

Introduction

Drilling fluids are fluids that are used during the drilling of subterranean wells. They provide primary well control of subsurface pressures by a combination of density and any additional pressure acting on the fluid column (annular or surface imposed). They are most often circulated down the drill string, out the bit and back up the annulus to the surface so that drill cuttings are removed from the wellbore.

Drilling fluids have a number of alternative names, acronyms and slang terms used within the industry. The most widely used name is “mud” or “drilling mud” and both these terms will be used interchangeably throughout this chapter. Other drilling fluid names and acronyms are: water-based mud (WBM), oil-based mud (OBM), synthetic-based mud (SBM), non-aqueous fluid (NAF), invert emulsion fluid (IEF), high performance water-based mud (HPWBM), drill-in fluid (DIF) and reservoir drilling fluid (RDF). Similar to drilling fluids are so-called completion fluids that are used to finish the well after drilling is completed. The fluids used during completions are often referred to as workover and completion (WOC) fluids, clear brines and/or packer fluids.

Drilling fluid is a major factor in the success of the drilling program and deserves careful study. Discussion in this manual, however, is limited to its general features. A comprehensive and more academic text on drilling fluids is “Composition and Properties of Drilling and Completion Fluids” by Caenn, Darley and Gray. The suppliers of drilling fluid materials also offer a wide range of publications and numerous articles can be located in the technical literature of the oil and gas industry.

Drilling fluid function and performance

Drilling fluids range from simply water or oil to compressed air and pneumatic fluids to more complex water-based or oil-based systems. Drilling fluid additives include weighting materials; viscosifiers; filtration control additives; pH/alkalinity control chemicals; dispersants/deflocculants/thinners; surfactants and emulsifiers; shale inhibitors; corrosion inhibitors/oxygen scavengers/hydrogen sulfide (H₂S) scavengers; lubricants; and bridging agents/lost circulation materials (LCMs). A brief description of these categories is included later in this section.

The principal functions of drilling fluid are to:

- Control subsurface pressures, maintaining well control;
- Remove drill cuttings from beneath the bit and circulate them to the surface;
- Maintain wellbore stability, mechanically and chemically;
- Transmit hydraulic energy to the drill bit and downhole tools;
- Cool and lubricate the drill string and bit;
- Allow adequate formation evaluation;
- Provide a completed wellbore that will produce hydrocarbons;
- Suspend or minimize the settling of drill cuttings or weight material when circulation is stopped, yet allow the removal of drill cuttings in the surface fluids processing system; and
- Form a low permeability, thin and tough filter cake across permeable formations.



Figure FL-1: Drilling fluids are major factors in a successful drilling program. Courtesy MI-SWACO, a Schlumberger company.

The performance of these functions depends upon the type of formation being drilled and the various properties of the drilling fluid. Often, compromises are necessary due to a variety of factors. The selection and design of a particular drilling fluid and its properties depends on the complexity of the well being drilled, subsurface pressures and temperatures, logistics, cost and local experience. Drilling fluid performance is also affected by the drilling equipment being used.

The properties of the drilling fluid should be adjusted to the hydraulics available for the drilling operation and the well design. Rate of penetration (ROP) and bit life can be improved by optimizing the hydraulic horsepower at the bit, especially for roller cone bits. The ROP and bit life for polycrystalline diamond compact (PDC) cutter bits is improved when an adequate flowrate is used with minimal overbalance. Drilling fluid properties and circulation rates determine the parasitic pressure losses in the drill string and the available pressure at the bit for optimized drilling performance. The ROP is also affected by the density of the mud and nature of the suspended solids. Regular and complete tests are essential to the control of mud properties. The interpretation of the results of these tests and treatments to maintain appropriate fluid properties is vital to the success of the drilling program.

