



New Inhibitive Water-based Fluid Provided Drilling Performance Comparable to Invert Emulsion Systems in Reactive Shale Sections

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Abstract

In a Lavaca County, Texas field, most wells are drilled with conventional water-based fluids and diesel-based invert emulsion fluids. However, excellent drilling performance has been achieved with a high-performance, water-based fluid (HPWBF). The HPWBF enabled the drilling of a stable gauge hole at a rate of penetration (ROP) comparable to that achieved with invert emulsion systems. The system reduced costs and risks normally associated with running oil-based fluids.

In reactive shales, the HPWBF helped minimize hole washout, optimize hole cleaning, and improve the quality of cementing jobs. The HPWBF enabled a solids removal efficiency (SRE) in the 85% range, rivaling efficiencies achieved with invert emulsion systems. Product consumption and discharge volumes were significantly lowered compared to conventional WBFs, and haul-off and cleanup costs were reduced compared to invert emulsion fluids. In addition, standard equipment on most rigs was sufficient to maintain the desired properties.

This paper discusses the results of the SRE study of the Eaves No. 5 well drilled by Westport Resources (Westport Resources has since been acquired through merger by Kerr-McGee Corporation). A comprehensive analysis of ancillary costs associated with invert emulsion fluids is also detailed. The results indicate that the HPWBF can provide a viable alternative to drilling with invert emulsion systems.

Introduction

The use of polymers to enhance drilling fluid performance probably began when starches were added to viscosify saltwater and to control filtration. Since that time, polymer usage has become increasingly common in water-based fluids.

In 2002, new HPWBF fit-for-purpose fluids were introduced. To earn the designation HPWBF, fluids must 1) exhibit low colloidal content, 2) be highly inhibitive in reactive shales, 3) be run non-dispersed, and 4) exhibit a high degree of shear thinning.

The HPWBF system discussed in this paper is designed for land applications and is formulated with fresh or low-salinity water. Early use of this HPWBF system in Calhoun, Webb, and Zapata Counties (Texas)

produced favorable results. As a result, an operator elected to use this system to drill the intermediate interval of the Eaves No. 5 located in the Speaks Field of Lavaca County.

Seven offsets were investigated during the programming stage of this project. Intermediate sections typically were drilled from 2,800 to 10,600 ft. Intermediate casings were either 7 ⁵/₈- or 9 ⁵/₈-in. Difficulties encountered on some or all offset wells included:

- Treatment for carbonate contamination
- Logs not reaching bottom
- Swelling shale
- Packing off/Bridging
- Having to wash and ream to bottom
- Excessive cuttings due to sloughing shale
- Seepage losses
- Partial returns
- Lost returns
- Reduced pump rates to minimize losses
- Slow penetration rates
- Wellbore instability due to insufficient mud weight

System Features

The HPWBF system exhibits low colloidal solids content and is highly inhibitive, non-dispersed, and shear thinning. Low colloidal content is typically maintained with standard rig solids-removal equipment although supplementary equipment can further enhance solids reduction. The system is maintained without the use of dispersants or caustic materials. This absence of dispersants contributes to the reduced colloidal solids content. The highly inhibitive nature of the system can improve wellbore stability and help minimize washout tendencies. The polymeric composition of this system results in a highly shear-thinning fluid.

Low Colloidal Solids and ROP

Reducing solids concentrations can provide major advantages in any drilling fluid: lower plastic viscosities, better filter-cake quality, increased bit life, and improved penetration rates.² **Fig. 1** illustrates the effect that solids content has on penetration rate.

Maintaining a low colloidal content in a water-based

fluid system has been the greatest obstacle to achieving ROPs comparable to those obtained with invert emulsion systems. Minimizing the retention time that drilled solids remain in the fluid system is recommended in maintaining low colloidal content.³ The HPWBF system can provide a low colloidal content fluid system through the use of a high molecular weight (HMW), flocculating polymer. The encapsulating effect of this polymer on drilled cuttings helps reduce wellbore attrition and can result in fewer colloidal solids being generated. Minimal retention time is achieved when fine mesh screens are used to remove these larger drilled solids before further breakdown can take place.

