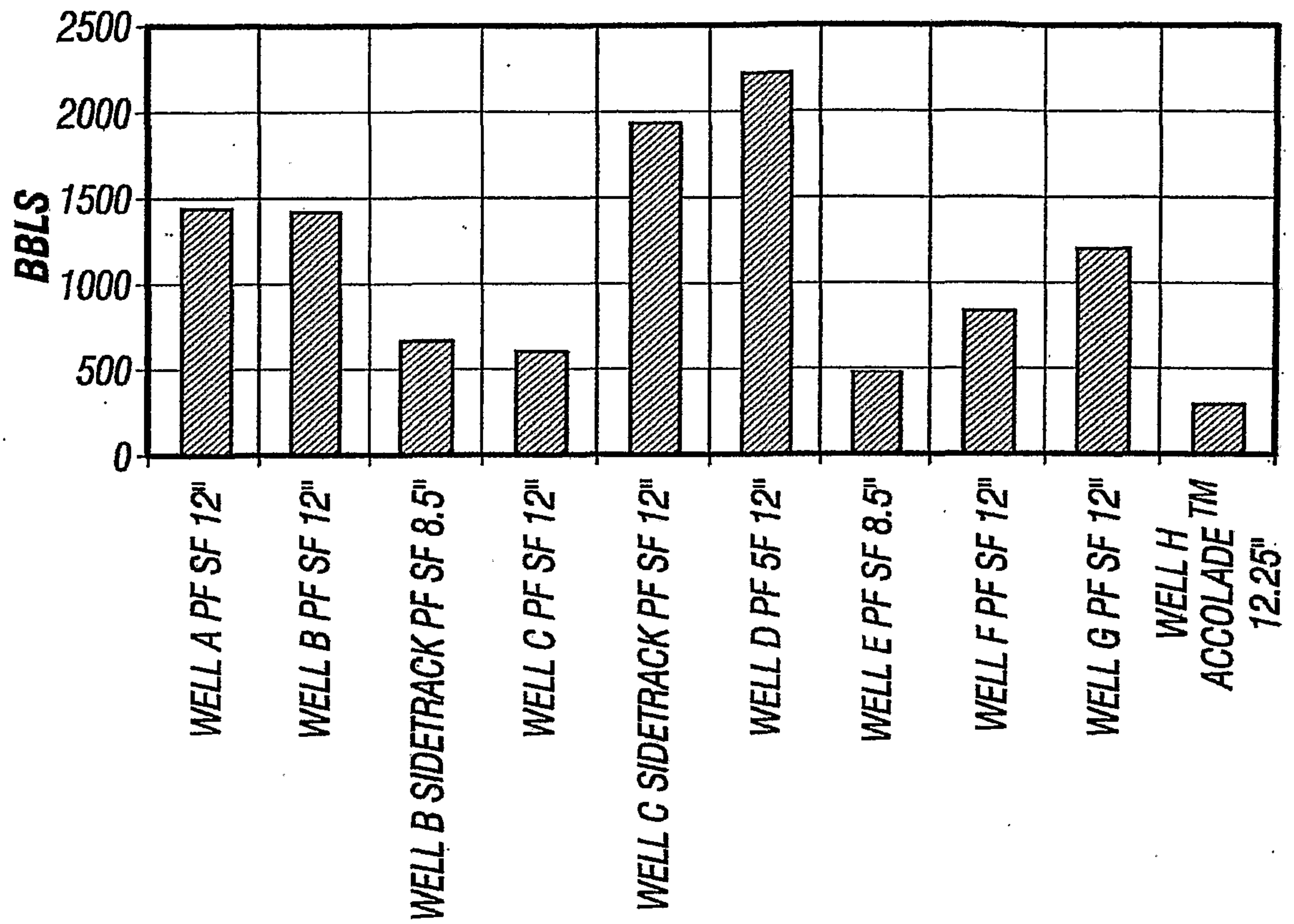


FIG. 1A

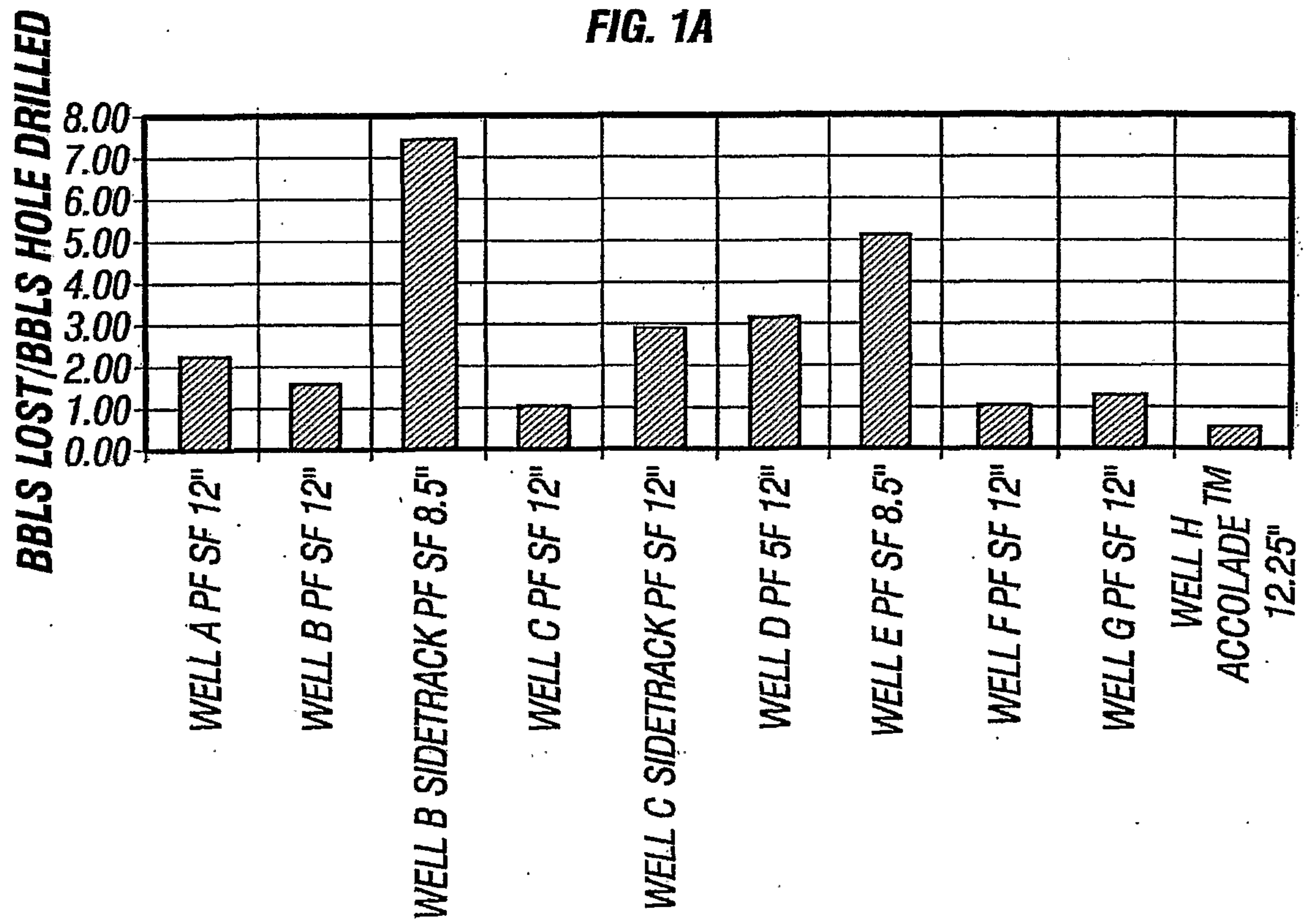
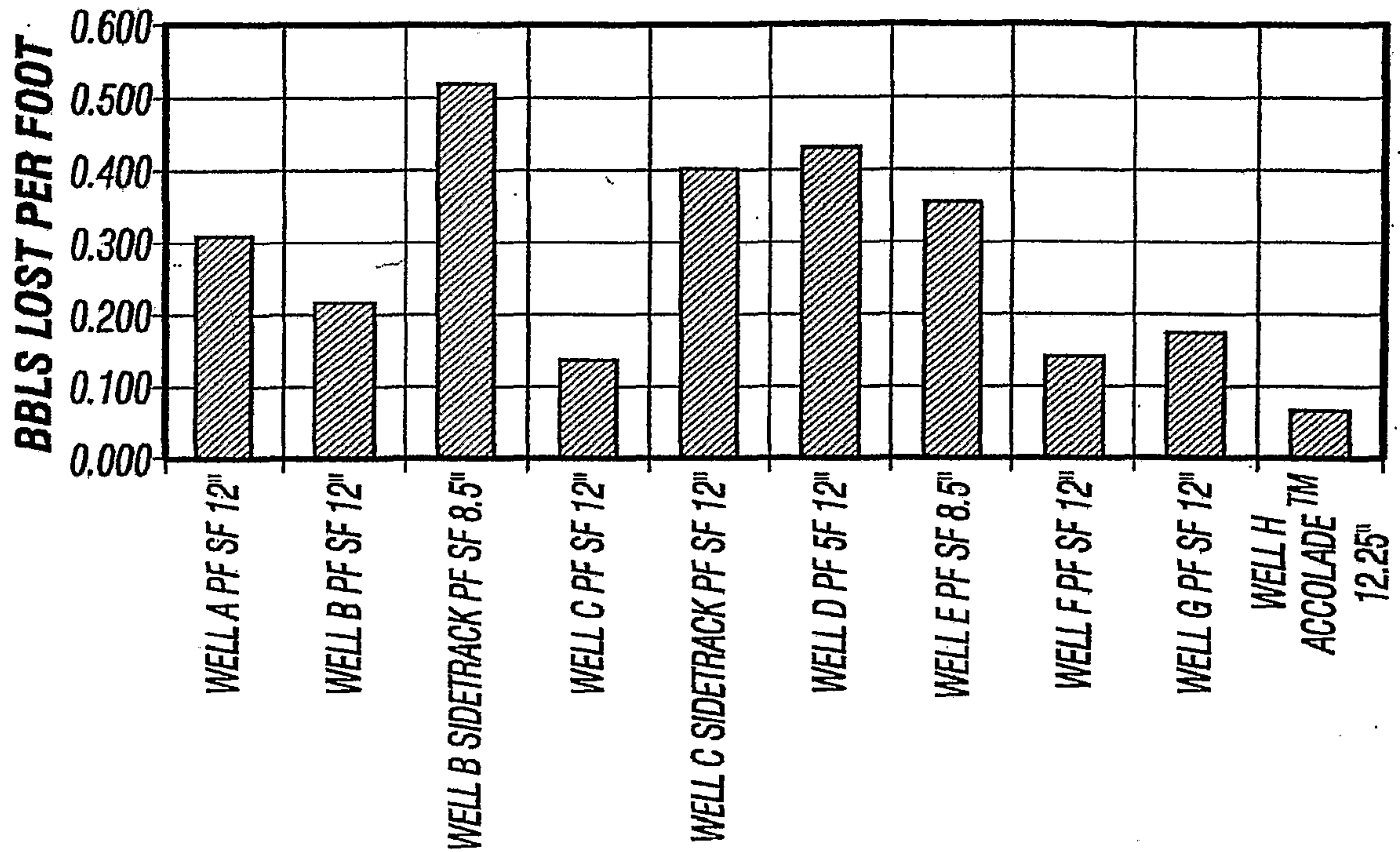
