MÁSTER EN INGENIERÍA DE PETRÓLEO Y GAS
OIL & GAS ENGINEERING MASTER'S DEGREE

MODULE DE3:
DRILLING ENGINEERING

COURSE DE3.2
DRILLING FLUIDS AND HYDRAULICS

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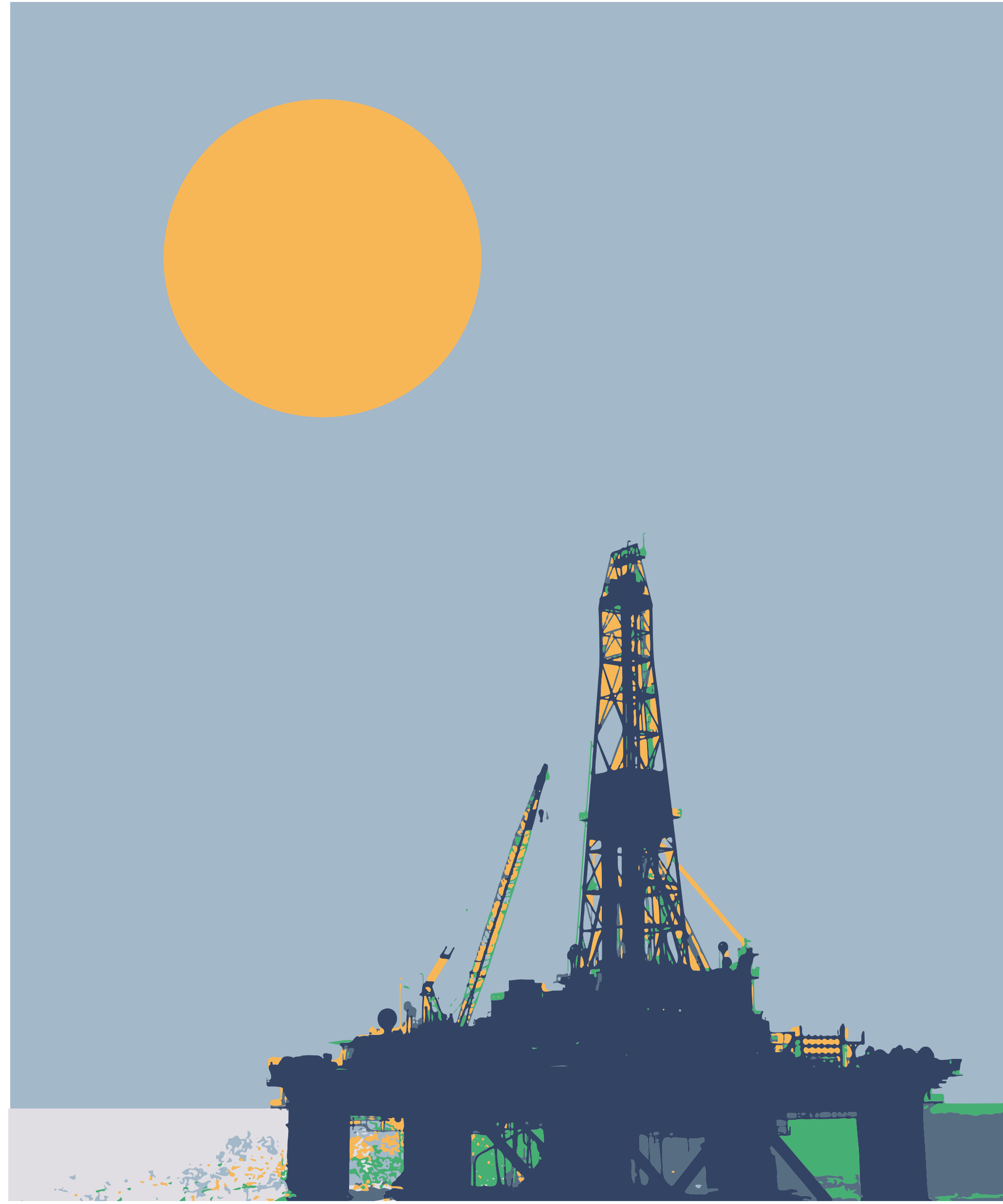

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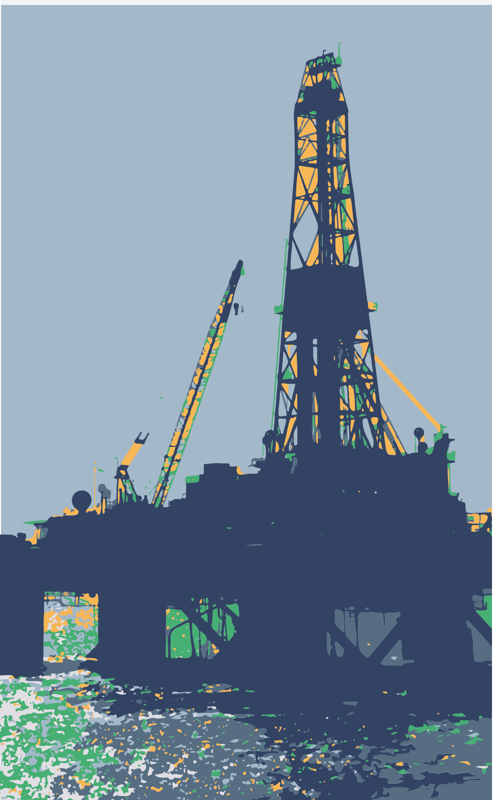

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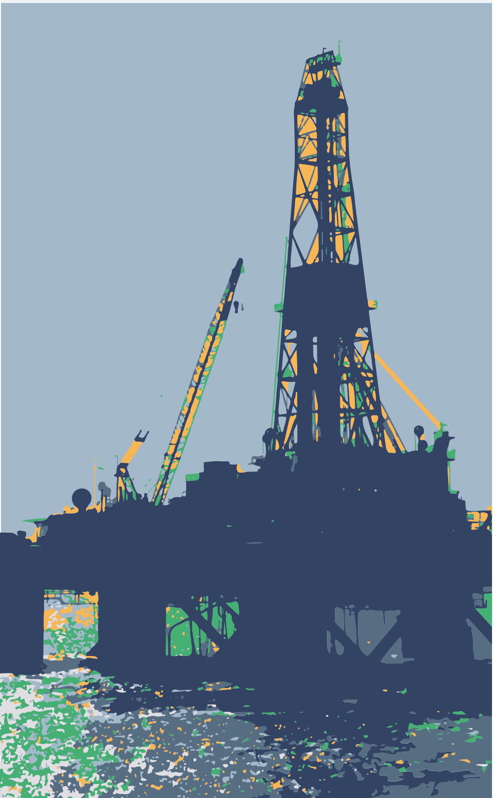
Drilling 101

https://youtu.be/yz46jaMEVCY

https://www.youtube.com/watch?v=qB9UwRInxY0

https://energyinformationaustralia.com.au/oil-and-gas-explained/



1.
Introduction to drilling fluids.

The function of the drilling fluids

- Initially, the primary purpose of drilling fluids was to clean, cool and lubricate the bit and continuously remove cuttings from the borehole.
- With the progress,
  - More sophisticated functions were demanded from the drilling fluids (mud).
  - Many additives for any conceivable purpose were introduced.

- As a result, what started out as a simple fluid has become **a complicated mixture of liquids, solids and chemicals** for which **"mud engineers"** are contracted by the operating company.

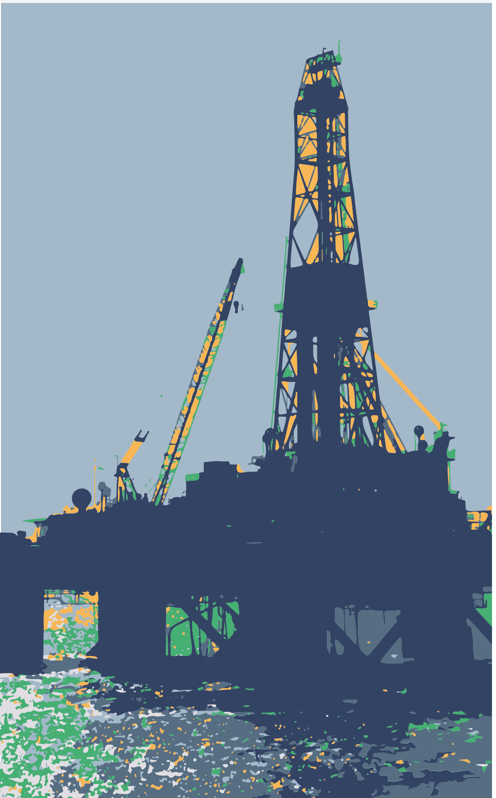
- The drilling-fluid is the single component of the well-construction process that remains in contact with the wellbore throughout the entire drilling operation.
- Drilling-fluid systems are designed and formulated to perform efficiently under expected wellbore conditions.
- Advances in drilling-fluid technology have made it possible to implement a cost-effective, fit-for-purpose system for each interval in the well-construction process.

- Today, the drilling fluid must permit the securing of all information necessary for evaluating the productive possibilities of the formations penetrated.

- The fluid's characteristics must be such that good cores, wireline logs and drill returns logs can be obtained.

