SKM 3413 - DRILLING ENGINEERING

Chapter 2 - Drilling Fluids

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Functions of drilling fluids

- Cools & lubricates the bit & drill string
- Suspends cuttings & weighting materials when circulation is stopped
- Supports part of the weight of the drill string or casing
- Controls subsurface formation pressures
- Removes & transports cuttings from the bottom of the hole to the surface

Functions of drilling fluids (ctd)

- Walls the hole with an impermeable filter cake
- Minimizes sloughing & caving of the formation.
- Helps to obtain good, downhole data for formation analysis.
- Transmits hydraulic horse power to the bit.
- Prevent corrosion fatigue of drill pipe

To achieve these functions, the following side effects must be minimized (mud should not):

- Reduce the penetration rate
- Loss of circulation
- Erode of the borehole
- Corrode the drill string
- Wear on the pump parts
- Swell the borehole creating tight spots
- Damage the subsurface formation, especially the potential pay section
- Stuck the drill pipe against the walls of the hole
- Hamper evaluation of the productive zone
- Require excessive pump pressure at the desired circulation rate
- Allow suspension & continual circulation of undesirable solids and/or abrasive solids such as cuttings, encountered clay & fine sand

Advantages of having a good mud cake on permeable formation

- Minimizes formation damage (affecting both formation evaluation & production)
- Improves hole stability (avoiding wall stuck pipe, swabbing & pressure surges)
- Reduces fluid loss
- Reduced contamination of formation
- Reduced sloughing & caving

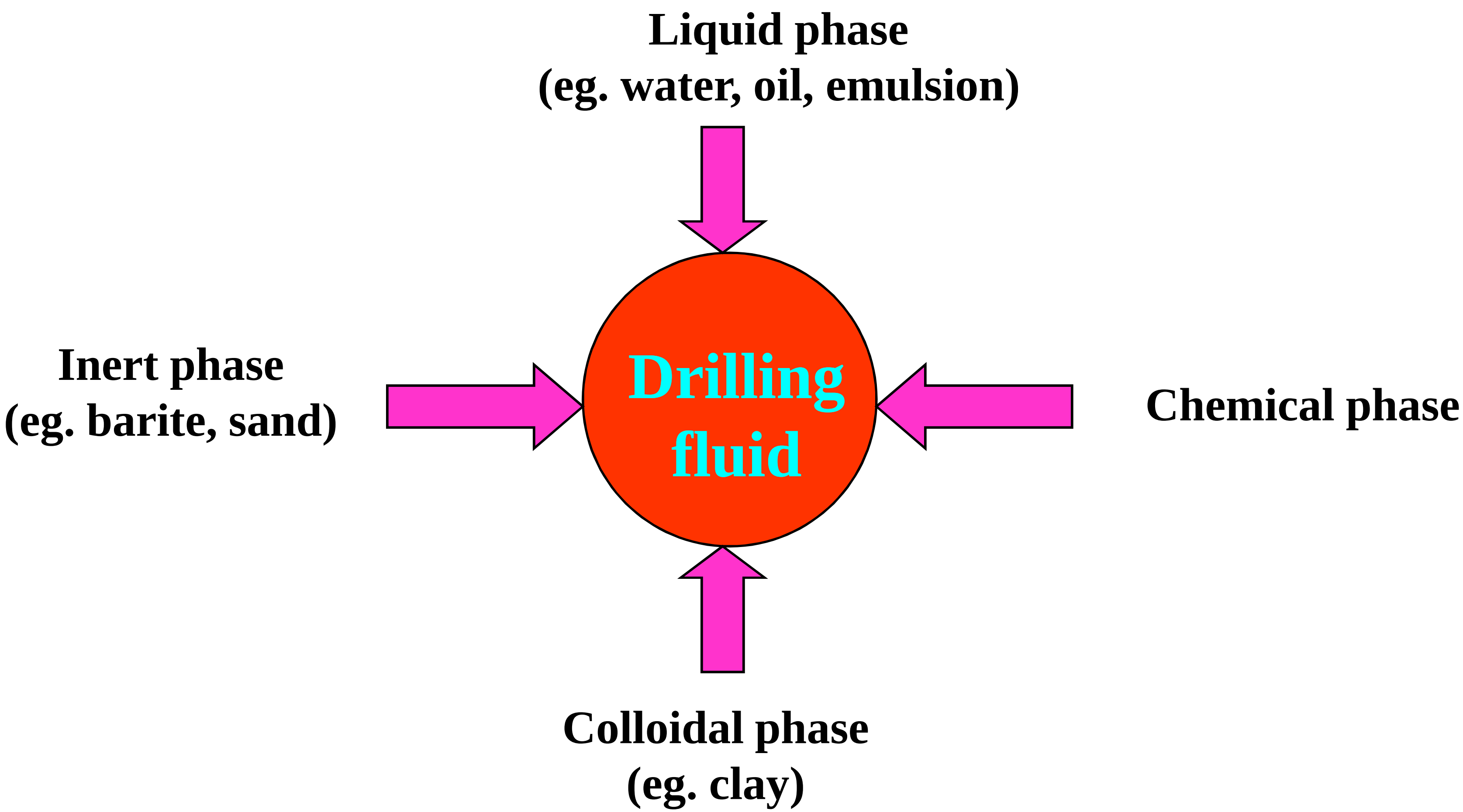
To obtain more efficient cuttings removal:

- Increase annular fluid velocity (if too low)
- Change flow pattern
- Increase mud viscosity

What is "rheology"

- The study of how matter deforms and flows.
- Primarily concerned with the relationship of ***shear stress*** and ***shear rate*** and the impact these have on flow characteristics inside ***tubulars*** and ***annular spaces***.