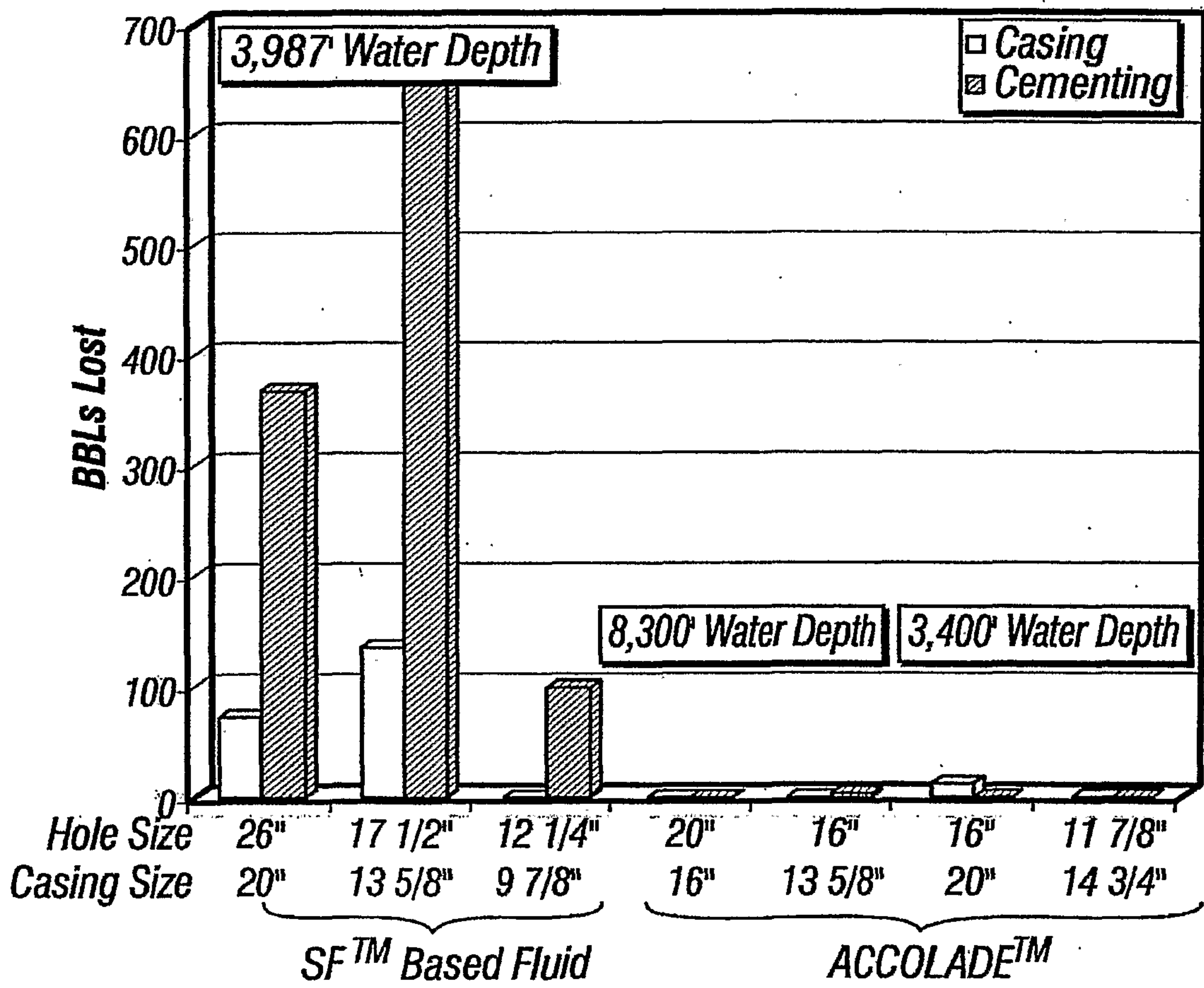
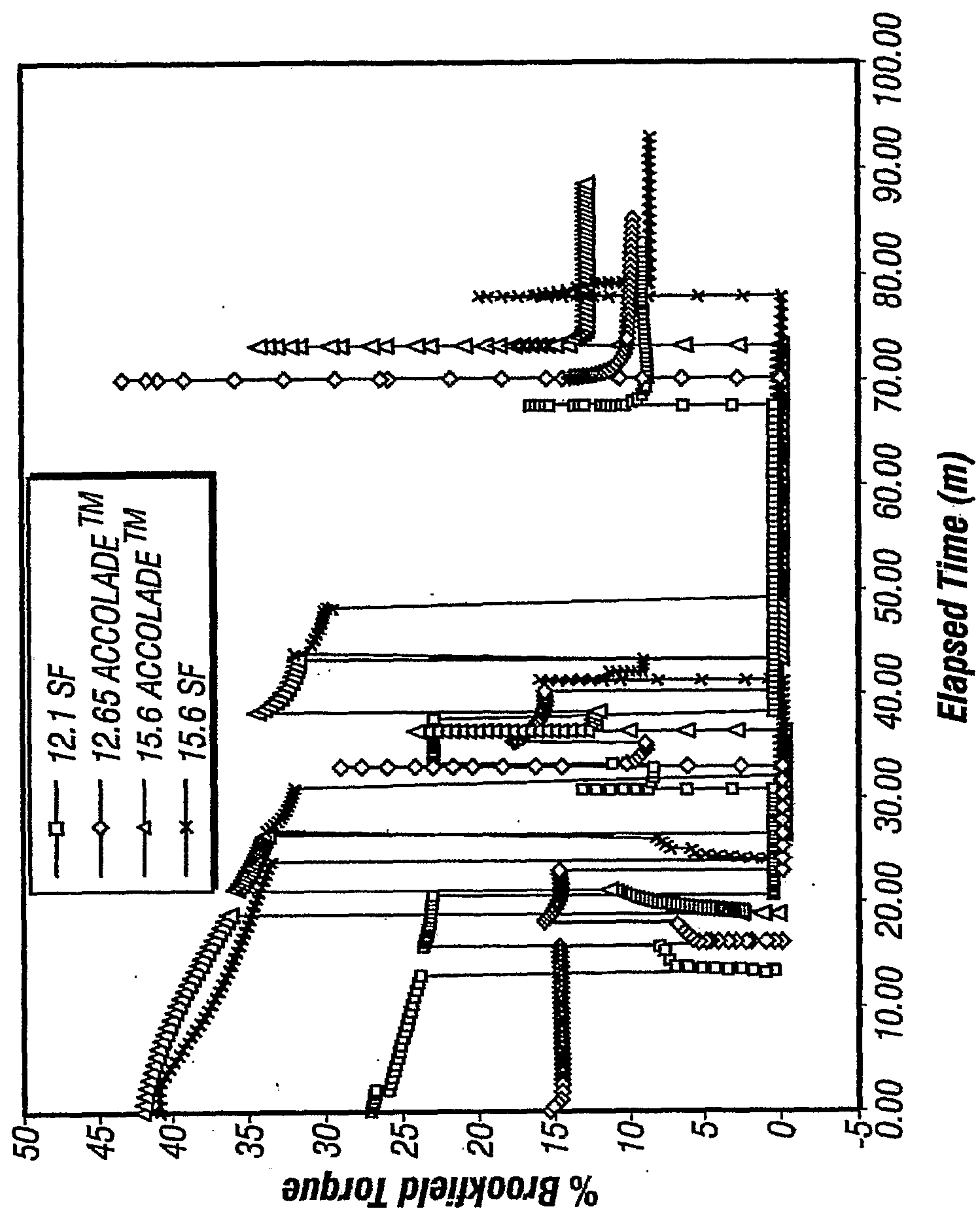


FIG. 1B