The ROP achieved with the HPWBF used on the Eaves No. 5 well was compared with the ROP achieved on a well drilled in the same field using a diesel invert emulsion in the 12 1/4-in. intermediate section. Penetration rate data in the vertical portion of the well (± 3,300 ft) drilled with a diesel invert emulsion system was compared to ROP data from the well drilled with HPWBF. The invert emulsion fluid averaged 69.0 ft/hr in the vertical portion of the interval while the HPWBF system averaged 62.95 ft/hr for the entire interval.

Only one instance of tight hole was noted while making a bit trip at 8,725 ft. This problem was worked through successfully. Subsequent to drilling the interval to total depth, wireline logs were run without incident. A string of 9 5/8-in. casing was landed at approximately 10,600 ft with no problems.

Solids Removal Efficiency

Although the generation of colloidal solids is minimized, it is not totally eliminated. An added benefit of the HMW polymer is the flocculation of drilled solid particles in the colloidal range. Reduced attrition rates and flocculation of colloidal drilled solids lead to improved SRE, resulting in lower dilution volumes with a corresponding decrease in fluid system product consumption compared to other WBFs.

An SRE study performed as part of this project indicated that the HPWBF provided removal efficiencies of approximately 85%, rivaling those of invert emulsions, typically in the 85-90% range. The study used a variation of the dilution volume formula shown in **Eq. 1** to determine the SRE value. Input data were obtained by taking an average of the low gravity solids (LGS) values from mud reports along with a determination of the volume of drilled cuttings removed from the wellbore and the volumes of commercial product and water additions made during this interval. These values were plugged into the formula shown in **Eq. 2**. The data was then compared to an in-field well in which the intermediate section was drilled with an invert emulsion fluid. The comparison showed the HPWBF system to have an SRE value of approximately 86% while the invert emulsion system was determined to have an SRE value of approximately 89%. Solids removal efficiency directly

affects dilution requirements with higher SREs resulting in lower dilution requirements and a corresponding reduction in material usage.

Dilution Volume Formula

$$V_D = \frac{(1.0 - SRE)(V_R)}{LGS_D} (1.0 - LGS_D) \dots\dots\dots \text{Eq. 1}$$

Where:

- V_D (in bbl)—the volume of dilution fluid needed to maintain a given concentration of LGS
- SRE—the known percent efficiency
- V_R (in bbl)—the volume of cuttings removed from the wellbore
- LGS_D—the percent desired concentration of LGS in the fluid system

Solids Removal Efficiency Formula

$$SRE = 1.0 - \left\{ \frac{(V_D)(LGS_{AVG})}{(1.0 - LGS_{AVG})(V_R)} \right\} \dots\dots\dots \text{Eq. 2}$$

Where:

- V_D (in bbl)—the volume of dilution fluid used in the interval
- SRE—the determined efficiency of all solids control equipment in use
- V_R (in bbl)—the volume of cuttings removed from the wellbore
- LGS_{AVG}—the average percent concentration of LGS in the fluid system

A later dilution requirement study comparing the HPWBF system with a typical dispersed water-based system indicates that the HPWBF requires significantly less dilution to maintain LGS at an acceptable range. This study was conducted on two wells in the same field; interval geometries and depths were also very similar. Results of the study indicate that the HPWBF system required 42% less dilution volume than did the dispersed fluid system.

According to Chilingarian and others,^{4,6} reduced colloidal solids content improves penetration rates due in part to the “chip-hold-down effect.” Solids in the 1- to 2-micron size have a tremendous detrimental effect on ROP.⁷ Solids in this range tend to plug the micro-fractures created by bit cutter impact and impede pressure equalization and the resultant lifting action. With the HPWBF system, there are fewer sub-micron particles to plug the micro-fractures, and as a result, rock chips are more easily removed and carried to the surface.