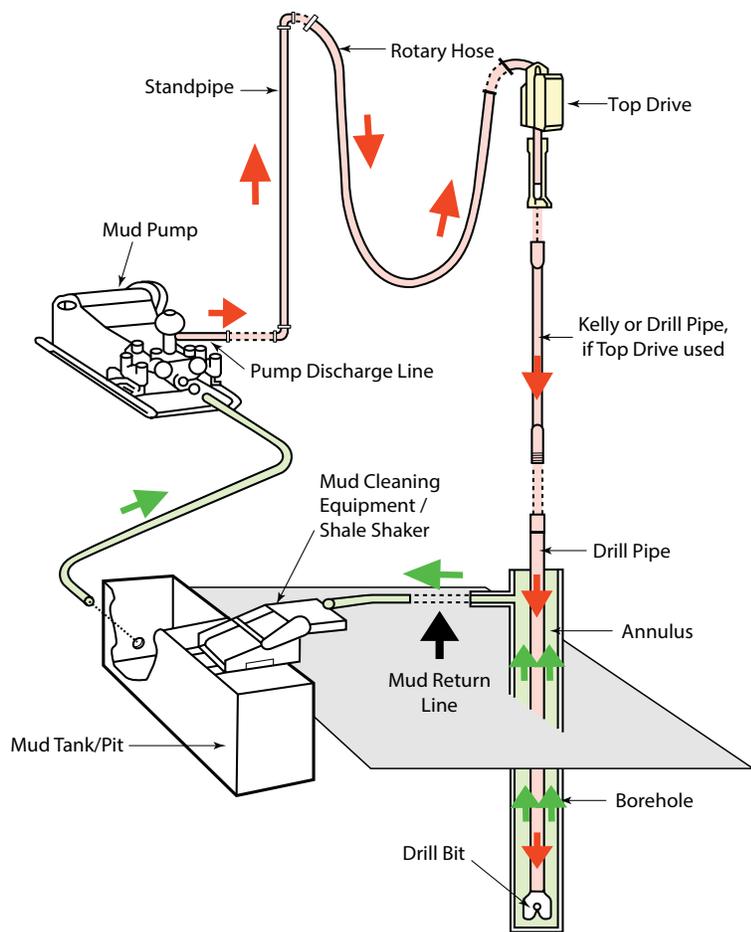


Figure FL-2: Basic land rig circulating system.

Physical operating principles

The three main functions of drilling fluids are to:

- Control subsurface pressures: These pressures are controlled by the hydrostatic pressure of the drilling fluid plus any surface-imposed pressure on the annulus. While circulating, annular pressure losses also impose additional pressure on the wellbore. Hydrostatic pressure is increased by increasing the density of the drilling fluid. This is normally carried out by adding barite (BaSO_4), a high-density inert powder.
- Circulate drill cuttings from the well: This is dependent on a combination of fluid velocity, fluid viscosity, fluid density and drill string rotation.
- Maintain wellbore stability: This is dependent on the strength of the rocks being drilled, local subsurface stresses, differential pressure at the wellbore, drilling fluid chemistry, formation composition, filtration control, filter cake quality and bridging solids.

Testing drilling fluid properties

Various properties of drilling fluid are monitored and adjusted to achieve desired performance. Procedures for measuring fluid properties can be found in API Recommended Practice 13B-1 for water-based drilling fluids and Recommended Practice 13B-2 for oil-based drilling fluids. These procedures are revised and extended periodically as improvements are made and new tests are developed.

Purpose of testing

Routine testing is carried out on drilling fluids to determine the following: the density or mud weight; viscosity; gel strengths, filtration rate (also called fluid loss); sand content; solids, oil and water content; and chemical properties.

Density or mud weight

Density or mud weight is the mass per unit volume. In the field, it is measured with a mud balance and is most often reported in pounds per gallon (lb/gal or ppg); specific gravity or SG (g/ml); kilograms per cubic meter (kg/cu m); or pounds per cubic foot (lb/cu ft). Density is used to determine the hydrostatic pressure of the mud column and can also be measured and expressed as a gradient such as pounds per square inch per thousand feet (psi/1,000 ft). This allows for easy calculation of the hydrostatic pressure at any depth.