2/10**FIG. 1C****FIG. 2**

3/10



Elapsed Time (m)
FIG. 3

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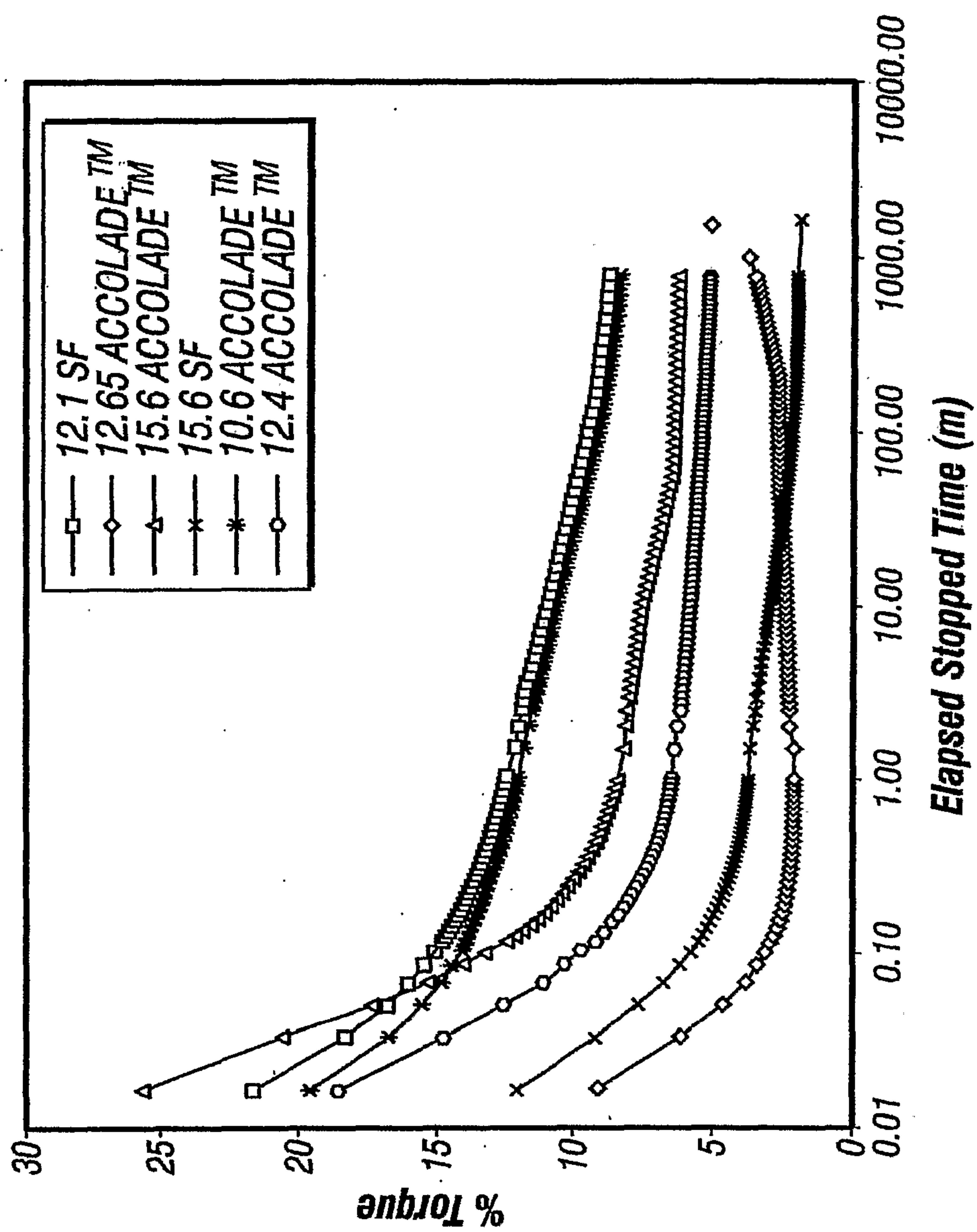
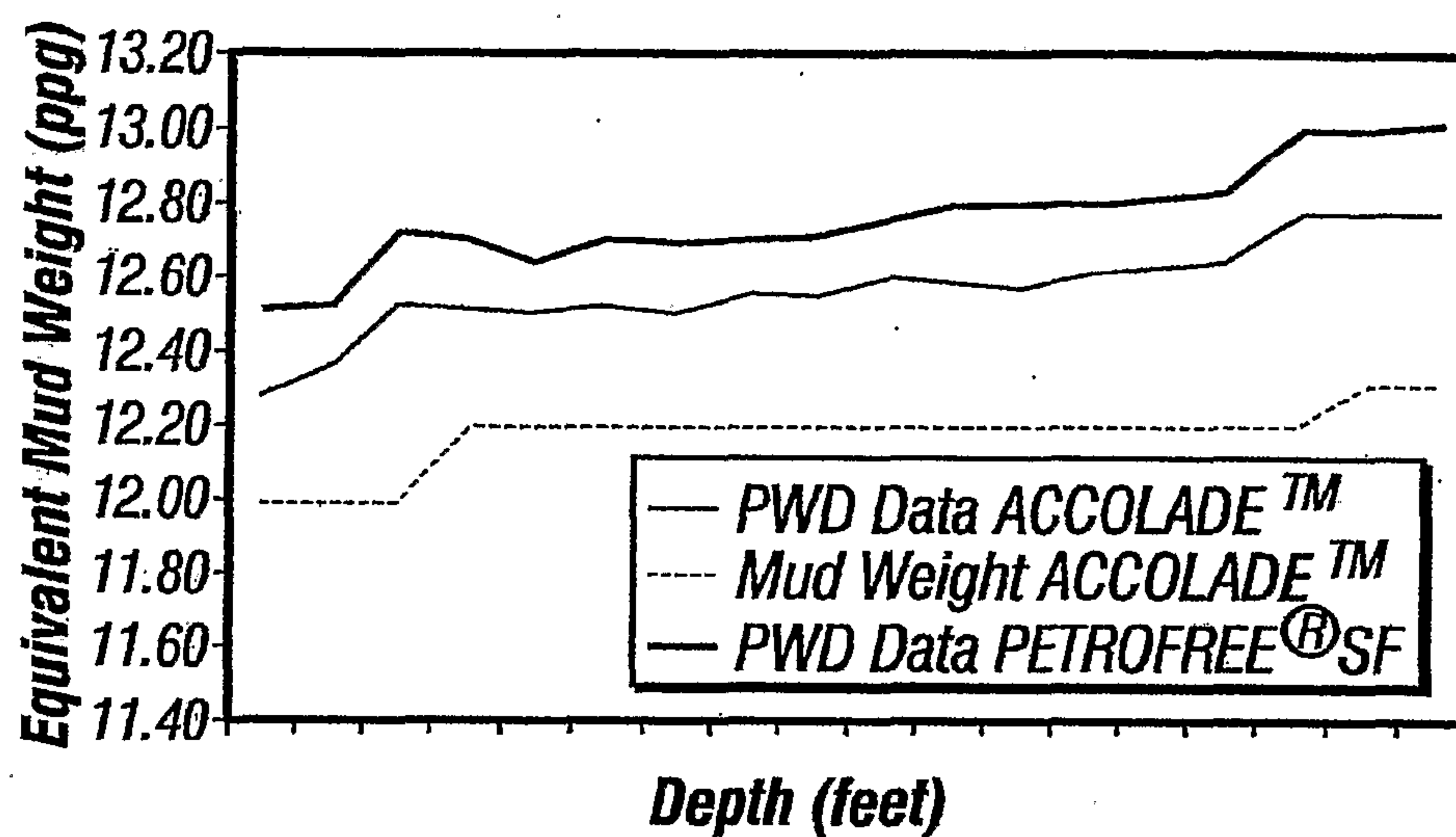
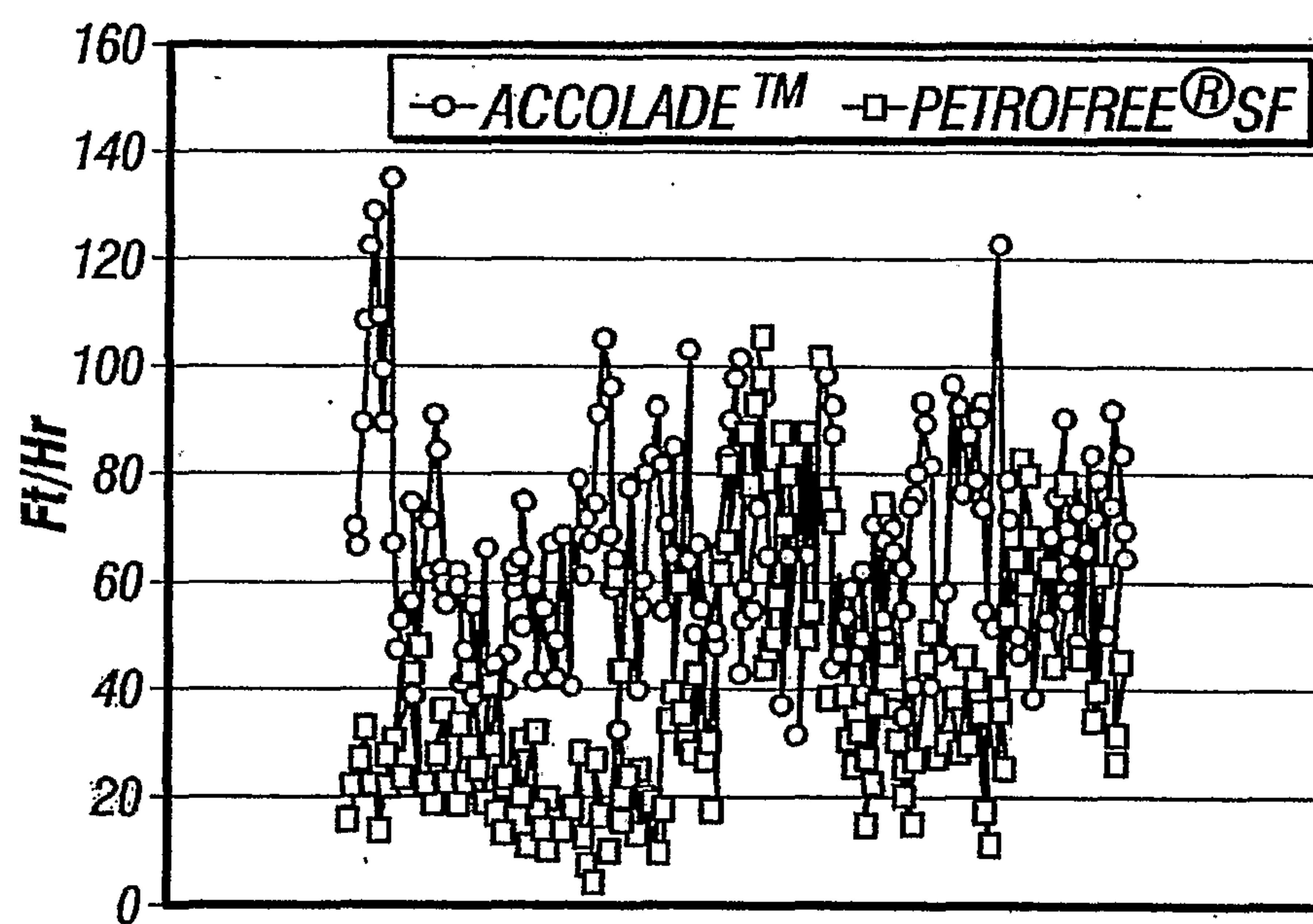