- Drilling fluids must be studied from the standpoint of:
  - Technology
  - Chemistry
  - Mud Conditioning Equipment

- **Three key factors usually determine the type of fluid selected for a specific well:**
  - **Cost**
  - **Technical performance**
  - **Environmental impact**



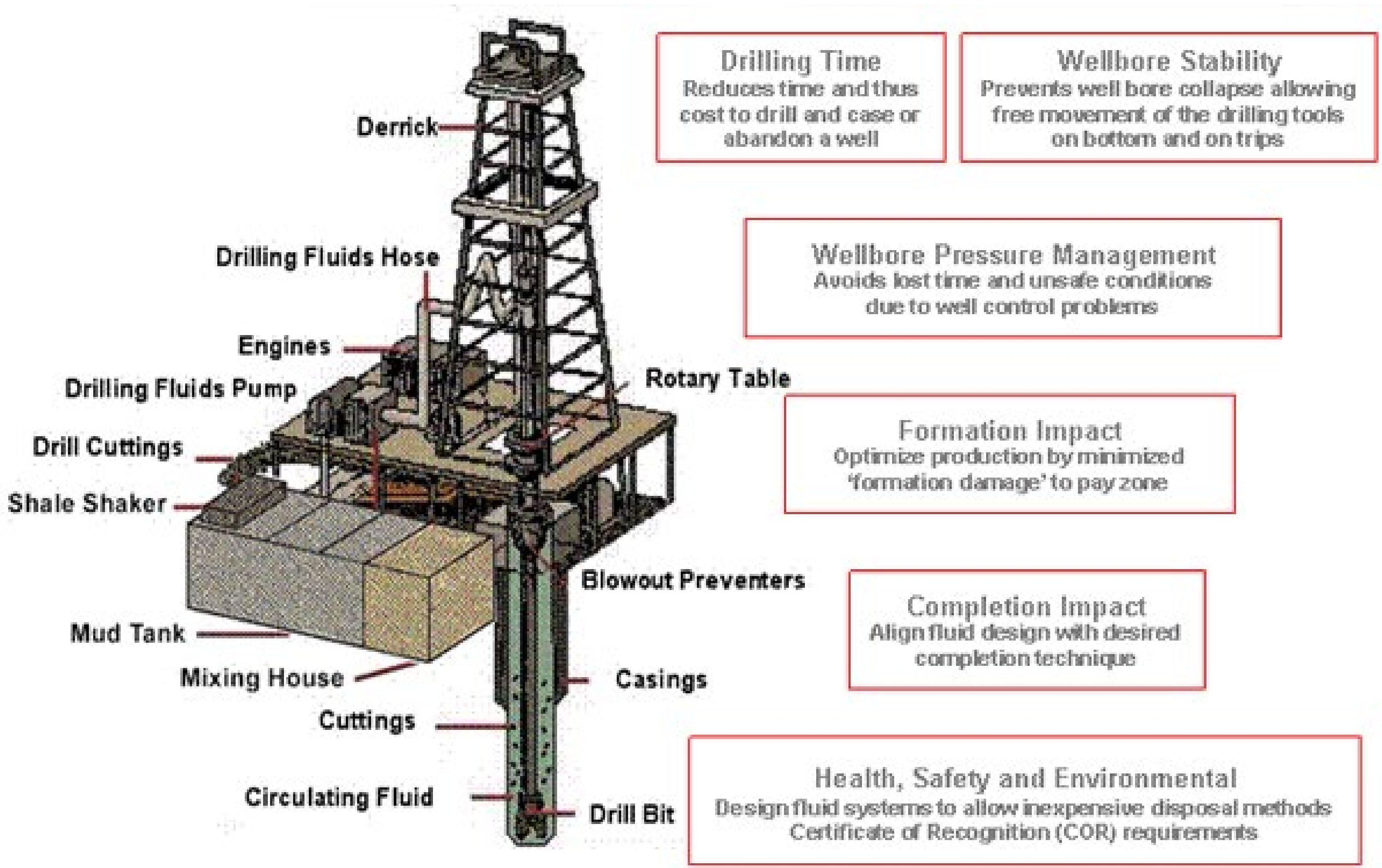
2.
Basic Functions of the Drilling Fluids.

Drilling fluids

- The drilling fluid is a mix of different components:
    - Base (water in the vast majority of occasions)
    - Mud and mineral additives
    - Chemical Additives

- **Basic functions of the drilling fluids:**
    1. To provide hydraulic power to the drilling string
    2. To transport the crushed rock chips outside of the well
    3. To support the walls of the drilled well
    4. To prevent the entrance of formation fluids into the drilled well
    5. To help to the heat dissipation and to lubricate the bit and the drilling string

- **Main fluid types:**
    1. Water/Clay muds
    2. Oil/Clay muds
    3. Compressed gases


Derrick
Drilling Fluids Hose
Engines
Drilling Fluids Pump
Drill Cuttings
Shale Shaker
Mud Tank
Mixing House
Cuttings
Circulating Fluid
Rotary Table
Blowout Preventers
Casings
Drill Bit
Drilling Time
Reduces time and thus cost to drill and case or abandon a well
Wellbore Stability
Prevents well bore collapse allowing free movement of the drilling tools on bottom and on trips
Wellbore Pressure Management
Avoids lost time and unsafe conditions due to well control problems
Formation Impact
Optimize production by minimized 'formation damage' to pay zone
Completion Impact
Align fluid design with desired completion technique
Health, Safety and Environmental
Design fluid systems to allow inexpensive disposal methods
Certificate of Recognition (COR) requirements

- The cost of the drilling fluid averages around the 10% of the total tangible costs of well construction.

- However, **drilling-fluid performance can affect overall well-construction costs in several ways.**

- A correctly formulated and well-maintained drilling system can contribute to cost containment throughout the drilling operation by:
  - Enhancing the rate of penetration (ROP)
  - Protecting the reservoir from unnecessary damage
  - Minimizing the potential for loss of circulation
  - Stabilizing the wellbore during static intervals
  - Helping the operator remain in compliance with environmental and safety regulations.

- To the extent possible, the drilling-fluid system should help preserve the productive potential of the hydrocarbon-bearing zone(s).

- Minimizing fluid and solids invasion into the zones of interest is critical to achieving desired productivity rates.

- The drilling fluid also should comply with established health, safety, and environmental (HSE) requirements so that personnel are not endangered and environmentally sensitive areas are protected from contamination.

- Drilling-fluid companies work closely with oil-and-gas operating companies to attain these mutual goals.

Drilling Fluid Technology

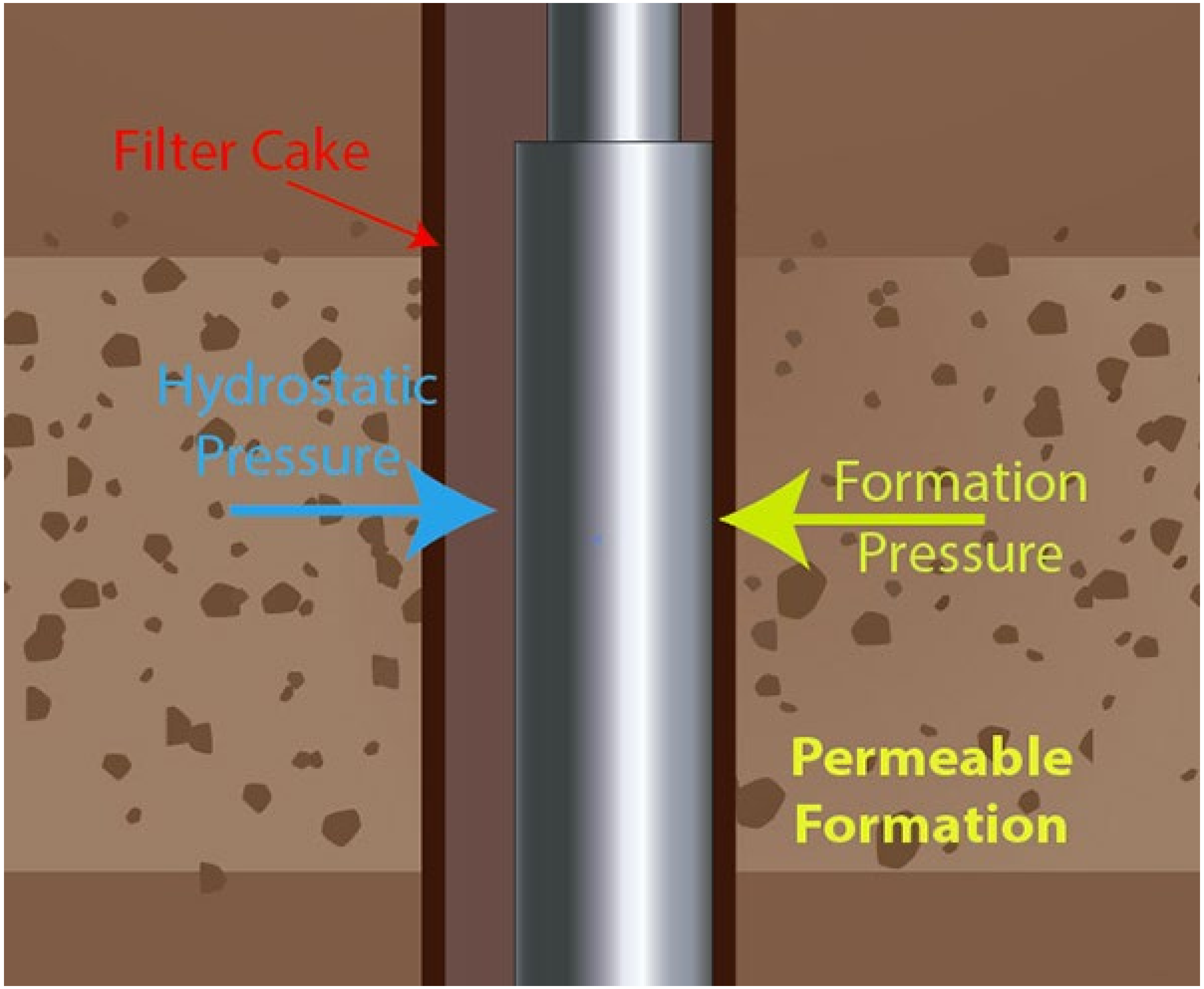
- Numerous types of mud are available due to the varied hole conditions.

- Factors such as depth, types of formations, local structural conditions, etc., all enter into the choice of a particular mud.

- The functions and corresponding properties of a drilling mud are to:
  - **Control subsurface pressures and prevent caving (mud density)**
  - **Remove cuttings from the borehole (viscosity)**
  - **Suspend cuttings when circulation stops (gel strength)**
  - **Cool and lubricate the bit and drill string (additive content)**
  - **Wall the borehole with an impermeable filter cake (water loss)**
  - **Release the cuttings at the surface (viscosity/gel strength)**
  - **Help support the weight of the drill string/casing (density)**
  - **Ensure maximum information from the producing formation to be retrieved through cuttings analysis, logging-while-drilling data, and wireline logs.**
  - **Do all of the above, without damage to the circulation system**

Control of Subsurface Pressures and Prevent Well-Control Issues:

1. The pressure of the mud column at the bottom of the borehole is a function of the mud density and column height.
2. Under normal drilling conditions, this pressure should balance or exceed the natural formation pressure to help prevent an influx of gas or other formation fluids.
3. As the formation pressures increases, the density of the drilling fluid is increased to help maintain a safe margin and prevent “kicks” or “blowouts”.
4. The drilling fluid pressure must be adequate at all times to prevent the flow of formation fluids into the borehole:
    - If mud density falls below that which is necessary to hold back formation pressures, then formation fluids can enter the well.
        - This is termed a "kick".
        - If this condition is allowed to continue unchecked for even a short period of time, the mud density may be reduced (cut) so severely that uncontrolled flow will result. This is termed a "blowout".
    - On the other hand, excessive mud weights results in:
        - Low rates of penetration and
        - The fracturing of weak formations and may cause the loss of drilling mud into them (lost circulation).


