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**Petroleum and natural gas industries —  
Drilling fluids — Processing equipment  
evaluation**

*Industries du pétrole et du gaz naturel — Fluides de forage —  
Évaluation des équipements de traitement*

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## Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 2.

The main task of technical committees is to prepare International Standards. Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights.

ISO 13501 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries*, Subcommittee SC 3, *Drilling and completion fluids, and well cements*.

This second edition cancels and replaces the first edition (ISO 13501:2005), which has been technically revised.

The main changes compared with the first edition are as follows:

- Clause 11 specifies a different labelling requirement for shale shaker screens that are permanently attached to the screen, and also covers the marking of shipping containers for shale shaker screens;
- Annex B describes a standard procedure for the quick assessment of a solids control screen sizing, which can be used in the field or laboratory for identification of an unknown screen approximate size range.

NOTE The procedure described in Annex B is provided for information only and does not replace or supplement the normative testing in accordance with Clauses 9, 10 and 11, nor is it intended for the operating comparison or ranking of similar types of individual pieces of equipment.

## Introduction

This International Standard is based on API RP 13C, 3rd edition, December 2004 (for drilling fluid processing equipment) and shale shaker screen API RP 13E, 3rd edition, May 1993 (for shale shaker screens).

The purpose of this International Standard is to provide a method of assessing the performance of solids control equipment systems in the field. It includes procedures for evaluation of shale shakers, centrifugal pumps, degassers, hydrocyclones, mud cleaners and centrifuges, as well as an entire system evaluation. Shale shaker screen labelling and separation potential of shale shaker screens have been addressed within this International Standard.

This International Standard covers equipment which is commonly used in petroleum and natural gas drilling fluids processing. This equipment can be purchased or rented from multiple sources, and is available worldwide. No single-source or limited-source equipment is included, either by inference or reference.

In this International Standard, quantities expressed in the International System (SI) of units are also, where practical, expressed in United States Customary (USC) units for information.

NOTE The units do not necessarily represent a direct conversion of SI units to USC units, or of USC units to SI units.

Consideration has been given to the precision of the instrument making the measurement. For example, thermometers are typically marked in one degree increments, thus temperature values have been rounded to the nearest degree.

This International Standard refers to assuring the accuracy of the measurement. Accuracy is the degree of conformity of a measurement of a quantity to the actual or true value. Accuracy is related to precision, or reproducibility of a measurement. Precision is the degree to which further measurements or calculations will show the same or similar results. Precision is characterized in terms of the standard deviation of the measurement. The result of calculation or a measurement can be accurate, but not precise, precise but not accurate, neither or both. A result is valid if it is both accurate and precise.

Users of this International Standard should be aware that further or differing requirements may be needed for individual applications. This International Standard is not intended to inhibit a vendor from offering, or the purchaser from accepting, alternative equipment or engineering solutions for the individual application. This may be particularly applicable where there is innovative or developing technology. Where an alternative is offered, the vendor should identify any variations from this International Standard and provide details.

# Petroleum and natural gas industries — Drilling fluids — Processing equipment evaluation

## 1 Scope

This International Standard specifies a standard procedure for assessing and modifying the performance of solids control equipment systems commonly used in the field in petroleum and natural gas drilling fluids processing.

The procedure described in this International Standard is not intended for the comparison of similar types of individual pieces of equipment.

## 2 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 3310-1<sup>1)</sup>, *Test sieves — Technical requirements and testing — Part 1: Test sieves of metal wire cloth*

ISO 10414-1<sup>2)</sup>, *Petroleum and natural gas industries — Field testing of drilling fluids — Part 1: Water-based fluids*

ISO 10414-2<sup>3)</sup>, *Petroleum and natural gas industries — Field testing of drilling fluids — Part 2: Oil-based fluids*

ANSI/AWWA C700, *Cold-Water Meters — Displacement Type, Bronze Main Case*

API, *Manual of Petroleum Measurement Standards*

## 3 Terms, definitions, symbols and abbreviated terms

### 3.1 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

#### 3.1.1

##### addition section

compartment(s) in the surface drilling fluid system, between the removal section and the suction section, which provides (a) well-agitated compartment(s) for the addition of commercial products such as chemicals, necessary solids and liquids

- 
- 1) For the purposes of this International Standard, ASTM E11-95 is equivalent to ISO 3310-1.
  - 2) For the purposes of this International Standard, API RP 13B-1 is equivalent to ISO 10414-1.
  - 3) For the purposes of this International Standard, API RP 13B-2 is equivalent to ISO 10414-2.

