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Course outline –Applied Petroleum Geology

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Types of well data

1. **Mud Logging**
2. **Coring/Core data**
3. **Wireline Logging**

Mud logging

Mud logging involves the rig-site monitoring and assessment of information that comes to the surface while drilling, with the exclusion of data from downhole sensors.

The term mud logging is thought, by some, to be outdated and not sufficiently descriptive. Because of the relatively broad range of services performed by the geologists, engineers, and technicians traditionally called mud loggers, the term "surface logging" is sometimes used, and the personnel performing the services may be called surface-logging specialists. Additional specialist designations may include;

- Pore pressure engineer
- Formation evaluation engineer
- Logging geologist
- Logging engineer

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Objectives/Functions

There are several broad objectives targeted by mud logging: identify potentially productive hydrocarbon-bearing formations, identify marker or correlatable geological formations, and provide data to the driller that enables safe and economically optimized operations. The actions performed to accomplish these objectives include the following:

- Collecting drill cuttings.
- Describing the cuttings (type of minerals present).
- Interpreting the described cuttings (lithology).
- Estimating properties such as porosity and permeability of the drilled formation.
- Maintaining and monitoring drilling-related and safety-related sensing equipment.
- Estimating the pore pressure of the drilled formation.
- Collecting, monitoring, and evaluating hydrocarbons released from the drilled formations.
- Assessing the producibility of hydrocarbon-bearing formations.
- Maintaining a record of drilling parameters.

The traditional products delivered by a mud-logging vendor include:

- Geological evaluation
- Petrophysical/reservoir formation evaluation
- Drilling engineering support services

In this overview, we consider that these products support three basic processes associated with drilling and evaluation of wells:

- Formation evaluation (building or refining the geological and reservoir models)
- Drilling engineering and operations (the planning and execution of the well construction process)
- Maintaining drilling and evaluation operations with appropriate health, safety, and environmental (HSE) consideration

Drilling muds/fluids

There are several different types of drilling fluids, based on both their composition and use. The three key factors that drive decisions about the type of drilling fluid selected for a specific well are:

- Cost
- Technical performance
- Environmental impact.

Selecting the correct type of fluid for the specific conditions is an important part of successful drilling operations.

Classification of drilling fluids

1. Water based
2. Oil based
3. Emulsion

1. **Water based**:

Water-based fluids (WBFs) are used to drill approximately **80%** of all wells. The base fluid may be fresh water, seawater, brine, saturated brine, or a formate brine. The type of fluid selected depends on anticipated well conditions or on the specific interval of the well being drilled.

For example, the surface interval typically is drilled with a low-density water- or seawater-based mud that contains few commercial additives. These systems incorporate natural clays in the course of the drilling operation.

Some commercial **bentonite or attapulgite** also may be added to aid in fluid-loss control and to enhance hole-cleaning effectiveness. After surface casing is set and cemented, the operator often continues drilling with a WBF unless well conditions require displacing to an oil- or synthetic-based system.

Water-based fluids (WBFs) are the most widely used systems, and are considered **less expensive** than oil-based fluids (OBFs) or synthetic-based fluids (SBFs). The OBFs and SBFs—also known **as invert-emulsion** systems—have an oil or synthetic base fluid as the continuous(or external) phase, and brine as the internal phase. Invert-emulsion systems have **a higher cost per unit** than most water-based fluids, so they often are selected when well conditions call for reliable shale inhibition and/or excellent lubricity. Water-based systems and invert-emulsion systems can be formulated to tolerate relatively high downhole temperatures. Pneumatic systems most commonly are implemented in areas where formation pressures are relatively low and the risk of lost circulation or formation damage is relatively high. The use of these systems requires specialized pressure-management equipment to help prevent the development of hazardous conditions when hydrocarbons are encountered.

WBFs fall into two broad categories: **nondispersed** and **dispersed.**

1.1 Dispersed muds

These muds have a chemical dispersant added to the system which is used to deflocculate mud solids. Most of the chemical dispersants in use (such as lignite and lignosulfonate) are acidic and require an alkaline environment in which to function properly. Of all the water-based muds, high pH muds are the most tolerant of solids and contamination. They are, without a doubt, the least difficult of the water muds to maintain. Clay (bentonite) is used as a viscosifier and fluid loss agent. Dispersants are use to permit enough clay into the system to control fluid losses. Caustic soda (NaOH) is used for pH control, and the density is adjusted with weight materials.