Filter Cake
Hydrostatic Pressure
Formation Pressure
Permeable Formation

5. Density is also important in preventing unconsolidated formations from caving into the borehole.
    - However, if the density of the fluid becomes too heavy, the formation can break down.
    - If drilling fluid is lost in the resultant fractures, a reduction of hydrostatic pressure occurs.
    - This pressure reduction also can lead to an influx from a pressured formation.
    - Therefore, maintaining the appropriate fluid density for the wellbore pressure regime is critical to safety and wellbore stability.

6. Effects of mud weight on drill returns logging:
   - Hydrostatic pressure in excess of formation pressure:
     - Will cause formation fluids to be flushed back into the formation being penetrated, either at the bit or just ahead of it.
     - This flushing occurs at all times, whether marginally or greatly overbalanced.
     - If circulation is lost, then the cuttings, drilling mud and any formation fluids they may contain are also lost.
     - The way in which a loss circulation zone behaves generally indicates the type of porosity of the formation into which the fluid is being lost. Examples are:
       a. Coarse, permeable unconsolidated formations: There is normally some loss by filtration into these formations, until an impermeable filter cake is formed. If pore openings are large enough, then loss of whole mud occurs. Other than in extreme cases, this is a slow, regular seepage loss. Partial returns are maintained.
       b. Cavernous and vugular formations: Loss is usually sudden and of a finite amount, after which full returns are maintained.
       c. Fissured or fractured formations: Fractures may be natural or induced and opened by the hydrostatic pressure. Losses of drilling mud are large and continuous.

- Formation pressures that approximate or are greater than the hydrostatic pressure:
  - May allow entry of formation fluids, depending on permeability.
  - In low permeability formations (shales), cavings may occur, making cuttings analysis difficult.

Hydrostatic Pressure:
It is the pressure which exists due to the drilling fluid weight and vertical depth of the column of fluid.

Hp = C x MD x TVD

where:
C = Conversion constant
MD = Mud Density
TVD = True Vertical Depth

If:
Hp =psi
MD = lbs/gal or ppg
TVD = feet
C = 0,0519
Hp = bars
MD = g/cc
TVD = meters
C = 0,0981

Removing and Suspending the Cuttings:

1. The drilling mud must carry the cuttings up the borehole and suspend them when circulation is stopped. To accomplish this:
   - The fluid should have adequate suspension properties to help ensure that cuttings and commercially added solids such as barite weighing material do not settle during static intervals.
   - The fluid should have the correct chemical properties to help prevent or minimize the dispersion of drilled solids, so that these can be removed efficiently at the surface.
   - Otherwise, these solids can disintegrate into ultrafine particles that can damage the producing zone and impede drilling efficiency.

2. The most important factors involved are:
   - The speed at which the mud travels up the borehole (annular velocity),
   - The viscosity and
   - The gel strength of the drilling mud.

3. Viscosity:
    - Applied to drilling fluids, **it is the resistance that the drilling fluid offers to flow when pumped**.
    - It **affects the ability of the drilling fluid to lift the rock cuttings** out of the borehole.
    - It is dependent on the amount and character of the suspended solids.
    - Viscosity is ordinarily measured in the field using a "Marsh Funnel“:
        - The funnel is filled with one quart of drilling fluid, and the elapsed time to empty the funnel is recorded in seconds.
        - The measurement of "funnel viscosity" is "sec/qt" (seconds per quart).
        - This value can range from 20 to 80, but is normally maintained between 40 and 50.

4. Gel Strength:
   - This property refers to the ability of the drilling fluid to develop a gel as soon as it stops moving.
   - Its purpose is to suspend the cuttings and mud solids (weight material), while they are in the borehole and do not permit them to settle around the bit when circulation is halted.
   - In general, gel strength should be low enough to:
     - **Allow the cuttings to be removed at the surface**
     - **Permit entrained gas to be removed at the surface**
     - **Minimize swabbing when the pipe is pulled from the borehole**
     - **Permit starting of circulation without high pump pressures**

   - The gel strength is most commonly determined with a "Fann VG (Viscosity/Gel) Meter" and is expressed in $lbs/100ft^2$ (pounds per 100 square feet).
   - Drilling muds ordinarily have gel strengths between 5 and 30 $lbs/100ft^2$.

5. **Effects of viscosity** and gel strength on drill returns logging when the viscosity or gel strength (or both) is too high:

- The **drilling fluid tends to retain any entrained gas** as it passes through the surface mud cleaning equipment, with the effect that the gas may be recycled (reintroduced in the borehole) several times.
- **Swabbing of the borehole may also introduce extraneous gas anomalies**.
- **Fine cuttings** may be held in suspension so if they **cannot be removed** at the shale shakers and settling pits, thus recycling and contaminating the cuttings samples.
- Cuttings consisting of **clays or other dispersible material may be dissolved**.

<u>Preserve Wellbore Stability.</u>

- Maintaining the optimal drilling-fluid density not only helps contain formation pressures, but also helps **prevent hole collapse and shale destabilization**.

- The wellbore should be free of obstructions and tight spots, so that the drillstring can be moved freely in and out of the hole (tripping).

- **After a hole section has been drilled to the planned depth, the wellbore should remain stable under static conditions while casing is run to bottom and cemented.**

- The drilling-fluid program should indicate the density and physicochemical properties most likely to provide the best results for a given interval.

Minimize Formation Damage.

- Drilling operations expose the producing formation to the drilling fluid and any solids and chemicals contained in that fluid.

- **Some invasion of fluid filtrate and/or fine solids into the formation is inevitable**; **however**, this invasion and the **potential for damage** to the formation **can be minimized with careful fluid design that is based on testing performed with cored samples of the formation of interest**.

- Formation damage also can be curtailed by expert management of downhole hydraulics using accurate modeling software, as well as by the selection of a specially designed "drill-in" fluid, such as the systems that typically are implemented while drilling horizontal wells.

Cooling and Lubricating the Bit and Drillstring:

- The bit and drillstring rotate at relatively high revolutions per minute (rev/min) all or part of the time during actual drilling operations.
- **The circulation of drilling fluid** through the drillstring and up the wellbore annular space **helps reduce friction and cools the drillstring**.
- Practically any fluid that can be circulated through the drillstring will serve to cool the bit and drillstring.
- The drilling fluid also provides a **degree of lubricity to aid the movement of the drillpipe** and bottomhole assembly (BHA) **through angles that are created intentionally by directional drilling** and/or through tight spots that can result from swelling shale.
- Lubrication, however, commonly **requires special mud characteristics that are gained by adding oil, chemicals and other materials**.
- **Oil-based fluids (OBFs) and synthetic-based fluids (SBFs) offer a high degree of lubricity** and for this reason generally are the preferred fluid types for high-angle directional wells.
- Some water-based polymer systems also provide lubricity approaching that of the oil and synthetic-based systems.

Provide Information About the Wellbore.

- Because drilling fluid is in constant contact with the wellbore, it reveals substantial information about the formations being drilled and serves as a conduit for much data collected downhole by tools located on the drillstring and through wireline-logging operations performed when the drillstring is out of the hole.

- The drilling fluid's ability to preserve the cuttings as they travel up the annulus directly affects the quality of analysis that can be performed on the cuttings.

- These cuttings serve as a primary indicator of the physical and chemical condition of the drilling fluid.

- **An optimized drilling-fluid system that helps produce a stable, in-gauge wellbore can enhance the quality of the data transmitted by downhole measurement and logging tools as well as by wireline tools.**

Walling the Borehole with an Impermeable Filter Cake:

- The hydrostatic pressure of the column of drilling fluid exerted against the walls of the borehole helps to prevent the caving of unconsolidated formations.

- A **plastering effect**, or the ability to line permeable portions of the borehole with a thin, tough **filter cake**, is also produced.

- Control of the filtration rate (water loss) is necessary for two reasons:
    1. A poor quality filter cake may cause excessive water loss and produce an excessively thick filter cake, thereby **reducing the diameter of the borehole** which **increases** the possibility of **sticking the drillstring** and the **swabbing effect** when pulling the drillpipe.
    2. High water loss can cause deep invasion of the formations, making **it difficult to interpret wireline logs.**

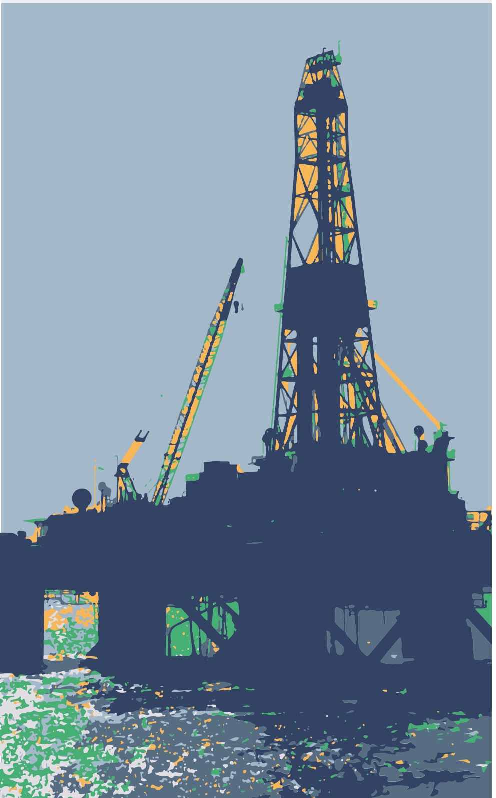
Minimize Risk to Personnel, the Environment, and Drilling Equipment.

- Drilling fluids require **daily testing and continuous monitoring** by specially trained personnel.
- The safety hazards associated with handling of any type of fluid are clearly indicated in the fluid's documentation.
- Drilling fluids also are closely scrutinized by worldwide regulatory agencies to help ensure that the formulations in use comply with regulations established to protect both natural and human communities where drilling takes place.
- At the rigsite, the **equipment used to pump or process fluid is checked constantly** for signs of wear from abrasion or chemical corrosion.
- **Elastomers used in blowout-prevention equipment are tested for compatibility with the proposed drilling-fluid system to ensure that safety is not compromised.**
- The upper hole sections typically are drilled with low-density water-based fluids (WBFs).
- Depending on formation types, downhole temperatures, directional-drilling plans, and other factors, the operator might switch to an OBF or SBF at a predetermined point in the drilling process.