Non-Dispersed Fluid: Effects on Hydraulics

The non-dispersed nature of the HPWBF system also

helps contribute to increased penetration rates. In a dispersed fluid, commercial products satisfy molecular charges, but as a consequence, total solids surface area increases, as does plastic viscosity. The aggregated or flocculated state of the HPWBF system presents a minimum surface area of clay platelets with a decrease in plastic viscosity and a corresponding increase of energy at the bit. Additionally, these larger agglomerates present fewer sub-micron particles that may impede pressure equalization across the chip and retard penetration rate. **Fig. 2** illustrates the effects of dispersion on relative drilling rate.

Effective Inhibition

The HPWBF system exhibits a large degree of inhibition due in part to the high molecular weight polymer and also to the anionic polymers used to provide fluid-loss control, bentonite extension, and additional inhibition. The anionic polymers adhere to clays in a plating fashion preventing the absorption of water and therefore hydration. The HMW polymer tends to wrap itself around clay particles in a helical fashion, providing reinforcement and lessening the effects of attrition.

The inhibitive nature of this HPWBF system was evaluated against that of a typical dispersed fluid system. To evaluate inhibition, two 12.0-lb/gal fluids were prepared as shown in **Table 1** with the fluid properties listed in **Table 2**. Shale samples were obtained from two Webb County wells, cleaned and pulverized to pass through a 200-mesh (74-micron) sieve. This ground shale was compressed into two pellets that were vacuum desiccated for 72 hr to ensure uniform moisture content (**Table 3** provides pellet data). Linear swell analysis was conducted on the desiccated pellets for 30 hr. Results (**Fig. 3**) indicate significantly less swelling was exhibited by the HPWBF compared to the dispersed fluid.

The inhibitive nature of this HPWBF leads to a more stable, near-gauge wellbore. Drilling a near-gauge wellbore provides several operational benefits, including optimum annular cleaning and cuttings transport, effective logging operations, and economical and effective cementing jobs. Caliper logs of the wells drilled using the HPWBF and invert emulsion fluids were analyzed to determine wellbore enlargement. Based on calculated gauge wellbore volumes and wellbore volumes taken from the caliper logs, the HPWBF well showed an enlargement of 9.6% compared to 7.1% for the invert emulsion. This equates to a difference of less than $\frac{1}{3}$ in. in terms of actual hole diameter. A comparison of caliper logs obtained on wells drilled with the HPWBF and an invert emulsion fluid demonstrates the near-gauge hole results achieved with each system (**Fig. 4**).

Thixotropic Properties

An ideal drilling fluid will exhibit decreased viscosity with increased shear. Viscosity has an indirect effect on the drilling rate in that it affects hydraulics and cuttings removal. Additionally, the less shear-thinning a fluid is, the more likely it is to develop a "viscosity cushion" between bit cutters and formation, resulting in reduced penetration rates.⁴ The low colloidal and polymeric content of the HPWBF results in a highly shear-thinning fluid with less drillstring pressure loss and more energy available at the bit for optimized hydraulic horsepower. This is evidenced by low drillstring and bit pressure losses and high bit hydraulic horsepower values seen on the Eaves No. 5 well. Flow rates averaged 849 gal/min with drillstring pressure losses ranging from 864 psi to 2,400 psi for an average of 1,794 psi drillstring pressure loss. Bit pressure losses averaged 816 psi while bit hydraulic horsepower/in.² averaged 3.43.

HSE Benefits

In regard to health, safety, and environmental concerns, the HPWBF system uses no dispersants or caustic materials. Improved SRE values help conserve water resources and reduce the corresponding waste stream. The HPWBF system has fewer basic components than a comparable dispersed system. The basic components of the HPWBF system comprise about 2% of the volume compared to 4% for a dispersed system. This can help reduce chances for injury while loading and unloading, as well as reducing energy and transport costs. The HPWBF system produces no aromatic wastes.