The mud scale is calibrated with water (freshwater weighs 8.34 lb/gal and seawater weighs 8.55 lb/gal). The mud scale has four units scales graduated on the beam: lb/gal or ppg, g/cc, lb/cu ft and psi/1,000 ft. Please refer to the section entitled Calculations and Tables for the appropriate calculations and unit conversions.

Viscosity

Viscosity is a measure of the drilling fluids internal resistance to flow, or how thick or thin it is. Drilling fluids are non-Newtonian, meaning that their viscosity is not constant for all shear rates. These non-Newtonian fluids behave very differently than liquids like water or oil which are Newtonian with a constant viscosity regardless of shear rate. Non-Newtonian drilling fluids are shear thinning such that they have lower viscosity at high-shear rates and higher viscosity at low-shear rates. This is desirable for drilling where minimum pressure losses are wanted for the high-shear conditions inside the narrow bore of the drill string. Higher viscosity is wanted in the low-shear conditions of the larger annulus.

Viscosity depends on the viscosity of the base liquid and the

type and concentration of solids in the drilling fluid. Viscosity is usually higher for higher density fluids due to the increased concentration of weight material such as barite. As a general rule, thicker fluids are needed for larger diameter hole sizes and thinner fluids are needed for smaller hole sizes which have smaller annular flow areas.

Viscosity is measured with two primary tools; a) the Marsh funnel (**Figure FL-3**) which is used to frequently measure relative changes in viscosity, and b) a direct reading viscometer (**Figure FL-4**), which is used to measure the viscosity, gel strengths, and non-Newtonian characteristics precisely.

The Marsh funnel is used to monitor relative changes in viscosity and is commonly reported as “funnel viscosity”. The Marsh funnel viscosity is reported as the number of seconds required for a given fluid to flow a volume of 1 qt into a graduated mud cup. Its design and calibration can be verified using water. One quart of fresh water should be collected in 26 (±0.5) sec at a temperature of 70 (±5) °F.

A direct indicating rotational viscometer is used to measure the viscosity at different shear rates to determine the rheology model coefficients. For field operations, the Bingham plastic rheology model coefficients of plastic viscosity (PV) and yield point (YP) are monitored. These two coefficients are used to monitor the non-Newtonian properties of the drilling fluid. These viscometers indicate the shear stress as a “dial unit” or “degree” (Θ) at a given shear rate (one dial unit equals about 1 lb/100 sq ft). The dimensions of the direct indicating viscometer are selected so that the PV and YP can be quickly calculated from the shear stress values measured at shear rates of 600 and 300 rpm. The PV in centipoise (cps) is calculated from the 600-rpm dial reading (Θ_{600}) minus the 300-rpm dial reading (Θ_{300}). The YP in lb/100 sq ft is then calculated from the 300-rpm dial reading minus the PV.

$$PV \text{ (cps)} = \Theta_{600} - \Theta_{300} \quad \text{Eq 1}$$

$$YP \text{ (lb/100 sq ft)} = \Theta_{300} - PV \quad \text{Eq 2}$$

Viscosity should be measured and reported at standard temperatures which are usually 120°F for most wells or 150°F for high-temperature wells. Shear stress values should also be measured at other shear rates for improved accuracy when calculating pressure losses and when cleaning the hole. Typical six speed shear rates are taken at 600, 300, 200, 100, 6 and 3 rpm. The Bingham plastic YP overestimates the real YP for most drilling fluids as well as the shear stress values at lower shear rates. For this reason, using better rheology models such as the Herschel Bulkley model is recommended for improved accuracy.



Figure FL-3: Drilling fluid balance and Marsh funnel are used to measure fluid viscosity.



Figure FL-4: Direct indicating viscometer (6 speed).