- High-performance WBFs also are available to meet a variety of drilling challenges:
  - Depending on the location of the well, the drilling-fluid system can be exposed to **saltwater flows, influxes of carbon dioxide and hydrogen sulfide, solids buildup, oil or gas influxes, or extreme temperatures at both ends of the scale—or all of these.**
  - Contamination also comes from contact with the spacers and cement slurries used to permanently install casing and in the course of displacing from one drilling-fluid system to another.

- The drilling-fluid specialists who prepare drilling-fluid programs:
  - Should be aware of the operational and environmental challenges posed by any well.
  - Working closely with the operator, the specialist (who typically is supported by technical experts and a research staff) can plan for the scope of conditions that are likely to be encountered and generate a program that is both safe and cost-effective.
  - Usually includes in the planning the identification of specific performance objectives and the means by which success will be measured.

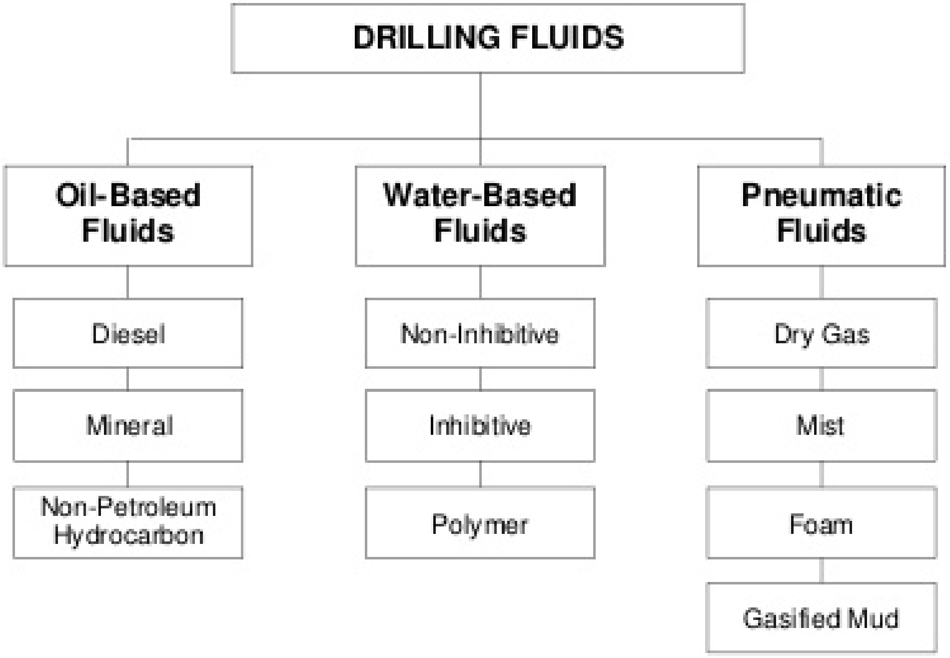
- Throughout the well-construction process:
  - The drilling-fluid personnel assigned to the operation maintain accurate records of test results, fluid volumes, drilling events, product inventory, and actions related to achieving environmental compliance.
  - The standard drilling-mud report reflects the type of information the drilling-fluid personnel (often called "mud engineers") provide at the rig site on a daily basis.
  - These reports, often computer-generated and stored in a database, and the post-well analysis performed at the conclusion of the well serve as reference materials for future wells in the same area or wells that present similar challenges.

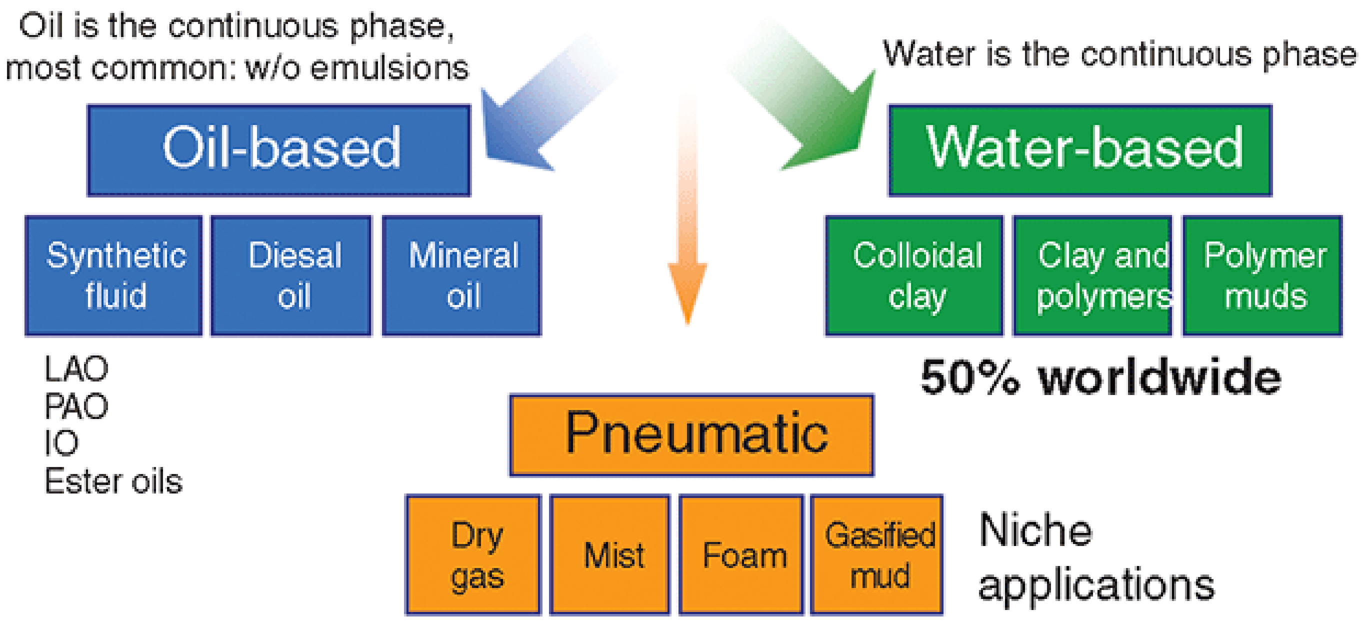


3.
Classification & types of drilling fluids.

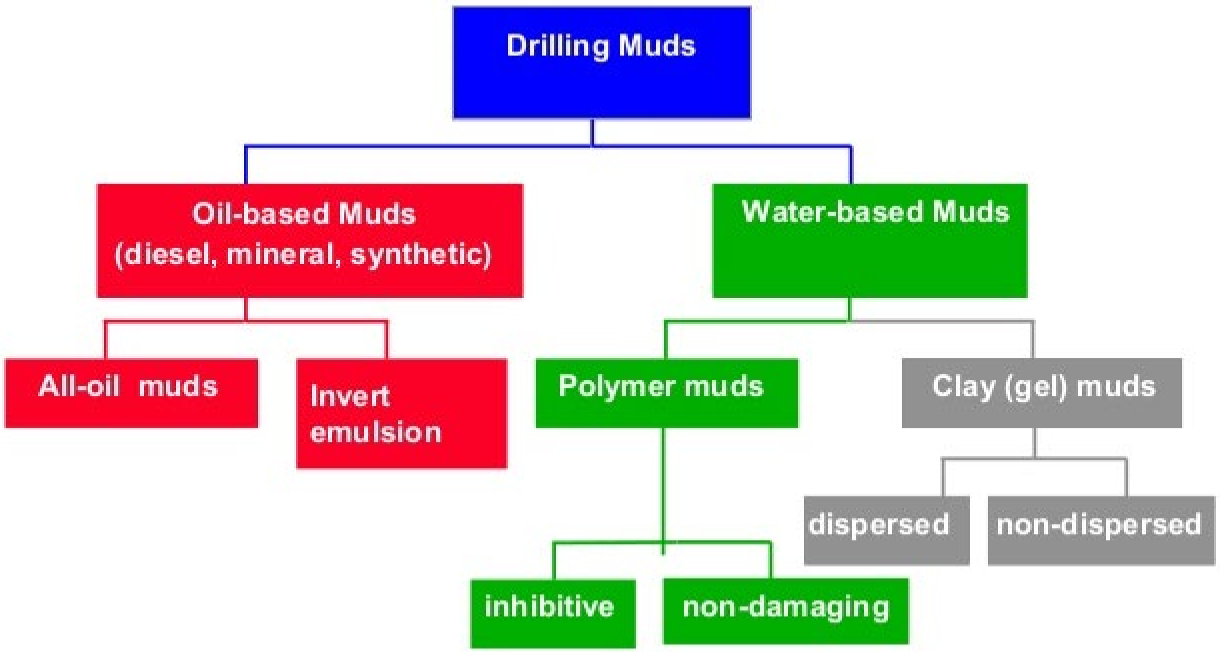
Drilling Fluid Chemistry

- While the list of chemical additives used to make the drilling fluids develop the functions previously described, is extensive, traditionally there are only three basic drilling fluid types:
  - Water/clay muds
  - Oil/water clay muds
  - Compressed gases
- Nowadays, there is fourth category:
  - Synthetic muds




Oil is the continuous phase, most common: w/o emulsions
Oil-based
Synthetic fluid
Diesal oil
Mineral oil
LAO
PAO
IO
Ester oils
Water is the continuous phase
Water-based
Colloidal clay
Clay and polymers
Polymer muds
50% worldwide
Pneumatic
Dry gas
Mist
Foam
Gasified mud
Niche applications

Drilling Mud Classification



- World Oil's annual classification of fluid systems lists **nine distinct categories** of drilling fluids, including freshwater systems, saltwater systems, oil- or synthetic-based systems, and pneumatic (air, mist, foam, gas) "fluid" systems.

- **Three key factors usually determine the type of fluid selected for a specific well:**
  - **Cost,**
  - **Technical performance, and**
  - **Environmental impact.**

- 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.

Water/Clay Muds

- This is the **major type** of mud system. Water-based fluids (WBFs) are used to drill approximately **80% of all wells**.

- A water-based mud system is a three-component system:
  - A continuous liquid phase of water in which clay materials are suspended. The base fluid may be fresh water, seawater, brine, saturated brine, or a formate brine.
  - A number of reactive solids that are added to obtain special properties.
  - Nonreactive solids (inert) that are also added to obtain other special properties.

- The type of fluid selected depends on anticipated well conditions or on the specific interval of the well being drilled.

- WBFs fall into two broad categories:
  - Nondispersed and
  - Dispersed.