Cost Comparison to Invert Emulsion Fluids

In addition to providing performance comparable to invert emulsion fluids, the HPWBF helps lower or eliminate costs related to mud and cuttings handling. A study of wells drilled with diesel invert emulsion fluid systems in the Lobo trend of south Texas was conducted in 1999. This study concentrated on the production interval of 15 wells drilled in Webb and Zapata Counties. Of primary concern in this study were ancillary costs associated with diesel-based systems but not necessarily shown as part of the fluid system cost. These ancillary costs included: the mud saver valve, the pipe wiper, cement spacers, oil-base pay for the rig crew, pit cleaning, cuttings disposal, and reserve pit remediation.

The average interval length of the 15 wells was 2,055 ft with an average wellbore diameter of 6 $\frac{1}{4}$ in. Fluid system costs, exclusive of transportation and engineering, averaged \$28,600 (U.S) per interval. Ancillary costs for the 15 wells averaged \$22,000. These two costs together comprise a total fluid system cost of approximately \$50,600 of which 43% is ancillary costs. Ancillary costs are essentially eliminated when wells are

drilled with the HPWBF discussed here.

Conclusions

Low colloidal solids content has a positive effect on ROP. The low colloidal solids content of the HPWBF is illustrated in **Fig. 5**, a particle-size distribution graph of the fluid used on the Eaves No. 5. The HPWBF used on the Eaves No. 5 well exhibited colloidal solids (under 2.0 microns)¹ of less than 10% by volume. The ROP in the 12 ¹/₄-in. interval on this well averaged 63 ft/hr, compared with 69 ft/hr achieved on the offset drilled with a diesel-based fluid in the same interval with the same bit diameter.

Caliper logs of the wells drilled using the HPWBM and invert emulsion fluids were analyzed to determine wellbore enlargement. Based on calculated gauge wellbore volumes and wellbore volumes taken from the caliper logs, the HPWBF well showed an enlargement of 9.7% compared to 7.1% for the invert emulsion.

The use of this HPWBF helped operators eliminate potential risks and ancillary costs associated with using invert emulsion fluids, without compromising drilling performance.

Acknowledgments

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Table 1—Fluid Formulation

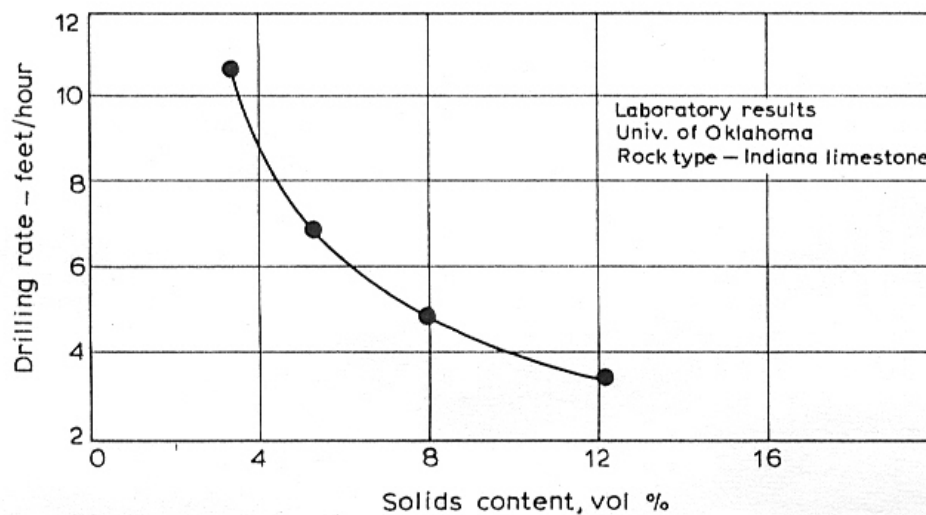
Product, Unit	HPWBF	Dispersed
Water, bbl	0.844	0.809
Premium grade Bentonite, lb	—	20
HPWBF viscosifier, lb	8	—
HPWBF filtration control, lb	4	—
HMW polymer, lb	1.2	—
Caustic soda, lb	—	2
Lignite, lb	—	5
CLS, lb	—	4
Rev Dust, lb	15	20
Barite, lb	182.2	169.3