**3.1.2**

**agitator  
mechanical stirrer**

mechanically driven mixer that stirs the drilling fluid, by turning an impeller near the bottom of a mud compartment to blend additives, suspend solids and maintain a uniform consistency of the drilling fluid

**3.1.3**

**aperture**

⟨screen cloth⟩ opening between the wires in a screen cloth

**3.1.4**

**aperture**

⟨screen surface⟩ opening in a screen surface

**3.1.5**

**apex**

opening at lower end of a hydrocyclone

**3.1.6**

**API sand**

⟨physical description⟩ particles in a drilling fluid that are too large to pass through a 74 µm sieve (API 200 screen)

NOTE 1 Its amount is expressed as a volume fraction (percent) of drilling fluid.

NOTE 2 Particle size is a descriptive term; the particles can be shale, limestone, wood, gold or any other material.

**3.1.7**

**API screen number**

number in an API system used to designate the D100 separation range of a mesh screen cloth

NOTE 1 Both mesh and mesh count are obsolete terms, and have been replaced by the API screen number.

NOTE 2 The term “mesh” was formerly used to refer to the number of openings (and fraction thereof) per linear inch in a screen, counted in both directions from the centre of a wire.

NOTE 3 The term “mesh count” was formerly used to describe the fineness of a square or rectangular mesh screen cloth, e.g. a mesh count such as 30 × 30 (or, often, 30 mesh) indicates a square mesh, while a designation such as 70 × 30 mesh indicates a rectangular mesh.

NOTE 4 See 9.6 for further information.

**3.1.8**

**backing plate**

support plate attached to the back of screen cloth(s)

**3.1.9**

**baffle**

plate or obstruction built into a compartment to change the direction of fluid flow

**3.1.10**

**barite**

**baryte**

natural barium sulfate (BaSO<sub>4</sub>) used for increasing the density of drilling fluids

NOTE The standard international requirement is for a minimum specific gravity of 4,20 or 4,10 for two grades of barite, but there is no specification that the material must be barium sulfate. Commercial ISO 13500 barite can be produced from a single ore or a blend of ores, and can be a straight-mined product or processed by flotation methods. It can contain accessory minerals other than barium sulfate (BaSO<sub>4</sub>). Because of mineral impurities, commercial barite can vary in colour from off-white to grey to red or brown. Common accessory minerals are silicates such as quartz and chert, carbonate compounds such as siderite and dolomite, and metallic oxide and sulfide compounds.

**3.1.11****blinding**

reduction of open area in a screening surface caused by coating or plugging

**3.1.12****bonding material**

material used to secure screen cloth to a backing plate or support screen

**3.1.13****capture**

mass fraction of incoming suspended solids that are conveyed to the reject stream

NOTE See Clause 6.

**3.1.14****centrifugal pump**

machine for moving fluid by spinning it using a rotating impeller in a casing with a central inlet and a tangential outlet

NOTE The path of the fluid is an increasing spiral from the inlet at the centre to the outlet, tangent to the impeller annulus. In the annular space between the impeller vane tips and the casing wall, the fluid velocity is roughly the same as that of the impeller vane tips. Useful work is produced by the pump when some of the spinning fluid flows out of the casing tangential outlet into the pipe system. Power from the motor is used to accelerate the fluid entering the inlet up to the speed of the fluid in the annulus. Some of the motor power is expended as friction of the fluid in the casing and impeller.