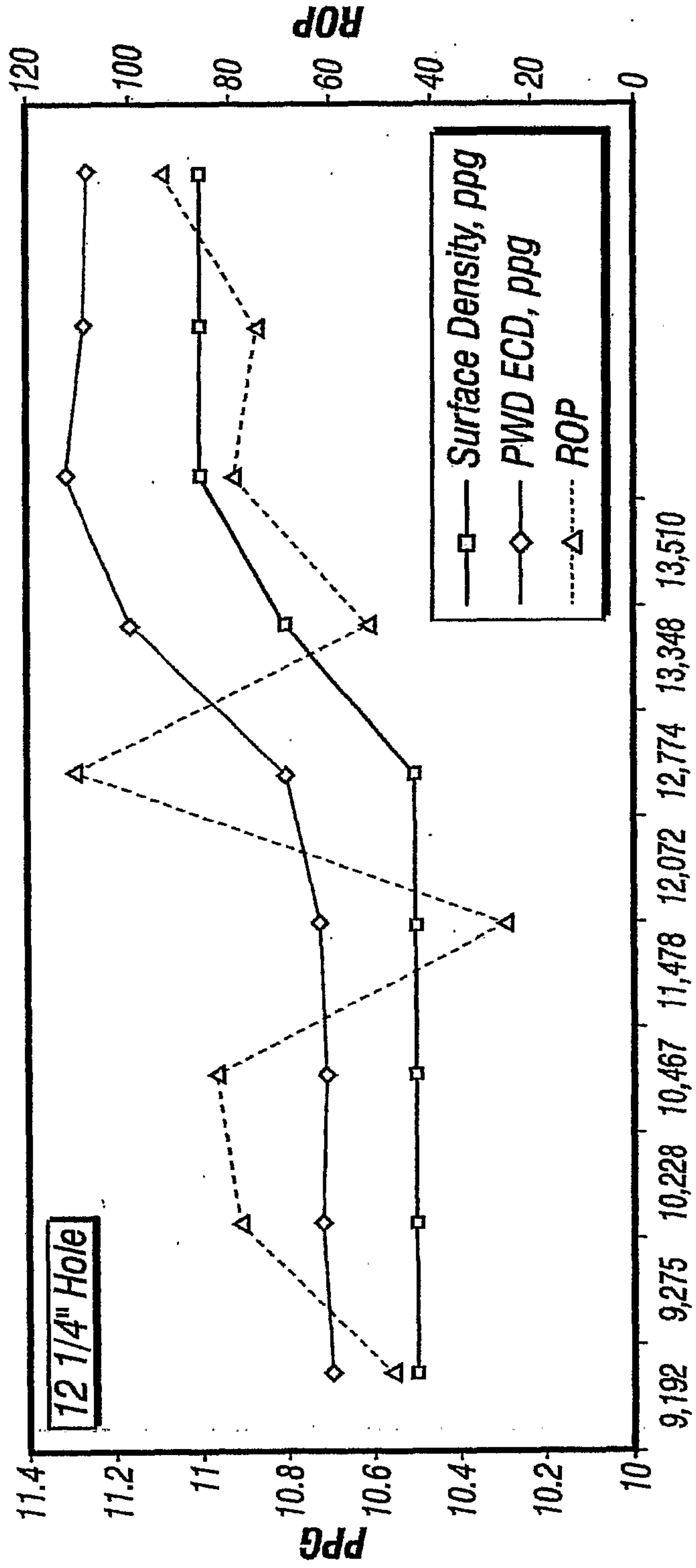


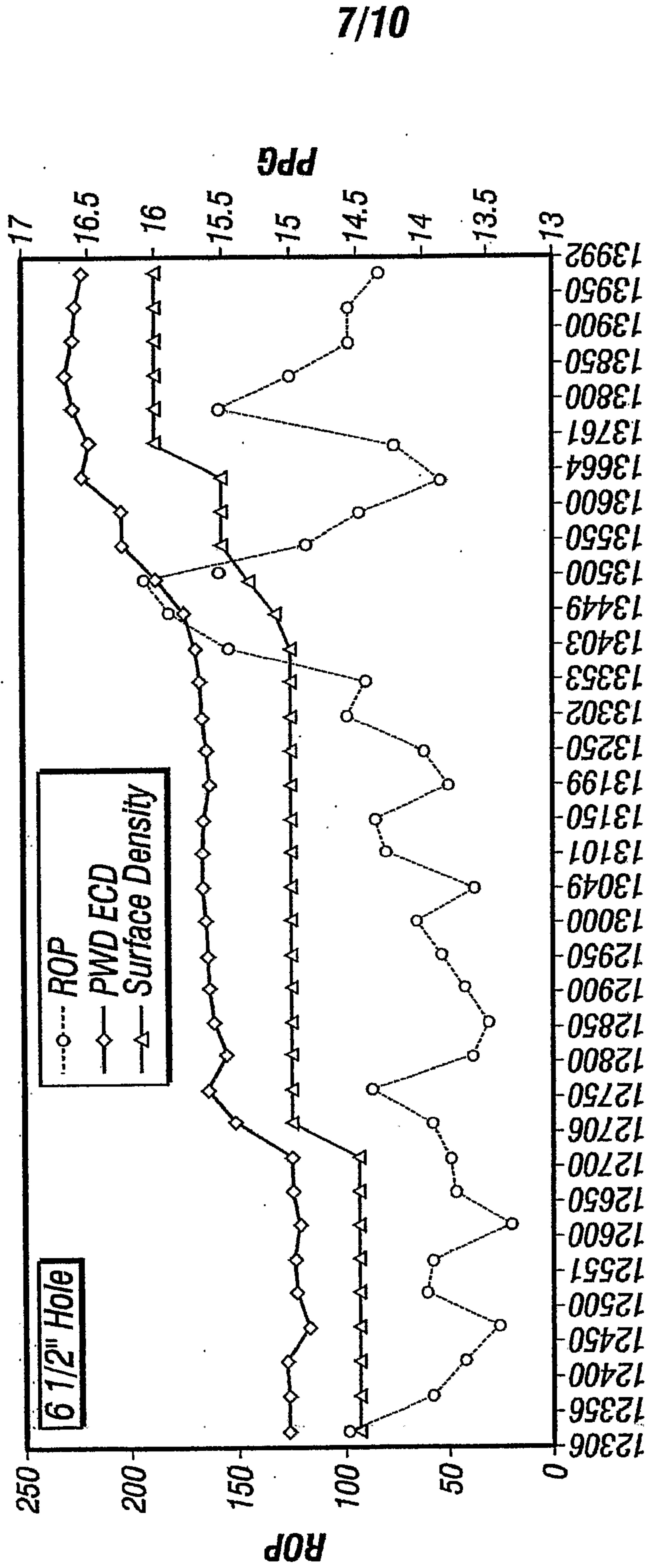
FIG. 4

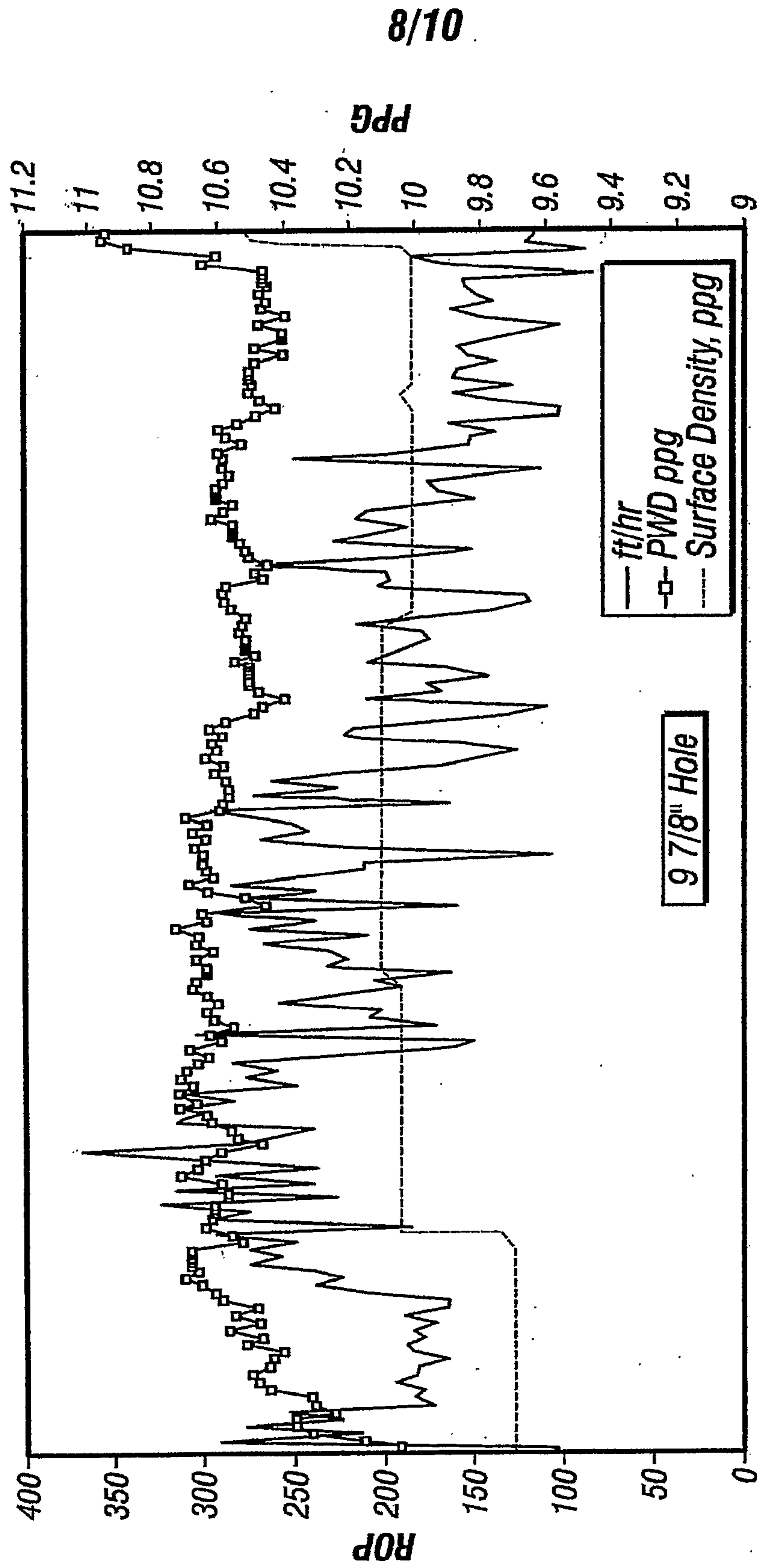