Table 2—Fluid Properties

Fluid Property	HPWBF	Dispersed
Rolled at 120°F, hr	16	
Stirred, min	15	
Density, lb/gal	12	12
Rheology temperature, °F	120	
Plastic viscosity, cP	28	18
Yield point, lb/100 ft ²	8	6
10-sec Gel, lb/100 ft ²	6	2
10-min Gel, lb/100 ft ²	10	3
pH	8.5	9.6
API filtrate, ml	4.6	3.5
HTHP filtrate at 250°F, ml	15.8	16.6

Table 3—Linear Swell Test Parameters

Test Fluid	HPWBF	Dispersed
Core Length, in.	0.592	0.592
Compaction, psi	10,000	10,000
Compaction, hr	1.5	1.5
Compacted core weight, g	19.95	19.9
Equilibrated core weight, g	19.85	19.85
Weight gain or loss, g	0.1	0.05
Linear swell load, g	550	550

**Fig. 1—Effect of solids content on drilling rate.⁴**

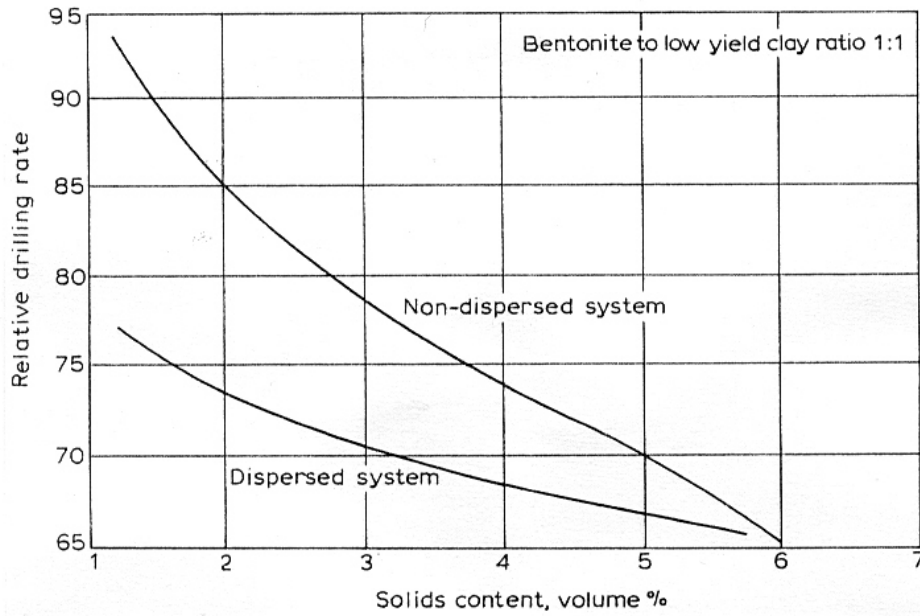


Fig. 2—Effect of dispersion state on relative drilling rate.⁴

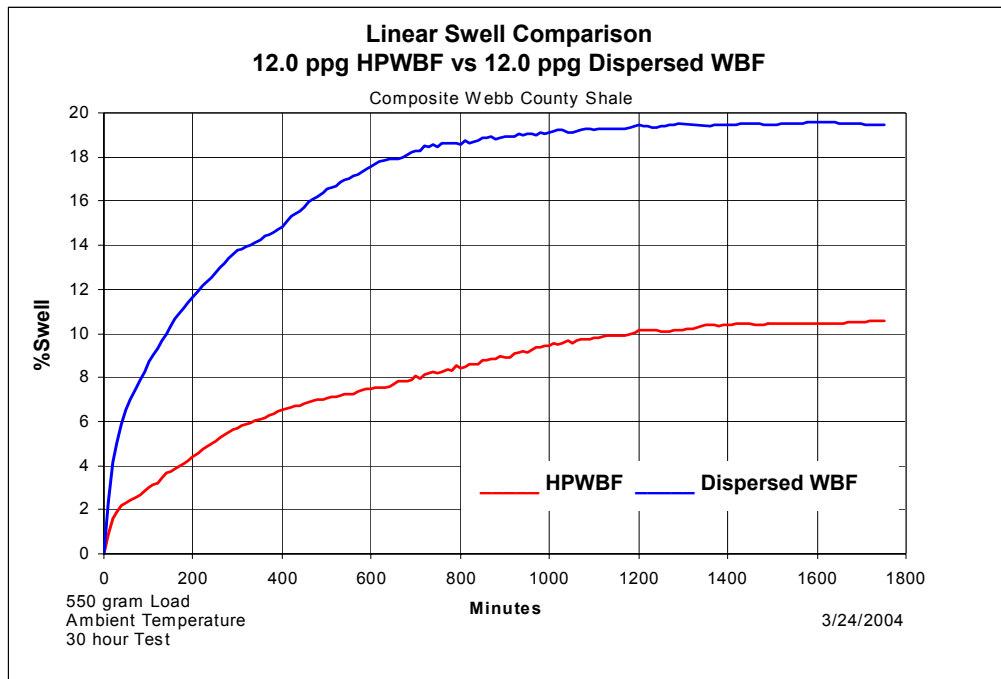


Fig. 3—Linear swell results.