Components of drilling fluid



Common mud addtives

Weighting Materials
- Barite
- Hematite
- Galena
- Calcium carbonate
- Dissolved salts

Emulsifiers
- Oil in water
- Water in oil

Viscosity-Reducing Chemicals
- Phosphates
- Tannates
- Lignites
- Lignosulfonate
- Sodium polyacrylate

Fluid-Loss Reducers
- Starches
- CMC
- Polyanionic cellulose Acrylates
- Bentonite
- Dispersants

Viscosifiers (Thickeners)
- Bentonite
- Attapulgite
- Asbestos
- Polymers

Lost-Circulation Materials
- Granular
- Fibrous
- Flaked
- Slurries

Special Additives
- Flocculants
- Corrosion control
- Defoamer
- pH control
- Mud lubricant
- Antidifferential sticking material

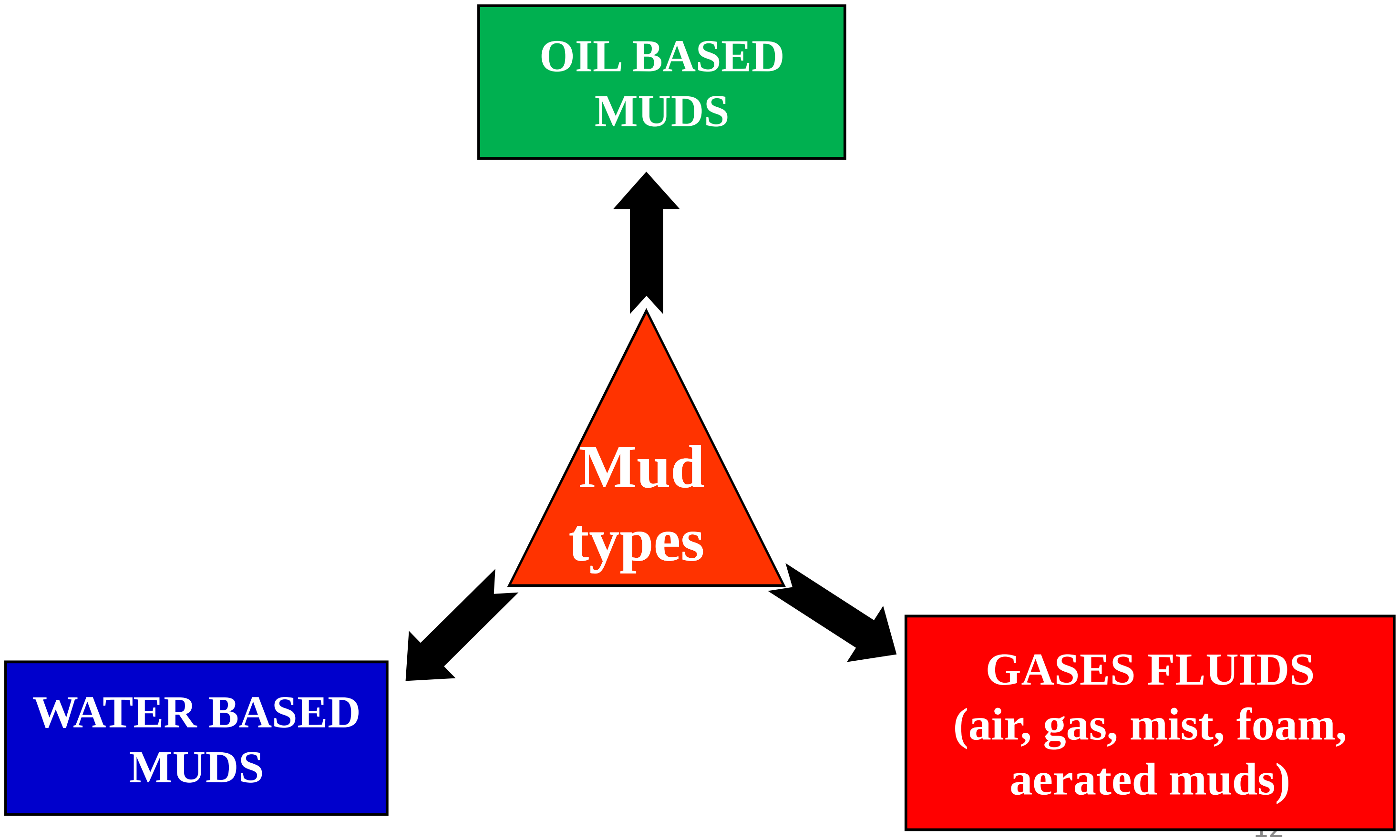
Weighting material additives

Material	Principal Component	Specific Gravity	%Acid Soluble
Galena	PbS	7.4-7.7	0
Haematite	Fe_2O_3	4.9-5.3	50+
Magnetite	Fe_3O_4	5.0-5.2	0
Illmenite	$FeO.TiO_2$	4.5-5.1	20
Barite	$BaSO_4$	4.2-4.6	0
Siderite	$FeCO_3$	3.7-3.9	95+
Celestite	$SrSO_4$	3.7-3.9	0
Dolomite	$CaCO_3.MgCO_3$	2.8-2.9	99
Calcium Carbonate	$CaCO_3$	2.6-2.8	99