Dispersed muds can be broken into two smaller categories: ***calcium-based*** and ***seawater muds***,

- *Calcium-Based Mud*—Calcium-based mud systems maintain a desired amount of calcium in the water phase. The calcium concentration can be maintained by using gypsum ($CaSO_4$) or lime [$Ca(OH)_2$]. These muds are more inhibitive and can tolerate cement and anhydrite contamination better than a freshwater-dispersed fluid. However, their thermal limitation is somewhat reduced.

- *Seawater Mud*—in seawater muds, the upper limit for conventional dispersed fluids to function efficiently is 20,000 mg/L chlorides (which is the salinity of seawater). The cost for this type of system is slightly higher than that of a freshwater system. However, in offshore environments, this cost is offset by allowing muds to be run using native seawater rather than transporting in freshwater

1.2 **Nondispersed muds**

A basic difference between dispersed and nondispersed muds is the lack of dispersants. Nondispersed drilling muds do not require an elevated pH. By not having a dispersant present, they are less tolerant of solids and contamination.

The majority of the fluid loss control and viscosity is maintained via polymers, and these products are very susceptible to contamination from the formation, produced gases, and fluids.

2. Oil-based fluids

Oil-based systems were developed and introduced in the 1960s to help address several drilling problems:

- Formation clays that react, swell, or slough after exposure to WBFs
- Increasing downhole temperatures
- Contaminants
- Stuck pipe and torque and drag

Oil-based muds were developed to prevent water from entering the pore spaces and causing formation damage. There are several advantages and disadvantages of this type of mud system. The advantages include the following:

- *Shale inhibition*—in highly smectitic or “gumbo” shales, the borehole maintains stability and cuttings samples are generally intact.

- *Reduction of torque and drag problems*—since oil is the continuous phase, the borehole and the tubulars are wetted with a lubricating fluid. This is a distinct advantage in deviated wellbores.
- *Thermal stability*—Oil-based muds have shown stability in wells, with BHTs of 585°F
- *Resistance to chemical contamination*—Carbonate, evaporite, and salt formations do not adversely affect the properties of an oil mud. CO_2 and H_2S can easily be removed with the addition of lime ($CaCO_3$).

Disadvantages of oil-based mud systems include the following:

- *High initial cost*—the oil fraction alone of a barrel of oil mud may cost 40-70 USD per barrel. This is considerably higher than most water-based muds at any weight.
- *Slow rates of penetration*—Oil muds historically have had lower rates of penetration as compared to water-based muds.
- *Pollution control*—most areas where oil muds are used have environmental restrictions. Rig modifications may be necessary to contain possible spills, to clean up oil mud cuttings, and to handle whole mud without dumping.
- *Disposal*—Oil mud cuttings may have to be cleaned up before dumping. Some regulatory agencies require cuttings be sent to a designated disposal area.
- *Kick detection*—H_2S, CO_2 and CH_4 are soluble in oil muds. If gas enters the wellbore, it can go into solution under pressure. As the gas moves up the wellbore, it can break out of solution at the bubble point and rapidly evacuate the hole, blowing the mud with it.
- *Formation evaluation*—some wireline logs should not be run in oil-based muds. Also, additional steps are needed to remove oil coatings from cuttings before they are described. (For more information on wireline tool compatibility with drilling fluid composition, see Basic tool table, and for more on removing oil coatings from cuttings, see Mudlogging: drill cuttings analysis.)

Oil-based muds contain three phases: *oil*, *brine,* and *solids phase.*

Oil phase

The oil phase is the continuous phase in which everything else in the system is mixed. The oil can be diesel, mineral oil, or one of the new types of synthetic oils.

Brine phase

The brine phase is present in the system as a high concentration salt solution that is emulsified into the base oil. Usually a solution of calcium chloride is used because it gives a greater flexibility in adjusting the concentration of the salts. This phase is difficult to control because, if the salt concentration nears saturation, the emulsifiers and oil-wetting compounds precipitate.

Solids phase

The solids phase includes the weight material, viscosifiers, and fluid loss reducers. A primary requirement for this phase is that it remain oil wet. Compounds exclusively developed for this purpose are included in the oil mud make-up. If the solid phase ever becomes water wet, the system is said to have “flipped” and the consequences are severe and operationally expensive. The system will separate into two phases: solid and liquid. The solid phase will pack and plug the wellbore, necessitating remedial drilling.