The PV depends mainly on the concentration of solids and the viscosity of the base liquid. It is representative of high-shear rate viscosity such as is present inside the bore of the drill string. The YP is a measure of the degree of non-Newtonian shear thinning behavior (increased thickening at low-shear rates is implied from higher YPs). The YP is a result of the attractive forces between particles in the fluid at lower shear rate conditions. It is also a measure of the hole cleaning capabilities of a fluid in vertical intervals. Often, a low-



Figure FL-5: API low-temperature, low-pressure filter press.

shear-rate yield point (LSRYP) is calculated using the shear stress values at 6 rpm and 3 rpm to better evaluate the real YP, the hole cleaning potential and the propensity for having barite sag.

$$\text{LSRYP} = (2 \times \Theta_3) - \Theta_6 \quad \text{Eq 3}$$

Gel strengths

Gel strengths refer to the shear stress required to initiate flow after static periods of time. They are a measure of the degree of gelation that occurs due to the attractive forces between particles over time. Higher gel strengths are reported in the same units as YP (lb/100 sq ft). Sufficient gel strength will suspend drill cuttings and weighting materials during connections and other static conditions. Gel strengths directly affect surge and swabbing pressures when making connections, tripping pipe or running casing. They also affect the pressure required to “break circulation” and the ease of releasing entrained gas or air. Gels are determined using the same direct indicating rotational viscometer as is used for viscosity. They are measured by observing the maximum shear stress value while slowly turning the rotor or by using the 3-rpm setting after being static for some period of time. Standard values for gel strength are taken after 10 sec, 10 min and sometimes after 30 min. The change in gel strength values between these time periods also give

an indication if the fluid is continuing to gel with longer periods of time (called progressive gels) or if it has reached a relatively constant value (called flat gels).

Filtration or fluid loss

Filtration or fluid loss is a relative measure of the liquid that could invade a permeable formation through deposited mud solids. This liquid is called filtrate and the deposited solids are called filter cake or mud cake. There are two standard filtration tests that measure the volume of filtrate collected after a 30-min period of time using filter paper. These tests are the low-temperature/low-pressure fluid loss test, often called the American Petroleum Institute (API) test, and the high-temperature high-pressure (HTHP) test. Results are reported as the milliliters (ml) which flow through a 7.1-sq in. area. The HTHP filtration test unit is a half-area (3.5-sq in.) press; therefore, the measured filtrate value is doubled for reporting. Filter cake thickness is measured and reported in units of $\frac{1}{32}$ in. (or millimeters where SI units are used). A filter cake thickness of 3 means $\frac{3}{32}$ in.

The basic filtration test is called the low-temperature/low-pressure or API fluid loss test and is performed at ambient temperatures and 100 psi. The more advanced test is the HTHP filtration test that is performed at a temperature closer to the bottomhole temperature and at a 500-psi differential pressure. While there is no standard temperature for the HTHP test, temperatures between 275°F and 325°F are often set as the standard. This, of course, is dependent on the area and operator. The HTHP test should preferably be run at the actual bottomhole temperatures and differential pressures existing in the wellbore, if possible.

Filtration rate and filter cake thickness are both monitored and reported properties. High fluid loss and thick filter cakes significantly increase the possibility of having differentially stuck pipe. A desirable filter cake is one that has ultralow permeability and is thin, tough, compressible and slick (lubricious). These desirable properties cannot be determined from the fluid loss values alone and many low fluid loss drilling fluids do not have a good quality filter cake. A desirable filter cake is achieved by minimizing the drill solids content (colloidal-sized solids) of the drilling fluid and maintaining the proper concentration of filtration control additives. For most WBMs, the best quality filter cake is achieved by using an adequate quantity of high-quality bentonite.

There are many factors affecting filtration control including: thermal stability of the system; concentration, size, and type of solids; the type and concentration of filtration control additives being used; and the presence of any contaminants in the mud. Filtration control comes with increased cost. Local experience and the frequency of stuck pipe should be used to establish the target values for fluid loss and filter cake for the formation and hole interval.