Viscosifier additives

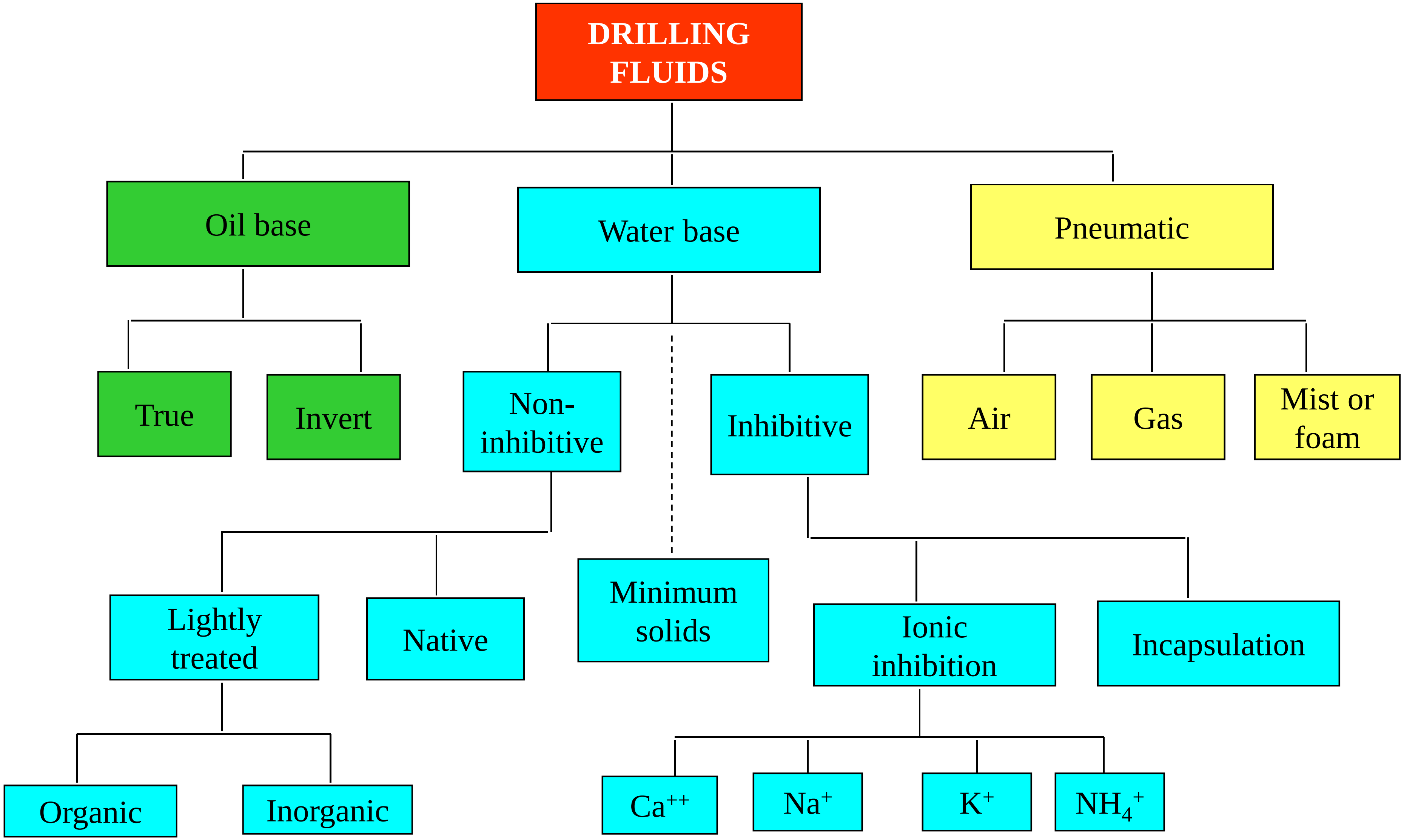
Material	Principal Component
Bentonite	Sodium/Calcium Aluminosilicate
CMC	Sodium Carboxy-methyle cellulose
PAC	Poly anionic Cellulose
Xanthan Gum	Extracellullar Microbial Polysaccharide
HEC	Hyroxy-ethyl Cellulose
Guar Gum	Hydrophilic Polysaccharide Gum
Resins	Hydrocarbon co-polymers
Silicates	Mixed Metal Silicates
Synthetic Polymers	High molecular weight Polyacrylamides/polyacrylates

Types of mud


OIL BASED MUDS
Mud types
WATER BASED MUDS
GASES FLUIDS (air, gas, mist, foam, aerated muds)

Classification of drilling fluids

(after IMCO Petroleum Services)



Classification of drilling fluids

(after API, "Principle of Drilling Fluids Control", 1972, p. 67)

A. Water-base drilling muds

- Fresh-water muds (little or no chemical treatment)
  1. Inhibited muds
  2. Spud muds
  3. Natural muds
- Chemically-treated muds (no calcium compounds added)
  1. Phosphate muds
  2. Organic-treated muds
     a. Lignite
     b. Quebracho and other extracts
     c. Chrome-lignosulfonate
- Calcium-treated muds
  1. Lime
  2. Calcium chloride
  3. Gypsum

Classification of drilling fluids (ctd)

(after API, “Principle of Drilling Fluids Control”, 1972, p. 67)

- Salt-water muds
  1. Sea-water muds
  2. Saturated salt-water muds
- Oil-emulsion muds (oil-in-water)
- Special muds
  1. Low-solids oil-emulsion muds
  2. Low-clay-solids weighted muds
  3. Surfactant muds
  4. Low-solids muds
     a. Clear water
     b. Polymer muds
     c. Low-solids, non-dispersed muds

Classification of drilling fluids (ctd)

(after API, "Principle of Drilling Fluids Control", 1972, p. 67)

B. Oil-base drilling muds

- Oil-base muds
- Invert emulsion muds (water-in-oil)

C. Gaseous drilling fluids

- Air or natural gas
- Aerated muds
- Foams

A. WATER-BASE MUDS

- Most widely used
- Consist of :
  - Liquid phase (e.g. water, emulsion)
  - Colloidal phase (e.g. clays)
  - Inert phase (e.g. barite, sand)
  - Chemical phase

Inhibited muds

- A mud having an aqueous base with a chemical composition that tends to retard or prevent (inhibit) appreciable hydration (swelling) or dispersion of formation clays & shales through chemical and/or physical means
- Includes salt-water muds, chrome lignosulfonate muds, surfactant treated muds, etc.

Spud muds

- The characteristics of the mud used for spudding-in (to start the hole) a well vary widely over the world (some locations are spudded-in in through conductor pipe already cemented in the cellar & some locations require that the length of the kelly & a few joints of drill pipe be drilled down in order to cement one or more joints of conductor casing)

Natural muds

- Composed of water & clays from the formation drilled, with little chemical treatment & with minor amounts of bentonite or other clays added
- Usually used to drill the surface hole & for fast drilling below the surface casing
- In most cases, the natural muds will be chemically treated as the depth of the well increases & will become one of the chemically treated muds discussed below.