3. **Emulsion/Synthetic**

Synthetic-based fluids were developed out of an increasing desire to reduce the environmental impact of offshore drilling operations, but without sacrificing the cost-effectiveness of oil-based systems.

Like traditional OBFs, SBFs can be used to:

- Maximize rate of penetrations (ROPs)
- Increase lubricity in directional and horizontal wells
- Minimize wellbore-stability problems, such as those caused by reactive shales

Field data gathered since the early 1990s confirm that SBFs provide exceptional drilling performance, easily equaling that of diesel- and mineral-oil-based fluids.

In many offshore areas, regulations that prohibit the discharge of cuttings drilled with OBFs do not apply to some of the synthetic-based systems. SBFs’ cost per barrel can be higher, but they have proved economical in many offshore applications for the same reasons that traditional OBFs have: fast penetration rates and less mud-related nonproductive time (NPT). SBFs that are formulated with linear alphaolefins (LAO) and isomerized olefins (IO) exhibit the lower kinematic viscosities that are required in response to the increasing importance of viscosity issues as operators move into deeper waters. Early ester-based systems exhibited high kinematic viscosity, a condition that is magnified in the cold temperatures encountered in deepwater risers.

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Functions of Drill mud/fluid

1) **To remove cuttings from the bottom of the hole and carry these to the surface**
2) **To cool and lubricate the drilling bit and help smooth cutting**
3) **To wall the hole with impermeable cake which will resist cave in.**
4) **To control subsurface pressure**
5) **To hold the cuttings in suspension when circulation is stopped.**
6) **To support part of the weight of drilling pipe and casing.**
7) **Transport cuttings and gas to the surface**
8) **Add buoyancy to the drill string**

Properties of fluids

Density

The correct drilling fluid density is dependent on the subsurface formation pressures. Strong, competent formations can be drilled with a density less than 1.0, but overpressured shales and high pressure formations may require a fluid with specific gravities approaching 2.4. The density can be adjusted with soluble salts or by addition of solids, termed weight material (for example, barite is added to the mud to increase the density). Density values can be expressed as one of the following:

- ppg = pounds per gallon (United States)
- S.G. = specific gravity (dimensionless) (international)
- psi/ft = pounds per square inch per foot (uncommon)
- pcf = pounds per cubic foot (California)

Viscosity

The flow properties of the mud depend on the depth of the hole and the annular viscosities. In the upper hole, water may be sufficient, but at greater depths more viscous fluids may be required. Deep wells, directional wells, high penetration rates, high mud weights, and high temperature gradients create conditions requiring close attention to the flow properties. The viscosity can be adjusted upward with polymers or clay material or adjusted downward with chemical thinners or water.

Fluid loss control

The fluid loss gives a relative indication of how the mud is controlling loss of the base fluid into the formation. This becomes important when porous formations, particularly those containing oil or gas, are drilled. In porous formations, the drilling fluid may penetrate the rock and cause formation damage. (However, a low fluid loss does not always ensure minimal formation damage.) There are many types of fluid loss additives, such as bentonite, that can be used in the mud to help mitigate this problem.

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Chemical composition

Drilling fluids are two-phase compounds: a fluid and solid phase. The character of the fluid phase is determined by chemically analyzing the concentrations of calcium, chlorides, hydroxols, bicarbonate and carbonate ions, sodium, potassium, and nitrates. The character of the solid phase is tested to determine solids concentration, specific densities, and particle sizes. The primary means of controlling solids are by removal via shale shakers, desanders, desilters, and/or dilution.

Air drilling

Under a restricted set of conditions, air can be used as the drilling fluid when drilling through formations having little or no permeability to water. Although classified as “air” drilling, several types of gasses are actually used.

Dry air

Air is compressed and pumped down the drill pipe at 500–800 ft^3/min (cfm). The returned air is blown out the “blooie” line to a pit designed to retain the dust and cuttings. Dry air is preferred for fast drilling in dry, hard rock conditions with no water influx.

Mist

Mist drilling follows the same format as dry air drilling, but brine water is injected into the air stream. This is the method of choice when drilling wet formations with minimal water influx. The brine mist is injected to minimize reaction of the formation with a freshwater influx.

Foam

Foam drilling follows the same format as mist drilling, but with a foaming agent introduced into the mist stream. Foam is preferred when drilling stable formations that may have a moderate influx of water