5/10**FIG. 5A****FIG. 5B**

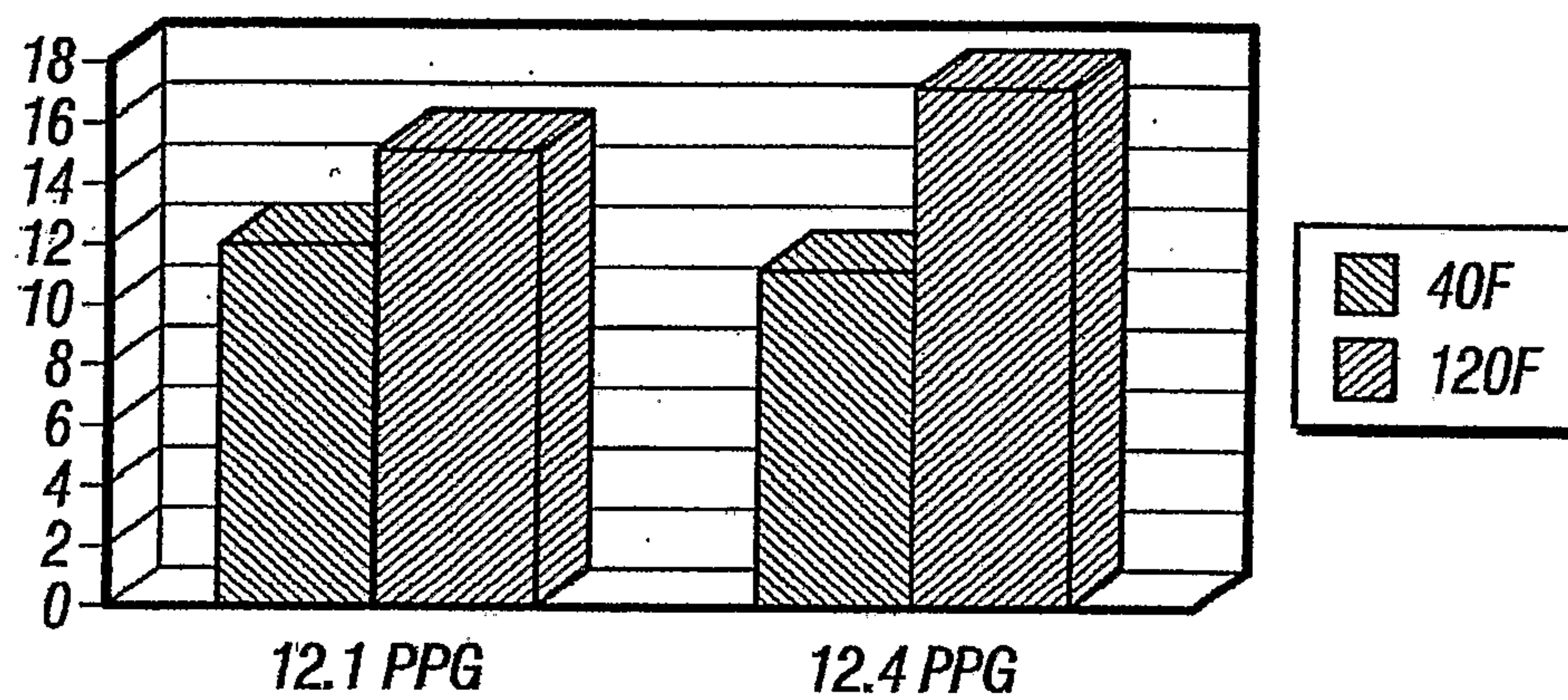
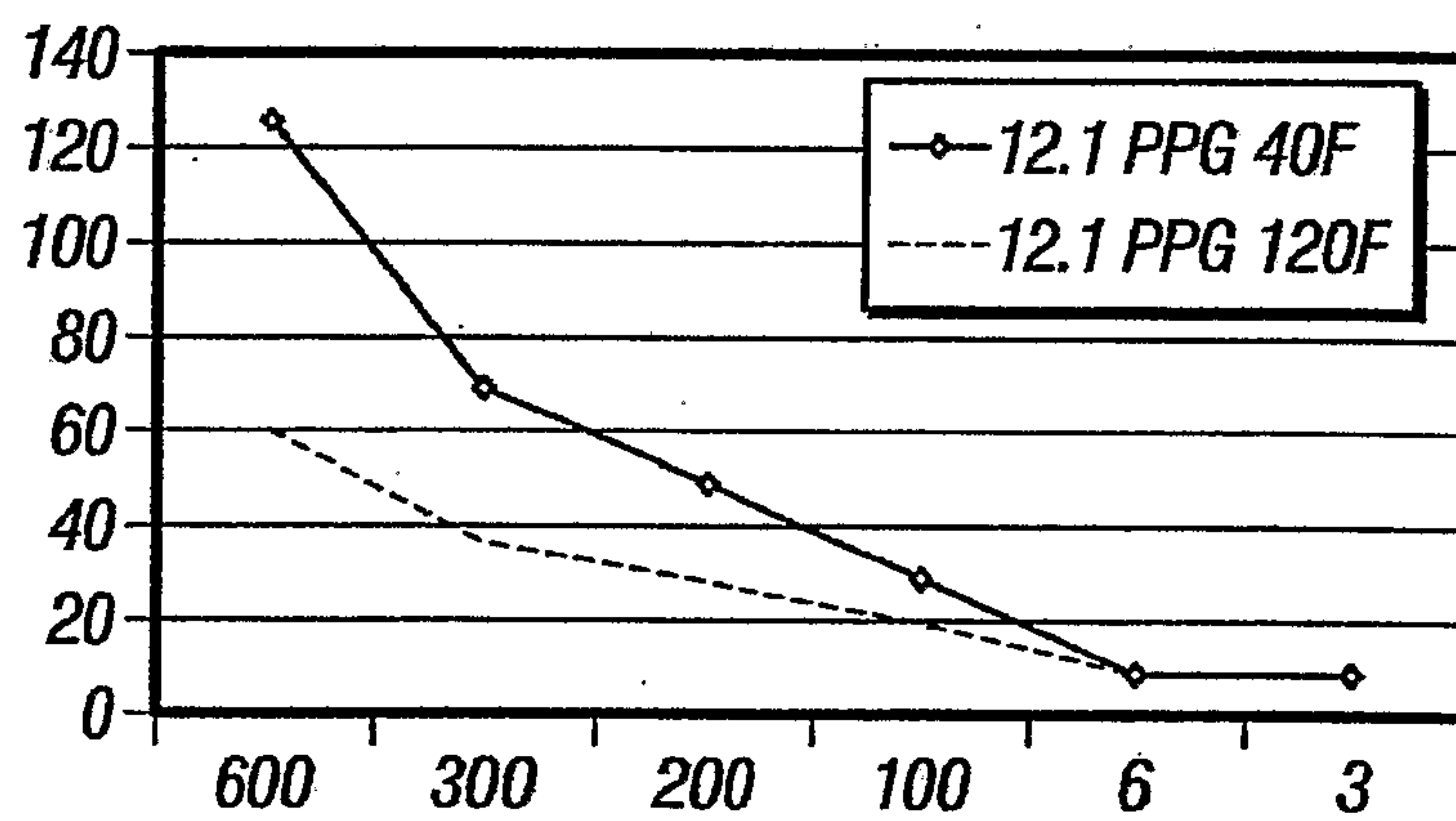