Phosphate-treated muds

- For relatively shallow wells (7,500´ or less)

  $\rightarrow$ cannot with stand temperatures > 180°F & not effective when the mud is contaminated by salt or calcium
- Complex phosphates are very effective in reducing the μ, gel strength & filtration rate

Wood & bark extract treated muds

- Treatment of natural mud with caustic soda & quebracho extract was once widely practiced (particularly in the 1940 - 50 period)
- Gives pH of 10 - 12
- Other types of organic treatment, however, have now largely replaced the caustic-quebracho treatment e.g. modified hemlock bark extracts

Chrome lignosulfonate muds

- Used to minimize shale problems
- Can be used in high T wells e.g. up to 400 °F.

Calsium treated muds

- Tends to inhibit the swelling of clays & shale
  $\rightarrow$ Control sloughing & hole enlargement,
  excessive μ increase
- The most serious problem with Ca treated muds was severe gelation with time at high temperatures & high pH

Saltwater muds

- If chlorite ion > 1% (6,000 ppm)
  →salt water .
- Bentonite & clays hydrate less when added to water containing >1% salt.

Seawater muds

- On offshore & buy location, fresh water is sometimes not available for mixing water
- Sea water contains Na, Ca, Mg ions.

Oil-emulsion muds

- Oil was mixed so that the oil is suspended as individual droplets in the water phase.
- The emulsion must be stable → to prevent the oil from suspended at top → add emulsifier.
- Advantages :
  1. Improved hole condition
  2. Increased bit life
  3. Increased drilling rate

Surfactant muds

- Surface acting agent i.e. a material capable of acting upon the surface of a material
- Mud types:
  - Calcium surfactant
  - Low sodium surfactant
  - Saturated salt surfactant
  - Sea water surfactant

The pH of common mud treating agents

Chemical Name	pH
Barium carbonate, $BaCO_3$	10.0
Sodium bicarbonate, $NaHCO_3$, baking soda	8.3
Calcium sulfate, $CaSO_4.1/2\ H_2O$, gypsum-plaster	6.0
Chrome lignosulfonate	3.4 – 4.0
Sodium carbonate, Na_2CO_3, soda ash	11.0
Calcium hydroxide, $Ca(OH)_2$, slaked lime	12.0
Sodium hydroxide, NaOH, caustic soda	13.0
Calcium lignosulfonate	7.0
Lignite	5.0
Quebracho	3.8
Sodium acid pyrophosphate, $Na_2H_2P_2O_7$	4.8
Sodium hexametaphosphate, $(NaPO_3)_6$	6.0
Sodium tetraphosphate, $Na_6P_4O_{13}$	7.5
Tetrasodium pyrophosphate, $Na_4P_2O_7$	9.9

B. OIL BASE & INVERT EMULSION MUDS

- Oil is the continuous liquid phase (e.g. diesel)
- For safety, flash point must be > 150 °F
- Application:
  - protection of producing formations
  - drilling deep, hot holes
  - preventing differential P sticking
  - coring
  - packer fluids & casing packs
  - mitigating severe drill string corrosion
  - drilling troublesome shale

Why use oil based muds?

Advantages:

- Good rheological properties at temperatures as high as 500 ^{o}F (especially deeper well)
- More inhibitive than inhibitive WBMs
- Effective against all types of corrosion
- Superior lubricating characteristics
- Increase bit life & improve penetration rate
- Permits ρ_m as low as 7.5 ppg
- Reduce formation damage

Disadvantages:

- High initial cost
- Requires more stringent pollution-control procedures
- Reduced effectiveness of some logging tools
- Remedial treatment for lost circulation is more difficult
- Detection of gas kicks is more difficult because gas solubility in diesel oil

Why use ester based drilling fluids?

- Advantages:
  - Environmental friendly
  - Biodegradable
  - Local product-derived from palm oil
- Limitations:
  - Suitability/properties
  - High cost

C. GASES FLUIDS

(air, gas, mist, foam, aerated muds)

- Why gases are used?

  → lowest ρ: to prevent from damage & lost circulation

- Air drilling :