- **Nondispersed sytems**
  - Simple gel-and-water systems used for tophole drilling are nondispersed, as are many of the advanced polymer systems that contain little or no bentonite.
  - The natural clays that are incorporated into nondispersed systems are managed through dilution, encapsulation, and/or flocculation.
  - A properly designed solids-control system can be used to remove fine solids from the mud system and help maintain drilling efficiency.
  - The **low-solids, nondispersed (LSND)** polymer systems rely on high- and low-molecular-weight long-chain polymers to provide viscosity and fluid-loss control. Low-colloidal solids are encapsulated and flocculated for more efficient removal at the surface, which in turn decreases dilution requirements.
  - Specially developed high-temperature polymers are available to help overcome gelation issues that might occur on high-pressure, high-temperature (HP/HT) wells.
  - **With proper treatment, some LSND systems can be weighted to 17.0 to 18.0 ppg and run at 350°F and higher.**

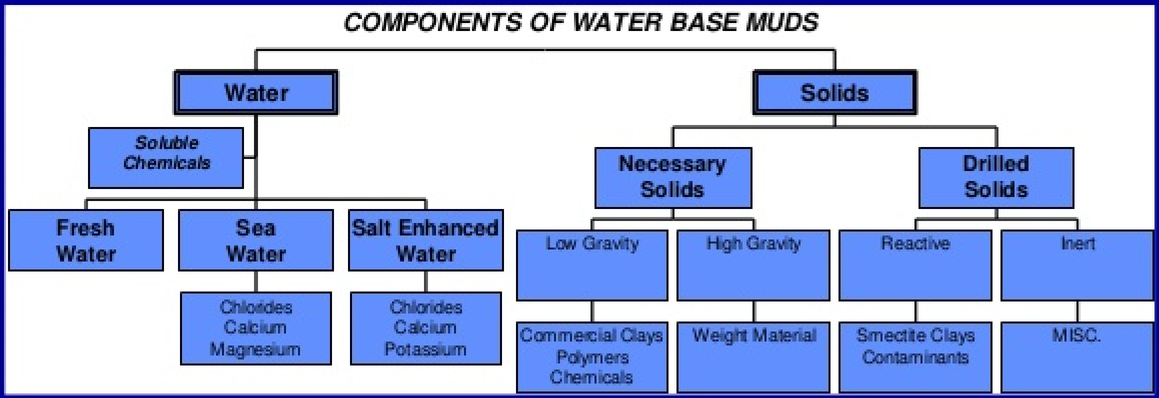
- **Dispersed systems**
  - Dispersed systems are treated with **chemical dispersants** that are designed to deflocculate clay particles to allow improved rheology control in higher-density muds.
  - Widely used dispersants include lignosulfonates, lignitic additives, and tannins.
  - Dispersed systems typically require additions of caustic soda (NaOH) to maintain a pH level of 10.0 to 11.0.
  - Dispersing a system can increase its tolerance for solids, making it possible to weight up to 20.0 ppg.
  - The commonly used lignosulfonate system relies on relatively inexpensive additives and is familiar to most operator and rig personnel.
  - Additional commonly used dispersed muds include lime and other cationic systems.
  - A solids-laden dispersed system also can decrease the rate of penetration significantly and contribute to hole erosion.

1. Water
    - This may be fresh water or salt water:
        - Seawater is commonly used in offshore drilling and saturated saltwater may be used far drilling thick evaporite sequences to prevent them from dissolving and causing washouts.
        - Saturated saltwater is also used far shale inhibition.

    - Saltwater drilling fluids:
        - They are **often used for shale inhibition and for drilling salt formations.**
        - They also are known to inhibit the formation of ice-like hydrates that can accumulate around subsea wellheads and well-control equipment, blocking lines and impeding critical operations.
        - Solids-free and low-solids systems can be formulated with high-density brines, such as:

          Calcium chloride
          Calcium bromide
          Zinc bromide
          Potassium and cesium formate

Water Base Drilling Fluids



2. Reactive Solids
   - **<u>Clays:</u>**
     - This basic material of mud is commonly referred to as "gel". It affects the viscosity, gel strength and water loss.
     - Common clays are:
       - Bentonite (for fresh water muds).
       - Attapulgite (for saltwater muds).
       - Natural formation clays (which hydrate and enter the mud system).

   - **<u>Dispersants</u>**:
     – Examples are tannins, quebracho, phosphates, lignite and lignosulphonates.
     - They reduce viscosity by adsorption onto clay particles, reducing the attraction between particles.

- **Filtration Control Agents:**
  - Function: they control the amount of water loss into permeable formations, due to the pressure differential, by ensuring the development of a firm impermeable filter cake.
  - Some are:
    - Starch: pregelatinized to prevent fermentation
    - Sodium carboxy-methyl cellulose (CMC): organic colloid of long chain molecules which can be polymerized in to different lengths or "grades". The grades depend on the desired viscosity.
    - Polymers: for example cypan, drispac, used under special conditions.

- **Detergents, Emulsifiers and Lubricants:** to assist in cooling and lubricating. Also used for a spotting fluid in order to free stuck pipe.

- **Defoamers:** these prevent mud foaming at the surface in treatment equipment.

- **Sodium Compounds:** precipitate or suppress calcium or magnesium which decreases the yield of the clays.

- **Calcium Compounds:** they inhibit formation clays and prevent them from hydrating or swelling.

3. Inert Solids

- **Weight Material:**
    - Function: finely ground, high-density minerals, held in suspension to control mud density.
    - Common weight materials are barite, hematite and galena.

- **Lost Circulation Material (L.C.M.):**
  - Function: it is added to the mud system in order **to bridge-over or plug the point of loss.**
  - It is available in many sizes and types to suit particular circulation loss:
    - Fibrous: wood fiber, leather fiber, etc.
    - Granular: walnut shells (nut plug), fine, medium, coarse.
    - Flakes: cellophane, mica (fine, coarse).
    - Reinforcing Plugs: bentonite with diesel oíl, time setting clays, attapulgite and granular (squeeze).
  - If none of these materials successfully plug the lost circulation zone, the zone must be cemented off.

- **Anti-friction material:**
  - It is added to the mud system to **reduce torque and decrease the possibility of differential sticking.**
  - The most frequently used material is inert polyurethane spheres.
  - More frequently it is used on high angle directional wells, where torque and differential sticking are a problem.

Oil/Water/Clay Muds:

- 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**

- Two basic types of oil/water mud systems are used:
    - Emulsion (oil/water) System, in which diesel or crude oil is dispersed in a continuous phase of water.
    - Invert Emulsion (water/oil) System, in which water is dispersed in a continuous phase of diesel/crude oil.

- These mud systems have desirable properties as completion fluids or when drilling production wells.

- Oil-based fluids (OBFs) in use today are formulated with diesel, mineral oil, or low-toxicity linear olefins and paraffins.
- The olefins and paraffins are often referred to as "synthetics" although some are derived from distillation of crude oil and some are chemically synthesised from smaller molecules.
- The electrical stability of the internal brine or water phase is monitored to help ensure that the strength of the emulsion is maintained at or near a predetermined value.
- The emulsion should be stable enough to incorporate additional water volume if a downhole water flow is encountered.
- They are nonreactive with clays and their filtrate will not damage the formations.
- Their high cost and difficulty of running, and complication of geological evaluation preclude their use on exploratory wells, other than in certain troublesome evaporite and clay sections.
- Apart from these emulsions containing roughly equal portions of oil and water, there are true oil-based muds which may contain only 5 percent water.
- When oil-based mud systems are in use, special considerations must be made regarding formation evaluation.

- Barite is used to increase system density, and specially-treated organophilic bentonite is the primary viscosifier in most oil-based systems.
- The emulsified water phase also contributes to fluid viscosity.
- Organophilic lignitic, asphaltic and polymeric materials are added to help control HP/HT(High pressure/High temperature) fluid loss.
- Oil-wetting is essential for ensuring that particulate materials remain in suspension.
- The surfactants used for oil-wetting also can work as thinners.
- Oil-based systems usually contain lime to maintain an elevated pH, resist adverse effects of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) gases, and enhance emulsion stability.

- Shale inhibition is one of the key benefits of using an oil-based system:
  - The high-salinity water phase helps to prevent shales from hydrating, swelling, and sloughing into the wellbore.
  - Most conventional oil-based mud (OBM) systems are formulated with calcium chloride brine, which appears to offer the best inhibition properties for most shales.

- The ratio of the oil percentage to the water percentage in the liquid phase of an oil-based system is called its oil/water ratio.
- **Oil-based systems** generally function well with an oil/water ratio in the range from **65/35 to 95/5**, **but the most commonly** observed range is from **70/30 to 90/10**.

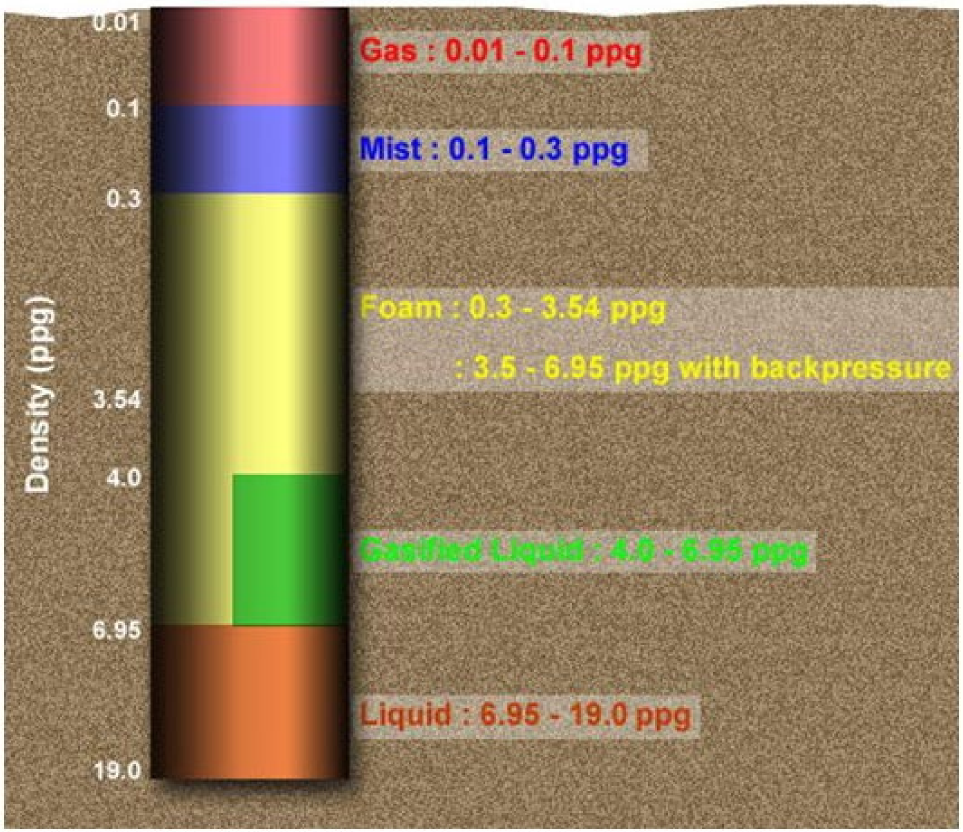
- The discharge of whole fluid or cuttings generated with OBFs is not permitted in most offshore-drilling areas.
- All such drilled cuttings and waste fluids are processed, and shipped to shore for disposal.
- Whereas many land wells continue to be drilled with diesel-based fluids, the development of synthetic-based fluids (SBFs) in the late 1980s provided new options to offshore operators who depend on the drilling performance of oil-based systems to help hold down overall drilling costs but require more environmentally-friendly fluids.
- In some areas of the world such as the North Sea, even these fluids are prohibited for offshore discharge.