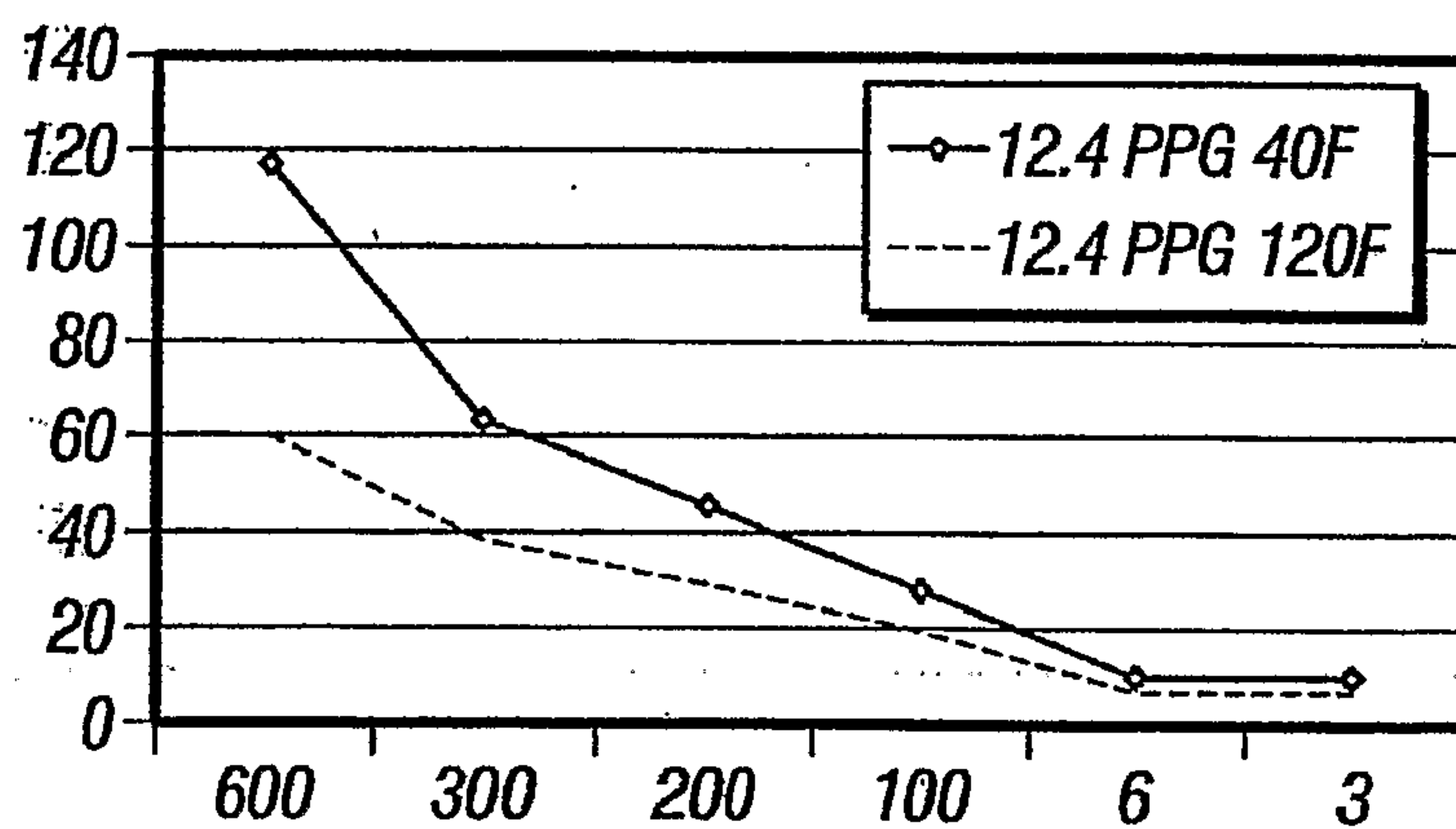
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