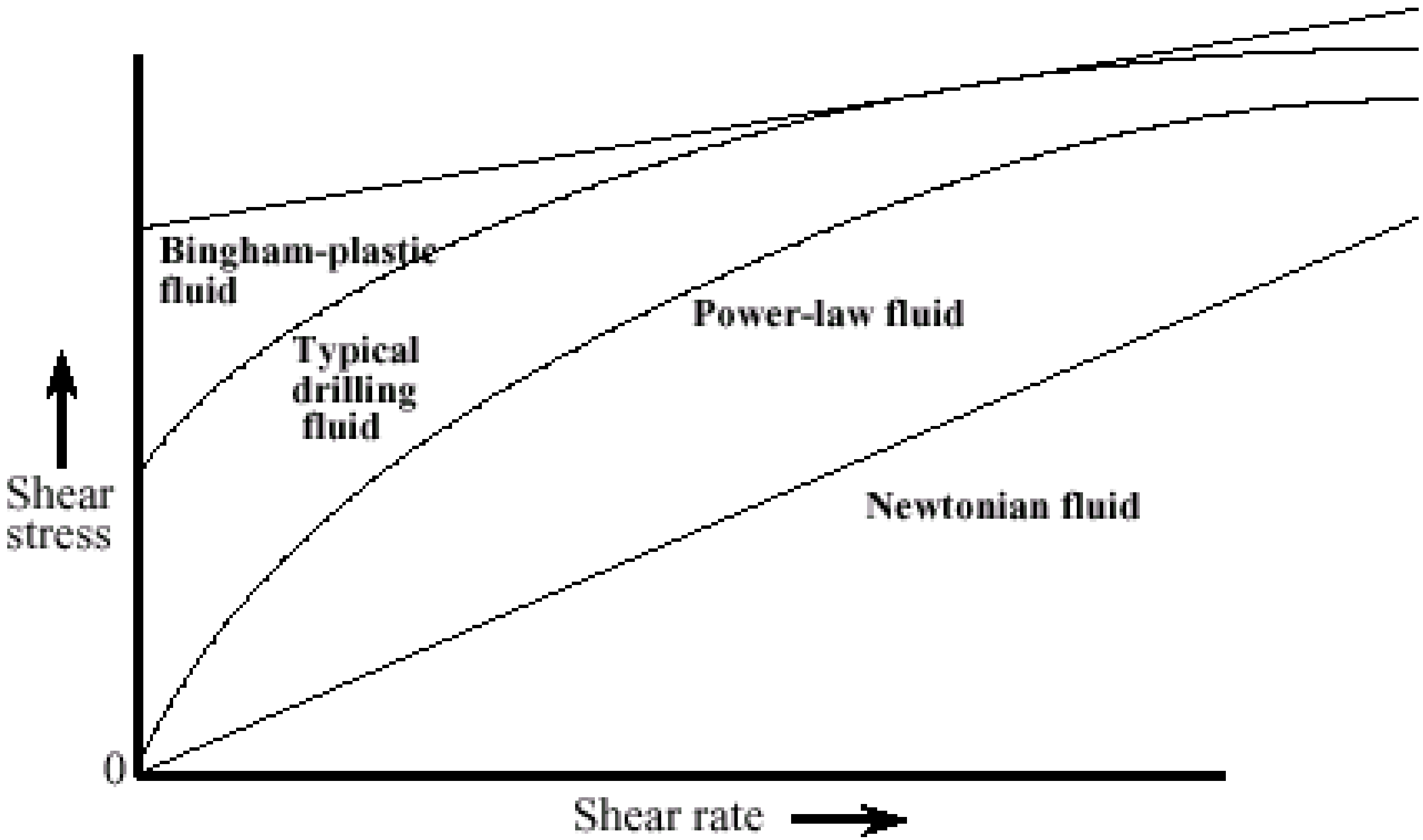
  a. Dry drilling or dusting

  b. Mist or foam drilling: water or a special mud is injected with a foaming agent into the air stream

  c. Stable foam drilling

  d. Aerated mud drilling

Rheological models



Mud properties

- Density (mud weight)
- Viscosity
- Gel strength
- Filtration
- Mud cake
- Emulsion stability
- Resistivity
- pH
- Lubricity
- Etc.

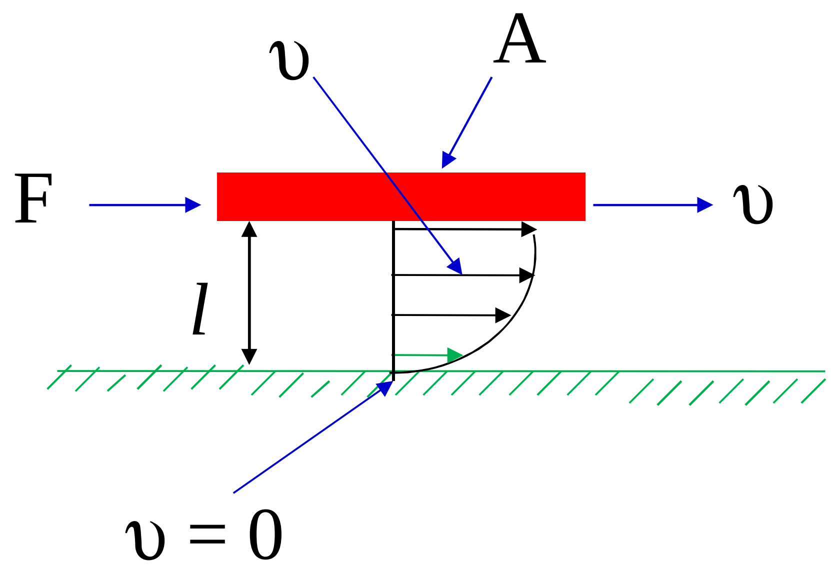
Standard drilling fluids testing:

- API RP 13B-1 (Recommended Practice for Field Testing Water-Based Drilling Fluids
- API RP 13B-2 (Recommended Practice for Field Testing Oil-Based Drilling Fluids

Density or mud weight

- (ppg, lb/cuft, S.G., ppb, psi/1000´)
- Mud balance → calibrated at 8.33 ppg (water) or 62.4 lb/cuft or 1.0 g/cc