Pneumatic-drilling fluids

- **Compressed air or natural gas** can occasionally be used in place of drilling fluid (at times with a foaming agent to improve carrying capacity), to circulate cuttings out of the wellbore, but its use is applicable only in areas where there is little formation water.
- The **compressed air or gas is circulated the same as conventional drilling mud**, except compressors are used instead of mud pumps.
- Pneumatic fluids fall into one of three categories:
    - Air or gas only
    - Aerated fluid
    - Foam

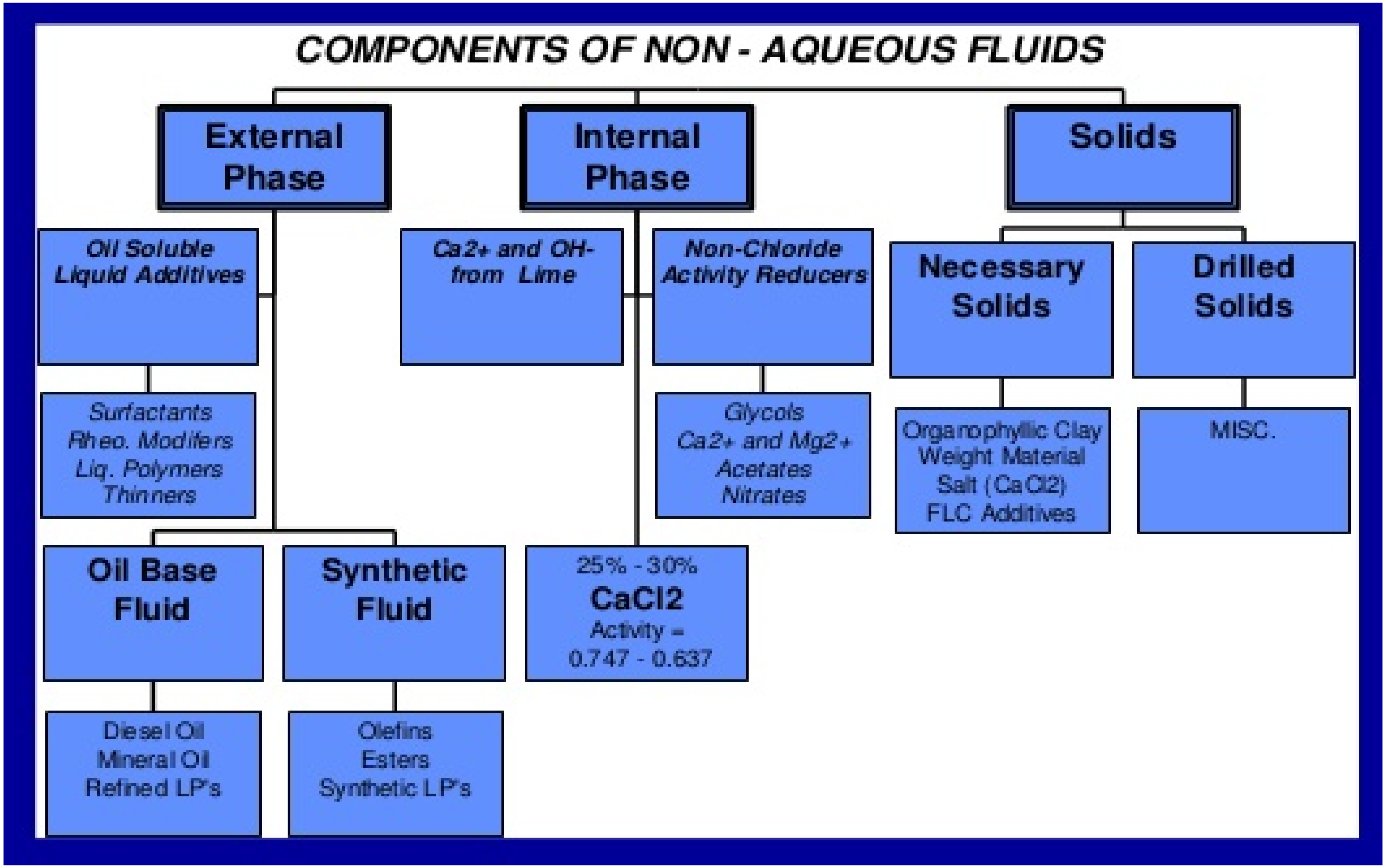
- Except when drilling through high-pressure hydrocarbon or fluid-laden formations that demand a high-density fluid to prevent well-control issues, using pneumatic fluids offers several **advantages**:
    - **Little or no formation damage.**
    - **Rapid evaluation of cuttings for the presence of hydrocarbons.**
    - **Prevention of lost circulation.**
    - **Significantly higher penetration rates in hard-rock formations**

Pneumatic Fluids (Air, Gas, Mist, Foams, Gasified Muds)



Prepared by: Tan Nguyen

- Pneumatic-drilling operations require **specialized equipment** to help ensure **safe management** of the cuttings and formation fluids that return to surface, as well as tanks, compressors, lines, and valves associated with the gas used for drilling or aerating the drilling fluid or foam.


COMPONENTS OF NON - AQUEOUS FLUIDS
External Phase
Internal Phase
Solids
Oil Soluble Liquid Additives
Surfactants
Rheo. Modifers
Liq. Polymers
Thinners
Oil Base Fluid
Diesel Oil
Mineral Oil
Refined LP's
Synthetic Fluid
Olefins
Esters
Synthetic LP's
Ca2+ and OH- from Lime
Non-Chloride Activity Reducers
Glycols
Ca2+ and Mg2+
Acetates
Nitrates
25% - 30%
CaCl2
Activity =
0.747 - 0.637
Necessary Solids
Organophyllic Clay
Weight Material
Salt (CaCl2)
FLC Additives
Drilled Solids
MISC.

Synthetic-based drilling fluids

- Synthetic-based fluids were developed in1990s 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 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).

- Properties:
  - **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.
  - However, a shorter-chain-length (C8), low-viscosity ester that was developed in 2000, exhibits viscosity similar to or lower than that of the other base fluids, specifically the heavily used IO systems.
  - Because of their high biodegradability and low toxicity, esters are universally recognized as the best base fluid for environmental performance.

- Until operators began drilling in deepwater locations, where the pore pressure/fracture gradient (PP/FG) margin is very narrow and mile-long risers are not uncommon, the standard synthetic formulations provided satisfactory performance. However, the issues that arose because of deepwater drilling and changing environmental regulations prompted a closer examination of several seemingly essential additives.

- In deepwater drilling, when cold temperatures are encountered, conventional SBFs might develop **undesirably high viscosities as a result of the organophilic clay and lignitic additives in the system**. The introduction of SBFs formulated with zero or minimal additions of organophilic clay and lignitic products allowed rheological and fluid-loss properties to be controlled through the fluid-emulsion characteristics.

- The performance advantages of these systems include:
    - High, flat gel strengths that break with minimal initiation pressure
    - Significantly lower equivalent circulating densities (ECDs)
    - Reduced mud losses while drilling, running casing, and cementing

Polymer drilling fluids

- Polymer drilling fluids are used to **drill reactive formations** where the **requirement for shale inhibition is significant**.

- **Shale inhibitors frequently used are salts, glycols and amines, all of which are incompatible with the use of bentonite.**

- These systems typically derive their viscosity profile from polymers such as:
  - Xanthan gum and fluid loss control from starch or cellulose derivatives.
  - Potassium chloride, that is an inexpensive and highly effective shale inhibitor which is widely used as the base brine for polymer drilling fluids in many parts of the world.
  - Glycol and amine-based inhibitors can be added to further enhance the inhibitive properties of these fluids.

Drill-in fluids

- Drilling into a pay zone with a conventional fluid can introduce a host of previously undefined risks, all of which diminish reservoir connectivity with the wellbore or reduce formation permeability.

- This is particularly true in horizontal wells, where the pay zone can be exposed to the drilling fluid over a long interval.

- Selecting the most suitable fluid system for drilling into the pay zone requires a thorough understanding of the reservoir.

- Using data generated by lab testing on core plugs from carefully selected pay zone cores, a reservoir-fluid-sensitivity study should be conducted to determine the morphological and mineralogical composition of the reservoir rock.

- Natural reservoir fluids should be analyzed to establish their chemical makeup.

- The degree of damage that could be caused by anticipated problems can be modeled, as can the effectiveness of possible solutions for mitigating the risks.

- A drill-in fluid (DIF) is a **clean fluid that is designed to cause little or no loss of the natural permeability of the pay zone**, and to **provide superior hole cleaning and easy cleanup.**
- DIFs can be:
    - Water-based
    - Brine-based
    - Oil-based
    - Synthetic-based

- In **addition to being safe and economical for the application**, a DIF should be **compatible with the reservoir's native fluids to avoid causing precipitation of salts or production of emulsions.**

- A suitable nondamaging fluid should establish a **filter cake** on the face of the formation, but should **not penetrate** too far into the formation pore pattern. The fluid filtrate should inhibit or prevent swelling of reactive clay particles within the pore throats.

- Formation damage commonly is caused by:
    - Pay zone invasion and plugging by fine particles
    - Formation clay swelling
    - Commingling of incompatible fluids
    - Movement of dislodged formation pore-filling particles
    - Changes in reservoir-rock wettability
    - Formation of emulsions or water blocks
    - Once a damage mechanism has diminished the permeability of a reservoir, it seldom is possible to restore the reservoir to its original condition.

Specialty Products.

- Drilling-fluid service companies provide a wide range of additives that are designed to prevent or mitigate costly well-construction delays.
- Examples:
  - **Lost-circulation materials (LCM)** that help to prevent or stop downhole mud losses into weak or depleted formations.
  - **Spotting fluids** that help **to free stuck pipe**.
  - **Lubricants for WBFs** that ease torque and drag and facilitate drilling in high-angle environments.
  - **Protective chemicals** (e.g., scale and corrosion inhibitors, biocides, and H_2S scavengers) that prevent damage to tubulars and personnel.