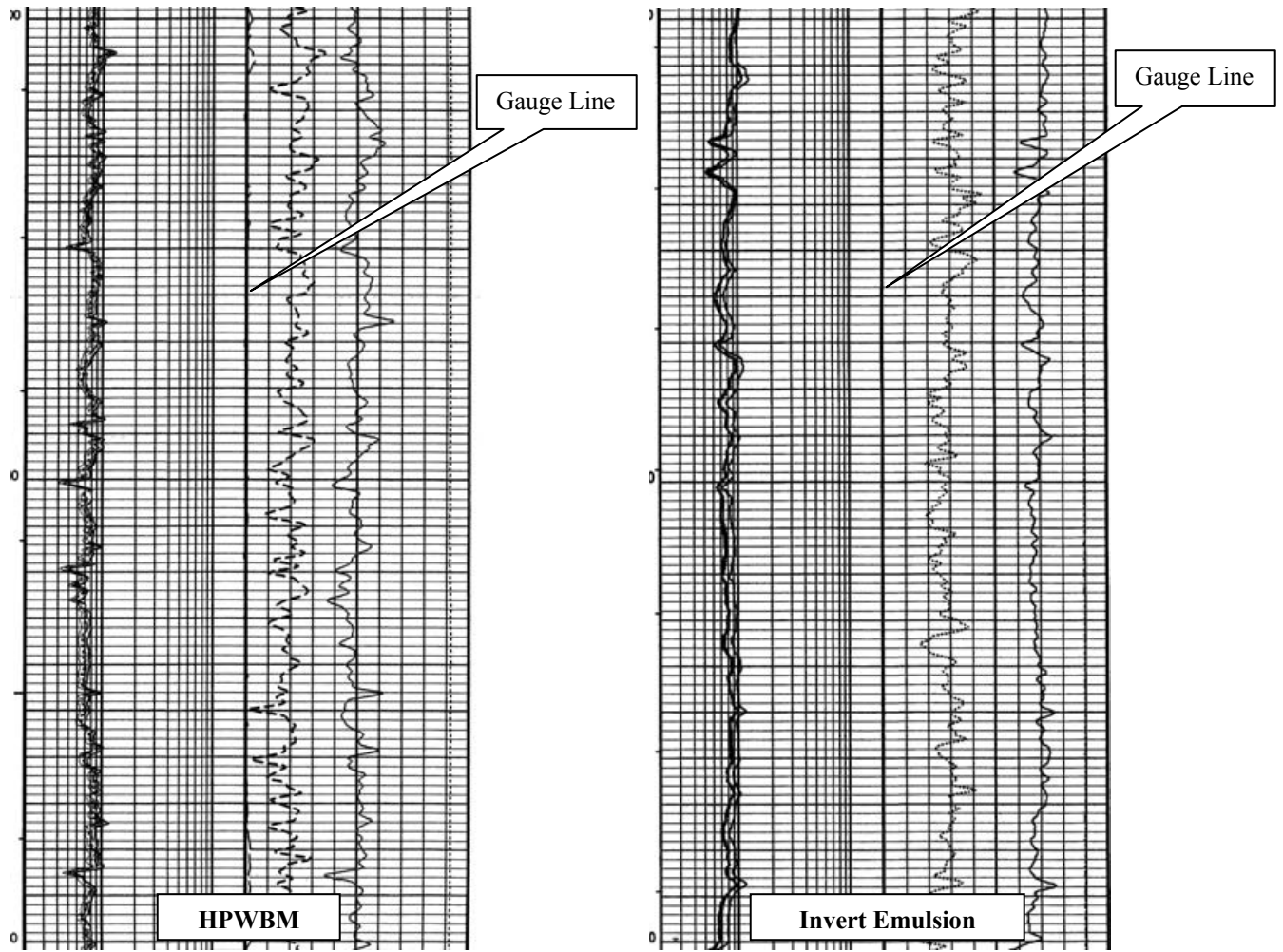


Fig. 4—Typical differential caliper logs.