Viscosity

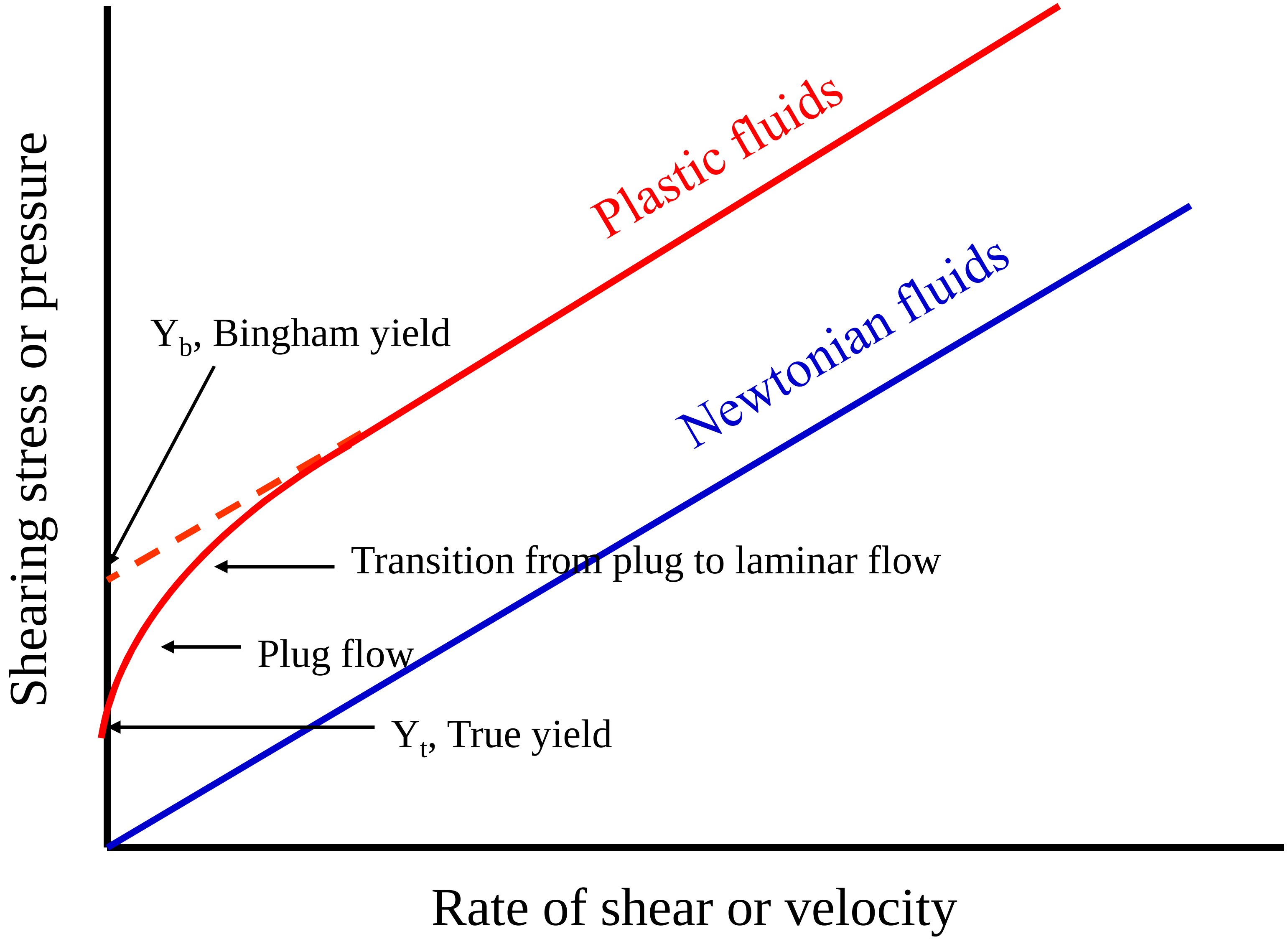


$$\mu = \frac{\text{shearing stress}}{\text{rate of shearing strain}} = \frac{F/A}{\upsilon/l} = \frac{\frac{ML/T^2}{L^2}}{\frac{L/T}{L}} = \frac{M}{LT}$$

- Water, oil, etc: Newtonian fluids (constant μ)
- Drilling fluids: Plastic or non-Newtonian fluids (μ is not constant)

  $\rightarrow$ certain value of stress (true yield point) must be exceeded in order to initiate movement

Flow behavior of plastic and Newtonian fluids



(a) Marsh funnel

- The funnel is filled to the upper mark (1500 cc) with freshly collected, well agitated mud
- Measures the time for 1 quart (946 cc)

  → comparative
- Calibration: 26 ± 0.5 sec. (water)

(b) Rheometer

- Determine: μ_a , μ_p , Y_b , gel or shear strength

$$\mu_p = \Phi_{600} - \Phi_{300} \quad \text{cp}$$

$$\mu_a = \tfrac{1}{2}\,\Phi_{600} \quad \text{cp}$$

$$Y_b = \Phi_{300} - \mu_p \quad \text{lb/100 ft}^2$$

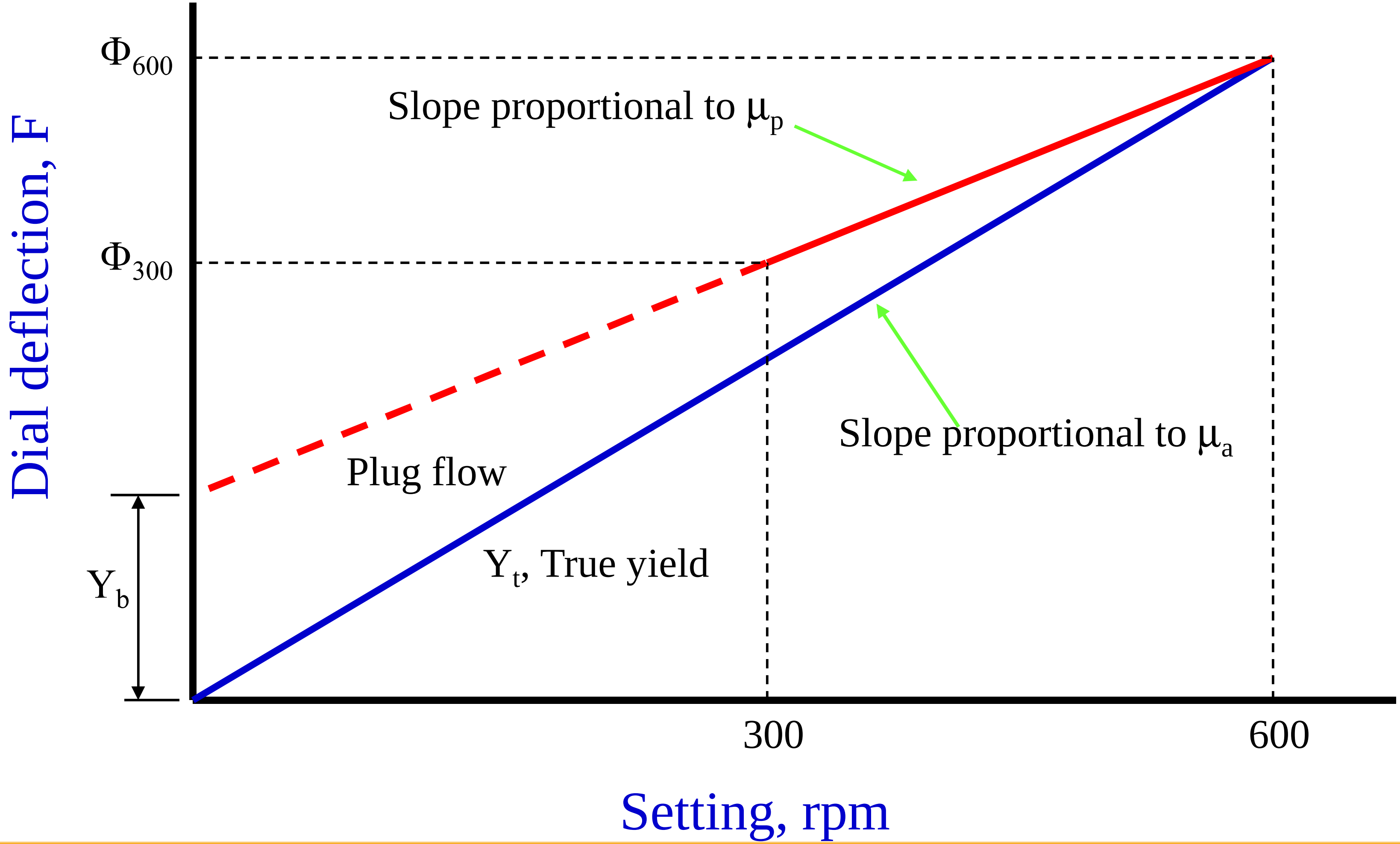
- From these relationships:

$$Y_b = 2(\mu_a - \mu_p) \quad \text{or}$$

$$\mu_a = \mu_p + \tfrac{1}{2}\,Y_b$$

- True yield point (from previous graph) is normally defined by the following equation:

$$Y_t = 3/4 \; Y_b$$



Gel strength

- A measure of the shearing stress necessary to initiate a finite rate of shear
- Measured at 3 rpm using rheometer
- Reported as initial gel strength (10 sec.) & final gel strength (10 min.)

Filtration properties

- Filter press: measure the filtration, water loss & mud cake thickness
- Using 100 psig, filter paper
- Filtrate volume: cc/30 min.
- Mud cake thickness: /32 in.
- In field testing, it is common practice to double the 7 ½ min. filtration loss & report this as the 30 min. figure

- This procedure is based on the observation that:

$$V_2 = V_1 \sqrt{t_2 / t_1}$$

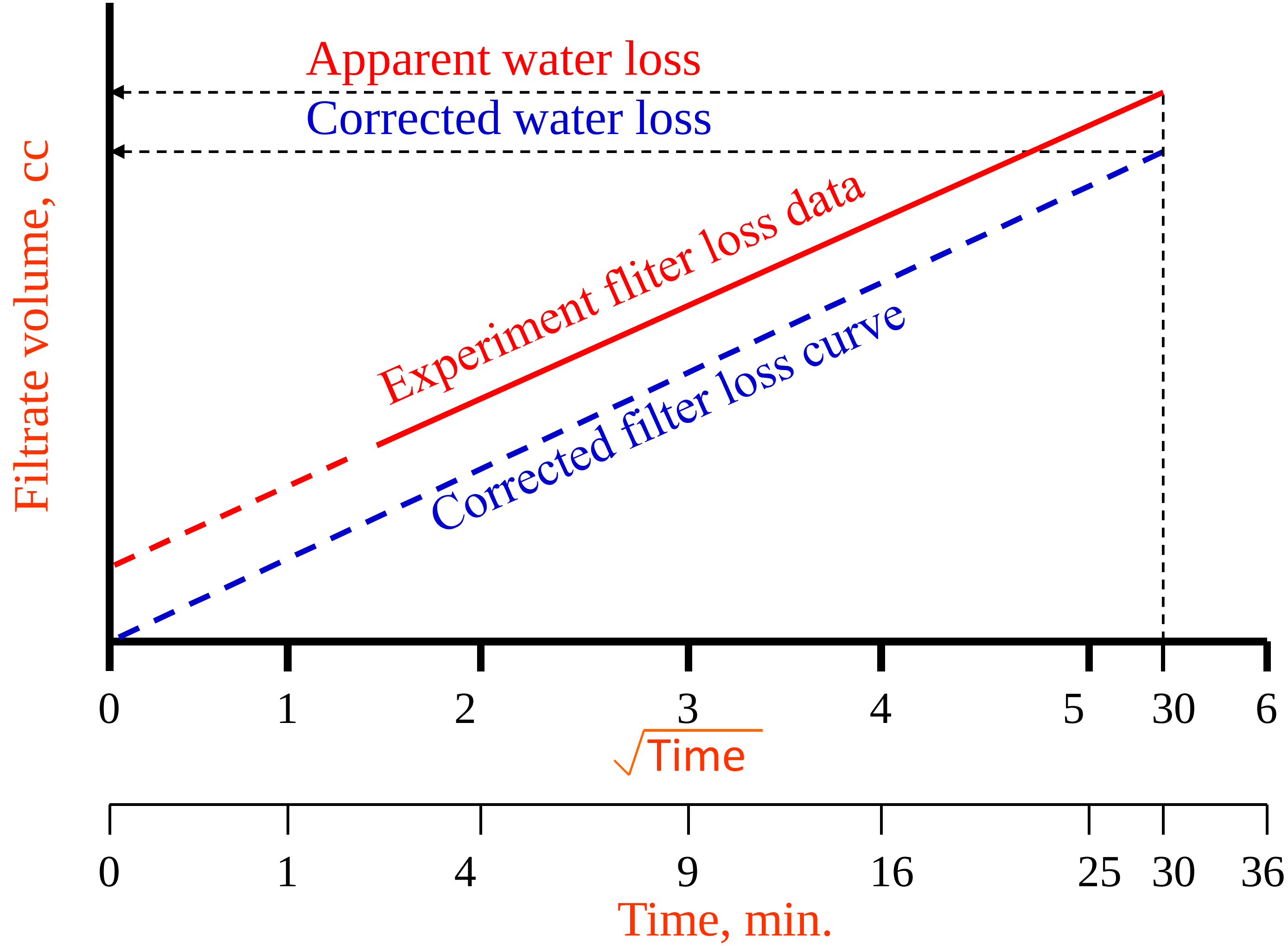
where: V_2 = filter loss at t_2, cc

V_1 = filter loss at t_1, cc

t_1, t_2 = filtration time, min.