LCMs.

- Many types of LCM are available to address loss situations:
  - Sized calcium carbonate, mica, fibrous material, cellophane, and crushed walnut shells have been used for decades.
  - The development of deformable graphitic materials that can continuously seal off fractures under changing pressure conditions has allowed operators to cure some types of losses more consistently.
  - The application of these and similar materials to actually strengthen the wellbore has proved successful.
  - Hydratable and rapid-set lost-circulation pills also are effective for curing severe and total losses.

Spotting Fluids.

- Most spotting fluids are designed to **penetrate and break up the wall cake** around the drillstring.
- A soak period usually is required to achieve results.
- Spotting fluids typically are formulated with a base fluid and additives that can be incorporated into the active mud system with no adverse effects after the pipe is freed and/or circulation resumes.

Lubricants.

- Lubricants might contain hydrocarbon-based materials or can be formulated specifically **for use in areas where environmental regulations prohibit the use of an oil-based additive.**
- Tiny glass or polymer beads also can be added to the drilling fluid to increase lubricity.
- Lubricants are designed to reduce friction in metal-to-metal contact and to provide lubricity to the drillstring in the open hole, especially in deviated wells, where the drillstring is likely to have continuous contact with the wellbore.

Corrosion Inhibitors, Biocides, and Scavengers.

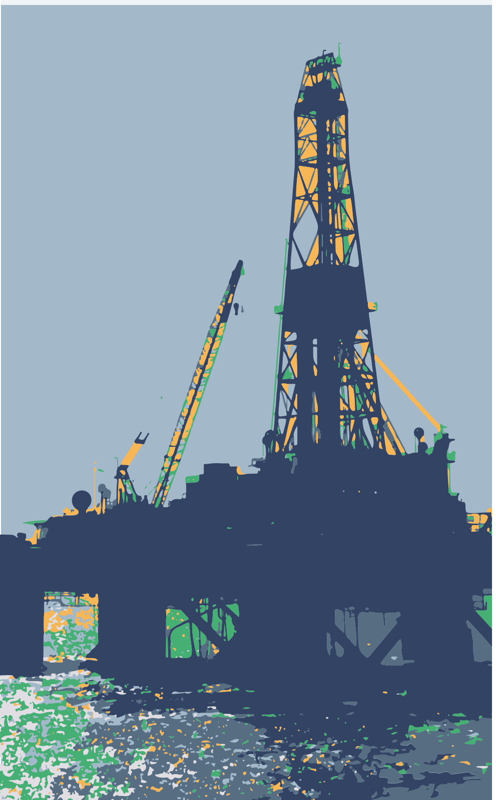
- Corrosion **causes the majority of drillpipe loss** and also damages casing, mud pumps, bits, and downhole tools.
- As downhole temperatures increase, corrosion also increases at a corresponding rate if the drillstring is not protected by chemical treatment.
- Abrasive materials in the drilling fluid can accelerate corrosion by scouring away protective films.
- **Corrosion typically is caused by one or more factors that include:**
  - **Exposure to oxygen, H_2S, and/or CO_2;**
  - **Bacterial activity in the drilling fluid;**
  - **High-temperature environments;**
  - **Contact with sulfur-containing materials.**

- Drillstring coupons can be inserted between joints of drillpipe as the pipe is tripped in the hole.
- When the pipe next is tripped out of the hole, the coupon can be examined for signs of pitting and corrosion to determine whether the drillstring components are undergoing similar damage.

- H_2S and CO_2 frequently are present in the same formation.

- Scavenger and inhibitor treatments should be designed to counteract both gases if an influx occurs because of underbalanced drilling conditions.

- Maintaining a high pH helps control H_2S and CO_2 and prevents bacteria from souring the drilling fluid. Bacteria also can be controlled using a microbiocide additive.



4.
Drilling-Fluids Testing.

Field Tests.

- The drilling-fluids specialist in the field conducts a number of tests to determine the properties of the drilling-fluid system and evaluate treatment needs.
  - Drillingfluid companies might use some tests that are designed for evaluating a proprietary product
  - The vast majority of field tests are standardized according to American Petroleum Institute Recommended Practices (API RP) 13B-17 and 13B-2,8 for WBFs and OBFs, respectively.

- Following table shows typical API-recommended field tests for WBFs.

- Typical API-recommended field tests for OBFs and SBFs are also shown.

- Several tests for OBFs and SBFs are identical to those performed on WBFs.

- For all three fluid types, depending on the type of fluid in use, some or all tests should be performed.

Typical field test for WBFs

Drilling-fluid density	Mud weight in ppg or equivalent unit of measure, as appropriate to the región (e.g., specific gravity (SG))
Viscosity	Viscosity exhibited when a specific quantity of fluid is poured through a Marsh funnel (typically recorded in seconds per Quart)
Rheology	Rheological properties exhibited at various rotational speeds using a viscometer (also called rheometer). Some viscometer can test the fluid at multiple speeds and temperaturas to give a detailed viscosity profile for the fluid.
Gel strength	Suspension characteristics developed over specified time.
Filtration	Surface indication of filtrate invasión into the near wellbore (also called fluid los). Performed under LP/LT conditions ans HP/HT conditions as required.
Retort analysis	Percentages of wáter, oil ans solids making up the active system.
Sand content	Percentage of sand in the active system.

Typical field test for WBFs

Methylene blue capacity	Clay content in the active system [also commonly called methylene blue tes (MBT)]
pH	Indication of system acidity or alkalinity.
Chemical análisis: **Alkalinity/lime content** **Chlorides** **Total hardness (calcium)**	Indication of variations from base-fluid formulatiion caused by Surface treatment and/or influx or contamination from downhole formations.

Typical field test for OBFs ans SBFs

Drilling-fluid density	Mud weight in ppg or equivalent unit of measure, as appropriate to the región (e.g., specific gravity (SG))
Viscosity	Viscosity exhibited when a specific quantity of fluid is poured through a Marsh funnel (typically recorded in seconds per Quart)
Rheology	Rheological properties exhibited at various rotational speeds using a viscometer (also called rheometer). Some viscometer can test the fluid at multiple speeds and temperaturas to give a detailed viscosity profile for the fluid.
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Retort analysis	Percentages of wáter, oil ans solids making up the active system.
Sand content	Percentage of sand in the active system.
Chemical análisis: **Alkalinity/lime content** **Chlorides** **Total hardness (calcium)**	Indication of variations from base-fluid formulatiion caused by Surface treatment and/or influx or contamination from downhole formations.

Typical field test for OBFs ans SBFs

Electrical stability (ES)	Indication of emulsión stability of the wáter pase of the oil or synthetic-based system, performed with an Es meter.
Water-pase salinity	Presence of chlorides, in parts per million (ppm).
Sulfide concentration	Indication of the concentration of soluble sulfides, in ppm, performed with Garrett gas-train apparatus.

Laboratory Tests.

- Extensive testing of the fluid is performed in the design phase of the fluid:
  - To achieve desired fluid characteristics
  - To determine the performance limitations of the fluid.

- Laboratory testing aids in fluid design and expands the capacity to monitor and evaluate fluids when field-testing procedures prove inadequate.
- Some laboratory tests are identical to field testing methods, whereas others are unique to the laboratory environment.
- In the laboratory setting, testing and equipment are available to determine:
  - Toxicity
  - Fluid rheology
  - Fluid loss
  - Particle plugging
  - High-angle sag
  - Dynamic high-angle sag
  - High-temperature fluid aging
  - Cuttings erosion

Laboratory Tests.

- Shale stability
- Capillary suction
- Lubricity
- Return permeability
- X-ray diffraction
- Particle-size distribution (PSD).

- **Toxicity.**
  - The environmental and toxicity standards of the region in which the fluid is being used will require testing either of the whole drilling fluid or of its individual components.
  - Toxicity tests generally are used for offshore applications.
  - An **approved laboratory** can perform the proper testing to ensure compliance of the fluid or its components.

- **Fluid Rheology.**
  - Important parameter of drilling-fluid performance.
  - For critical offshore applications with extreme temperature and pressure requirements, the viscosity profile of the fluid often is measured with a controlled-temperature and pressure viscometer.
  - Fluids can be tested at temperatures of < 35°F to 500°F (-37,2 °C to 260°C), with pressures of up to 20,000 psia.
  - Cold-fluid rheology is important because of the low temperatures that the fluid is exposed to in deepwater risers.
  - High temperatures can be encountered in deep wells or in geothermally heated wells.
  - The fluid can be under tremendous pressure downhole, and its viscosity profile can change accordingly.

- **Fluid Loss.**
  - In the field, LP/LT and HP/HT fluid loss tests are performed routinely.
  - If fluid (or filtration) loss is excessive, formation instability, formation damage, or a fractured formation and loss of drilling fluid can occur.
  - Fluid loss can be measured under dynamic conditions using a viscometer, which incorporates a rotating bob to provide fluid shear in the center of a ceramic-filter core.
    - The fluid is heated and pressurized.
    - Fluid loss is measured radially through the entire core, giving a sophisticated simulation of the drilling fluid circulating in the wellbore.

- **Particle Plugging.**
  - The particle-plugging test (PPT) often is used to evaluate the ability of plugging particles added to a fluid to mitigate formation damage by stopping or slowing filtrate invasion into a core.
  - A PPT uses an inverted HP/HT-filter-press cell that has been fitted with a ceramic disk as a filtering medium and is pressurized with a hydraulic cylinder.
  - Ceramic disks with different mean pore-throat diameters are used to simulate a wellbore wall.
  - A PPT typically is run with a 2,000-psi or higher differential pressure.
  - The spurt loss and total fluid loss are measured over a 30-minute period.
  - The cell is inverted, and fluid loss is measured from the top of the cell to eliminate the effects of fluid settling.

- **<u>High-Angle Sag and Dynamic High-Angle Sag.</u>**
  - The weighting material used to increase the density of the drilling fluid can settle at a faster rate in an angled well than in a vertical well.
  - The high-angle sag test (HAST) and dynamic high-angle sag test (DHAST) measure density differences in the fluid as the angle of drilling changes.
  - The HAST is used with fluids under static conditions, whereas the DHAST is used under dynamic conditions, in which the fluid can be subjected to shear or observed statically.
  - The DHAST has temperature and pressure specifications of 350°F (176,6 °C) and 10,000 psia, respectively.
  - Measuring the changes in density allows the fluid's propensity to undergo these changes in the drilling process to be evaluated and curtailed by modifications to the fluid design.