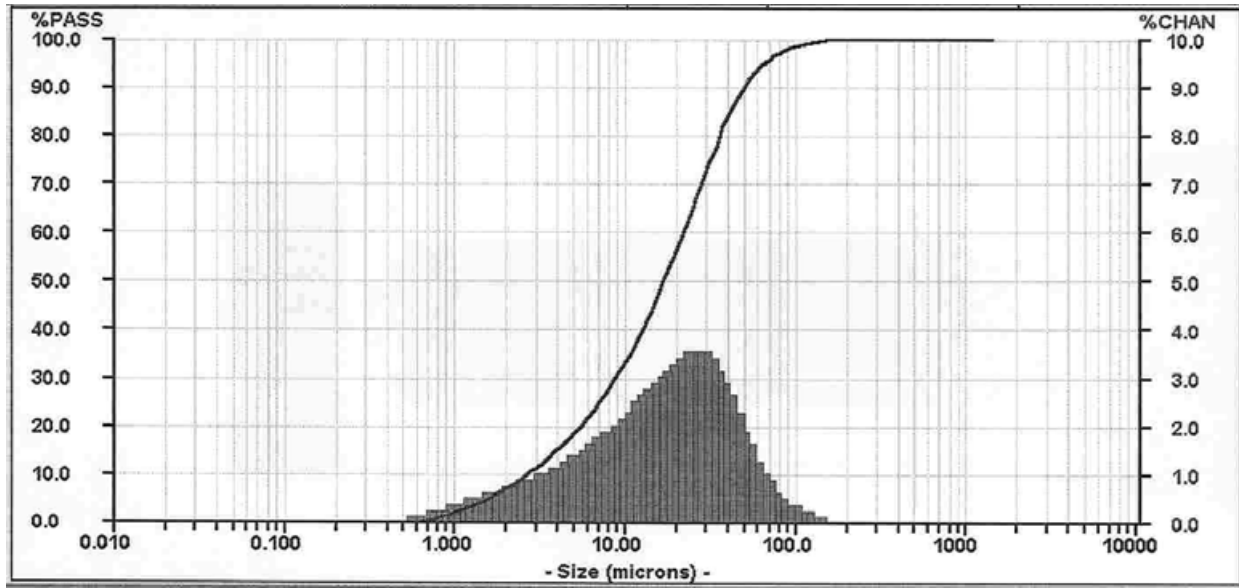


Fig. 5—Particle size distribution.