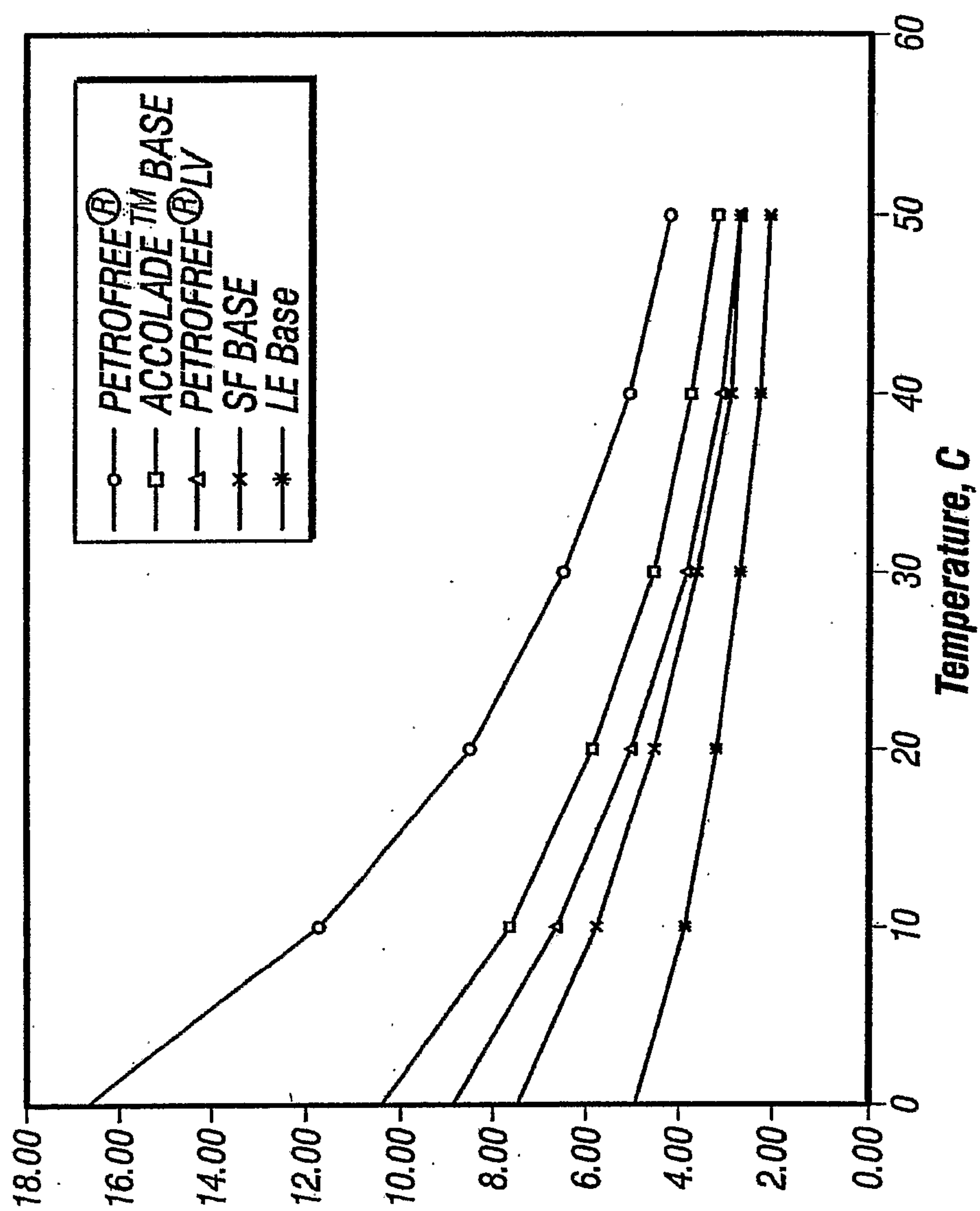


Depth
FIG. 6



**FIG. 8**

9/10**FIG. 9A****FIG. 9B****FIG. 9C**

10/10**FIG. 10**