- **<u>High-Temperature Fluid Aging.</u>**
  - Over time, high temperatures can degrade the components of a drilling fluid and alter its performance.
  - High-temperature aging of the fluid is conducted to assess the impact that temperatures > 250°F (over 121°C) have on performance.
  - Fluid can be aged statically and dynamically.
    - In the static-aging process, the fluid is placed in a pressurized cell and allowed to stand without rolling at the desired test temperature for a desired length of time (rarely < 16 hours). This simulates the stress the fluid might be subjected to during static periods in the wellbore (e.g., logging and tripping).
    - In dynamic aging, the fluid is rolled in a pressurized cell at the desired test temperature to simulate the fluid under drilling conditions.
  - After undergoing aging, the fluid can be evaluated using the same tests that are applied to nonaged fluid.

- **Cuttings Erosion.**
  - If drilled cuttings undergo significant erosion before being removed from the drilling fluid, that fluid's colloidal content can increase and interfere with drilling performance.
  - Also, cuttings erosion usually is accompanied by wellbore erosion, which leads to hole washout.
  - Two tests are available to aid in designing fluids that reduce cuttings erosion.
    - Method 1 is an API-approved method:
      - In this one, the user measures out a known amount of shale material that is representative of the formation to be drilled and that has been broken and sized between No. 6 and No. 12 shaker screens.
      - The shale then is placed in a jar and exposed to the drilling fluid, where it is aged by hot-rolling it at 150°F for 16 hours.
      - After aging, the shale is collected on the No. 12 shaker screen, carefully washed, and dried.
      - The percent recovery then is calculated on the basis of the weight of the recovered shale vs. that of the shale originally used.
      - Variations of this method are used for individual component testing.
      - The aging time is varied to determine the erosion rate.

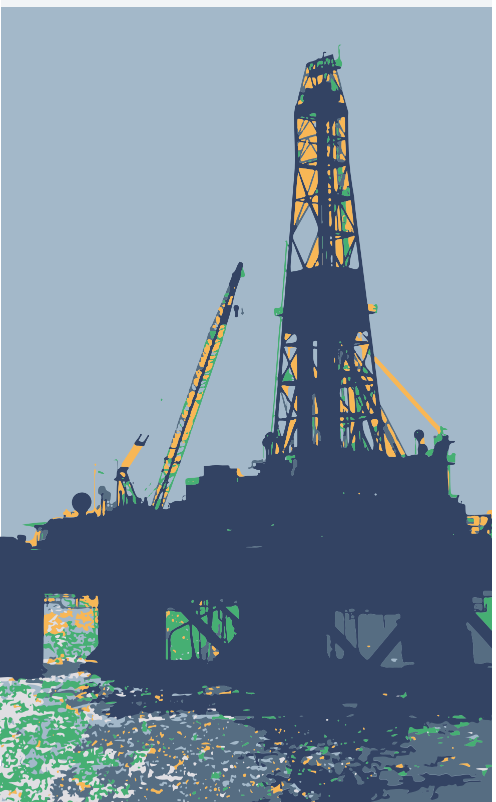
- **Cuttings Erosion.**
  - Method 2 or second available test is the slake-durability tester, which measures chemical and mechanical erosion to the shale.
    - This tester resembles the API-approved method in that it uses a known amount of test shale and in that recovery is calculated in the same way. It differs in that the shale sample is placed inside a mesh-screen cage that is immersed in the drilling fluid and rolled continually throughout the test.

- **Shale Stability.**
  - Reactive shales cause many difficulties in a drilling operation.
  - Fluids should be designed to mitigate these shale problems.
  - Along with erosion testing, four other distinct tests are used to assess the interaction between the drilling fluid and shale:
    - Capillary suction time (CST)
    - Return permeability
    - X-ray diffraction
    - PSD.
  - **CST.**
    - The CST test investigates the chemical effects of the drilling fluid on the dispersive properties of shale and active clays.
    - The CST test measures filter-cake permeability by timing the capillary action of filtrate onto a paper medium.
    - Changes in permeability then can be related to the inhibitive characteristics of the fluid.

- **Return Permeability.**
  - When drilling reaches a hydrocarbon-bearing zone, of great concern is the potential to damage the formation and thereby to reduce the ability of the well to produce hydrocarbons.
  - A return-permeability test can reveal formation damage and can be conducted using a return permeameter.
  - The porosity and conductivity of a core sample are determined by flowing a refined mineral oil through the core.
  - To simulate fluid and filtrate invasion into the core, drilling fluid then is placed against the outflow side of the core, and differential pressure is applied in the direction opposite that of the previous flow measurement.
  - After contamination, mineral oil again is flowed through the core in the original direction, and the resultant porosity is compared to the original porosity to determine whether a reduction in permeability has occurred.

- **X-Ray Diffraction.**
  - Knowing the mineral composition of a formation to be drilled is important for determining how the drilling fluid will react with the formation and how to prevent potential drilling problems.
  - Fluid labs use X-ray diffraction to determine the mineralogical composition of shale or cuttings.
  - They expose a crystalline mineral sample to X-ray radiation and then compare the resultant diffraction pattern to known standards to determine which minerals are present in the sample.

- **PSD.**
  - Particle-size distributions are determined for various solid materials that are added to drilling fluids.
  - A particle-size analyzer determines PSD by measuring laser-light diffraction, which then can be related to particle size.
  - PSDs are used to determine what screen size is needed for removing particles from the fluid system for conditioning, whether the particles present are small enough to cause formation damage by becoming trapped in the formation's pores, and whether the present distribution of particle sizes will allow effective bridging of pore openings to help control fluid loss without causing excessive formation damage.



5.
Mud Logging.

Mud Logging activities

- Mud Logging **acquires, monitors and records in real time geological and drilling data** generated during construction of a wellbore via sensor, calculated measurements, geological and hydrocarbon sample analysis.
- This activity is performed 24/24h – 7/7 days and includes:
  - **Monitoring of drilling performance and operational safety.**
  - **Gas and cuttings analysis for formation evaluation.**
- Mudloggers are the "eyes & ears of the drilling team."

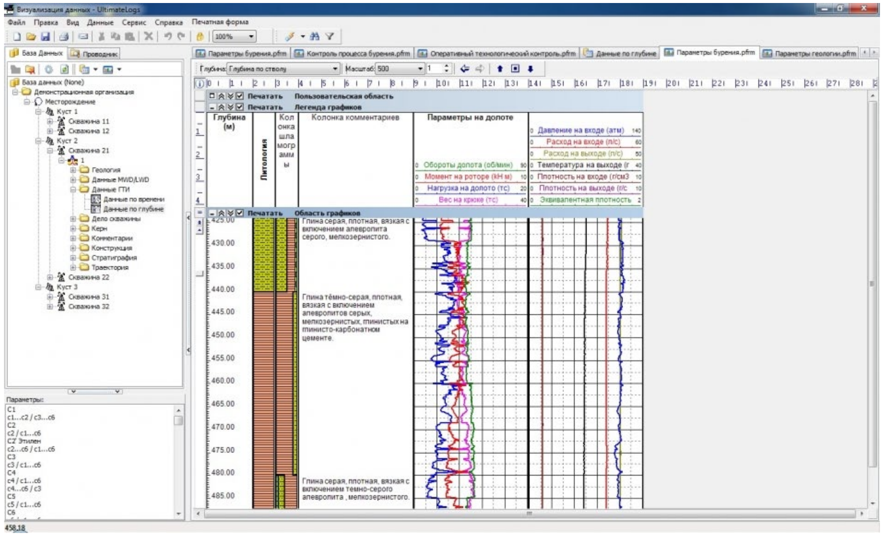
- The art and science of …
    - acquiring,
    - storing,
    - interpreting,
    - understanding,
    - presenting,
    - and delivering,

… geological, hydrocarbon, drilling and other wellsite/rigsite information while a well is being drilled.

- This is done by:
    - Monitoring and recording trends
        - Drilling parameters
        - Cuttings geology
        - Cavings volume & rate
    - Identifying
        - Formation types/tops
        - Formation pressures
        - Lag times – volumes
    - Communicating

DS AND HYDRAULICS

- Basic Surface Logging involves the collection of rock cuttings during drilling and their interpretation.
- Gas analysis and basic engineering parameters are also monitored and recorded, and a 'mudlog' constructed.
- The mudlog is usually the only continuous record of the well and its construction process.
- In addition to the 'Mudlog', Drilling engineering and Formation Pressure logs are constructed
- These record direct measurement of parameters, or interpreted values such as pore pressure
- These assist in determining the performance of the bit and BHA through the well, and the environmental factors they are subjected to



- Mud Logging is part of the Well Control chain:
  - Help Rig crew and Company to understand if operations are running properly and provide data to allow them to take quick and appropriate decisions.
  - A Key duty is to monitor drilling conditions for possible influxes, or losses.
  - Detection and early warning of dangerous gases coming from the well: H_2S, CO_2 and Hydrocarbons.
  - Provide alarm system at rig site: All parameters can be set against visual and audible alarms.
  - Communications and teamwork are key.
- All the data will be used to plan further wells by the client so it must be accurate, relevant, and presented in an understandable format.

Sampling and Cuttings Analysis

- There is no substitute for representative cuttings samples correlated to depth: cuttings and cores are the only direct data available. This is fundamental for:
  - Acquire knowledge about the type of rock for geological interpretation (tops, boundaries, source, depositional environment etc.).
  - Determining the reservoir properties and characteristics for evaluation of the reservoir potential and recognition of reservoirs.
  - Allowing to others to recognize the rock when it is seen again.
- All geological data is entered into the mudlog.
- Data includes:
  - Percentage lithology
  - Interpreted lithology
  - Lithological descriptions
  - Hydrocarbon shows
  - Formation tops
  - Cavings
  - Calcimetry
  - Core data
  - Comments/annotations

- Gas sampling:
  - Gas analysis is important both for commercial reasons and for safety reasons.
  - This sampling involves collection, detection and analysis of gas returning to surface in the mud stream.
  - Types of gas commonly analyzed include:
    - Hydrocarbons from the formation
    - Hydrogen Sulphide from the formation
    - Carbon Dioxide from the formation
    - Acetylene introduced for lag calculations

- Hydrocarbons to be sampled:
  - Drilled cuttings are carried up the annulus.
  - Gas, if present, will be released into the mud.
  - At surface, collection equipment will remove this gas for analysis.
  - Gas will be analyzed as:
    - Total gas present (in %EMA, units, or %LEL).
    - Chromatogram of individual gases (in ppm).