- This procedure does not account for the initial spurt (high filter loss) period which occurs before the mud solid bridge on the filter paper

For some muds the spurt loss may be considerable volume and should be corrected as follows:



- Filtration loss may be corrected for T changes by:

$$V_2 = V_1 \sqrt{\mu_1 / \mu_2}$$

where:
V_2 = corrected water loss at T_2
V_1 = measured water loss at T_1
μ_1 = viscosity of liquid phase at T_1
μ_2 = viscosity of liquid phase at T_2
T_1, T_2 = temperatures in question

Other mud tests

TEST	APPARATUS	PURPOSE
pH	pH paper or pH meter	Guide to chemical treatment (to measure pH of whole mud, filtrate, and filter cake)
Filtrate analysis	Standard chemicals such as acid, indicators, etc.	Determination of contaminant to select chemical treatment
Sand content	Screens, measuring tube, centrifuge	Determination of sand content in the mud to prevent abrasion of pump & drill pipe
Oil, water, solids content	Distillation kit	Guide to control the desired properties (to determine oil, water & solid content)
Clay content	Methylene blue test	To determine the amount of clay materials in WBM
Emulsion stability	Electrical stability tester	To indicate the relative strength of emulsions having a continuous oil phase
Lubricity	Lubricity tester	To measure the lubricity of the muds
Resistivity	Resistivity meter	To measure resistivity of muds, filtrates, filter cakes, and slurries

The pH of Common Mud Treating Agents

Chemical Name	pH
Barium carbonate, $BaCO_3$	10.0
Sodium bicarbonate, $NaHCO_3$, baking soda	8.3
Calcium sulfate, $CaSO_4.1/2H_2O$, gypsum-plaster	6.0
Chrome lignosulfonates	3.4 – 4.0
Sodium carbonate, Na_2CO_3, soda ash	11.0
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Why monitor drilling fluids ?

- To identify potential hole problems
- To identify their causes
  - could be poor hole cleaning
  - hole erosion
  - formation damage
  - sensitive formations
  - pressure control problems

Mud Properties

Properties	The Importance
Density	➢ Pressure control → Δp = ± 200 psi (overbalance) $p_m = \frac{\rho_m}{8.33} \text{ X } 0.433\, D = 0.052 \rho_m D$
Mud Filtrate	➢ Mud ability to form a thinner mud cake with low permeability on the wall of porous medium. ➢ Thicker mud cake means more solid materials settled at formation wall and more filtration lost to the formation. ➢ Thicker mud cake easier to collapse and cause other problem during drilling activity such as the hole becomes smaller.
Gel Strength	➢ The ability of mud to suspend solids (especially weighting materials, drilled cuttings). ➢ Very important in suspended drilling operation.
Yield Point	➢ The amount of pressure (shearing stress) needed to be applied to flow the mud. ➢ Very important in determining pump capacity and the amount of pressure needed to be applied to flow the mud from static positions.
Gel strength + Yield Point	➢ Carrying capacity of the mud.
Thinner	➢ The reduce mud viscosity (Y_b, μ_a, gel strength) without reducing the mud density.
Weighting Materials	➢ The increase mud density without causing any reaction in the mud (inert materials).

Mud Selection Criteria

Criteria		Comments
Well type	Wildcat	Geological information is primary consideration.
	Development	Generally allow full use of optimized techniques.
Formation	Sloughing shale	Formulate fluid to control sloughing.
	Anhydrite	If minor, treat out calcium; massive anhydrite requires specialized mud
	Salt	If salt contamination exceeds 10,000 ppm, a salt-based mud is required
High temperatures		Static BHT above 225°F reduces effectiveness of additive, problem magnified by high clay-solids content
Lost circulation		Batch treatment successful for minor or intermediate losses; special technique required for major losses
Makeup water	Composition	Test and treat makeup water to remove calcium and magnesium; use flocculants to remove clay solids
	Availability	Quantity and type are important in fluid selection
Rig selection		Rigs should have proper solids-removal equipment and adequate circulating horsepower.
Nature of producing formations		Type of fluid selected is dependent on rock characteristic of reservoir.
Casing program		Drilling fluid(s) used may be determined by casing string depths.
Availability of products		In remote, international areas, drilling fluid type may depend on product availability.

Drilling Fluids Mistakes

- Not testing the quality of the make-up water & treating it properly
- Mixing the additives too rapidly or in an incorrect order
- Not matching the correct drilling fluid with soil type
- Mixing too low of a concentration of additives to allow them to perform properly
- Failure to maintain slurry flow throughout the bore
- Failure to calculate the volumes of water & additives that are required
- Failure to calculate the drilling/reaming speeds so as not to outrun fluid flow
- Poor bore planning
- Not calculating pullback rates vs. pump volume output
- Thinking that loss of fluid returns will not lead to problems
- Ignoring the importance of mud reclaiming systems and maintenance

Converting field unit to laboratory unit (ppb to g/cc)

$$1\ \frac{lb}{bbl} = 1\ \frac{lb}{bbl} \times \frac{454\ \dfrac{g}{lb}}{42\ \dfrac{gal}{bbl} \times 3785\ \dfrac{cc}{gal}} = \frac{g}{350\ cc}$$

$$\therefore\ \frac{lb}{bbl} = \frac{g}{350\ cc}$$

$$e.g.\ \ 12\ \ ppb = 12\ \ g\,/\,350\ \ cc$$