Sand content

Sand content refers to the volume percent of whole mud that are “sand sized” particles, meaning they are larger than 74 microns and do not pass through a 200 mesh screen. These may be actual quartz sand or may be the coarse-sized barite particles, sized bridging solids, LCM, drilled solids or any other particles larger than 74 microns. Sand content is measured using a sand content graduated glass tube, funnel and 200 mesh sieve. It is monitored to gauge the effectiveness of solids control equipment, the shale shaker screen condition and the potential for increased abrasion to mud pumps and other equipment in the circulating system including drill string and downhole equipment.

Solids, oil and water content

Solids, oil and water content are measured using a distillation report. With this information and other data from the chemical analysis, a complete breakdown of the composition of the drilling fluid can be made, often called a solids analysis. This will include oil content, water or brine content, low-gravity solids (mainly drill solids) and high-gravity solids (normally barite). Solids content affects drilling rate, flow properties, gel strengths and the overall stability of the mud. Often, the frequency of dilution and chemical treatments are based on the results from this analysis. Optimum solids content and good solids control is essential for overall superior mud performance.

Chemical content

Chemical tests are carried out on the whole mud and filtrate to monitor specifications and to identify contamination. Depending on the type of drilling fluid being used, these tests may include: pH, various measures of alkalinity (P_M , P_F and M_F for WBM and P_{OM} for NAF), lime content, chloride (or salt), calcium (or total hardness), carbonate/bicarbonate, sulfate, methylene blue test (MBT), H_2S , electrical stability, water activity and others. A description of these chemical tests is outside the scope of this document, although the significance of some of these tests is shown in the section entitled System Maintenance and Contamination Treatments.

Importance of the drilling fluid

The performance of the drilling fluid is critical to everyone involved with the operation and to all aspects of the drilling operation. The drilling fluid is the primary means to keep the well from blowing out and it is responsible for keeping the hole in good condition such that drilling operations can continue to the desired depth. Drilling and completion fluids are one of the most important parts of the well construction process and ultimately the performance of the fluid will determine the success or failure of the operation. The responsibility of the proper selection and application of the drilling

fluid is held jointly between the fluids supplier, the drilling contractor and the operator.

General rig personnel involved

The general rig personnel involved with monitoring, operating and maintaining the drilling fluid are the drilling fluids technician (called the mud engineer) and one or more of the drilling crew. The drilling fluids technician is normally employed by the drilling fluids supplier or may be a consultant working for the operator or drilling contractor. The mud engineer performs periodic testing of the drilling fluid properties and recommends the treatments to be made. The derrickman is most often the rigsite worker who monitors mud weight and funnel viscosity, adds chemicals and controls the fluid processing equipment. The driller controls flow of the drilling fluid to the wellbore with the mud pumps. On more complicated operations such as deepwater and offshore operations, the drilling fluid responsibilities described above for the derrickman may be performed by additional rig crew. This is usually someone assigned to monitor the shale shakers, mud pits and/or mixing operations.

Categories of drilling fluids

There are three broad categories of drilling fluids:

- **Pneumatic fluids**, which use compressed air or gas, foam and aerated muds;
- **WBMs**, which use water or brine as the base fluids; and
- **NAFs**, which use oil or other non-aqueous base fluids called OBMs or SBMs.

Within each of these three broad categories, there are numerous variations in fluid properties and products that may be used dependent on the practices in an area and the drilling fluids supplier. Numerous common names, acronyms, abbreviations and trade names can describe the particular system being used.

The selection of the drilling fluid system for a particular well is based on numerous factors including: local practices; operator preferences; supplier’s range of systems and products; density required to control subsurface pressures; hole size; characteristics of the formations to be drilled (including wellbore stability); anticipated temperature and pressure; completion type; common regional drilling problems; logistics; cost and quality; and health, safety and environmental (HSE) considerations.

Wells are spudded with simple low-density drilling fluids and altered with each interval to address the conditions of the particular interval being drilled. Generally, the density and complexity of the drilling fluid system being used increases with depth due to increased pressures and tem-