**3.1.15****centrifuge**

device, rotated by an external force, for the purpose of separating materials of various masses (depending upon specific gravity and particle sizes) from a slurry to which the rotation is imparted primarily by the rotating containing walls

NOTE In a weighted drilling fluid, a centrifuge is usually used to eliminate colloidal solids.

**3.1.16****check section****suction section**

last active section in the surface system which provides a location for rig pump and mud hopper suction, and ideally is large enough to check and adjust drilling fluid properties before the drilling fluid is pumped downhole

**3.1.17****clay mineral**

soft, variously coloured earth, commonly hydrous silicate of alumina

NOTE Clay minerals are essentially insoluble in water, but disperse under hydration, grinding, heating or velocity effects. Particle sizes of clay mineral can vary from sub-micrometre to larger than 100  $\mu\text{m}$ .

**3.1.18****clay particle**

colloidal particles of clay mineral having less than 2  $\mu\text{m}$  equivalent spherical diameter

NOTE See **colloidal solid** (3.1.21).

**3.1.19****coating**

(substance) material adhering to a surface to change the properties of the surface

NOTE See **blinding** (3.1.11).

**3.1.20  
coating**

(physical process) procedure by which material forms a film that covers the apertures of the screening surface

NOTE See **blinding** (3.1.11).

**3.1.21  
colloidal solid**

particle of diameter less than 2 µm

NOTE This term is commonly used as a synonym for clay particle size.

**3.1.22  
conductance**

permeability per unit thickness of a static (not in motion) shale shaker screen

NOTE Conductance is expressed in units of kilodarcies per millimetre<sup>4</sup>).

**3.1.23  
cuttings**

formation pieces dislodged by the drill bit and brought to the surface in the drilling fluid

NOTE Field practice is to refer to all solids removed by the shaker screen as "cuttings", although some can be sloughed material.

**3.1.24  
D100 separation**

particle size, expressed in micrometres, determined by plotting the percentage of aluminium oxide sample separated by the test screen on the plot of cumulative mass fraction (expressed as a percentage) retained versus US sieve opening (expressed in micrometres) for the sieve analysis of the aluminium oxide test sample

NOTE 100 % of the particles larger than the D100 separation are retained by the test screen.

**3.1.25  
decanting centrifuge**

centrifuge that removes solids from a feed slurry by rotating the liquid in cylindrical bowl at high speed and discharges the larger particles as a damp underflow

NOTE Colloidal solids are discharged with the liquid overflow or light slurry. The decanting centrifuge has an internal auger that moves solids that have settled to the bowl walls out of a pool of liquid and to the underflow.

**3.1.26  
density**

mass divided by volume

NOTE 1 In SI units, density is expressed in kilograms per cubic metre; in USC units, it is expressed as pounds per gallon or pounds per cubic foot.

NOTE 2 Drilling fluid density is commonly referred to as "drilling fluid weight" or "mud weight".

**3.1.27  
desander**

hydrocyclone with an inside diameter of at least 152 mm (6 in) that removes a high proportion of the particles with a diameter of at least 74 µm from a drilling fluid

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4) The darcy is not an SI unit, but kilodarcies per millimetre (kD/mm) is the recommended unit for this International Standard. The SI unit of permeability to fluid flow is defined as the amount of permeability that permits 1 m<sup>3</sup> of fluid of a viscosity of 1 Pa·s to flow through a section that is 1 m thick with a cross-section of 1 m<sup>2</sup> in 1 s at a pressure difference of 1 Pa. Therefore, in the SI system of units, permeability is expressed in square metres: 1 m<sup>2</sup> = 1,013 25 × 10<sup>12</sup> darcies.

**3.1.28****desilter**

hydrocyclone with an inside diameter of less than 152 mm (6 in)

**3.1.29****dilution**

method of decreasing the drilled-solids content of a slurry by addition of (a) material(s) other than drilled solids, usually a clean drilling fluid

**3.1.30****dilution factor**

*k*

ratio of the actual volume of clean drilling fluid required to maintain a targeted drilled-solids concentration to the volume of drilling fluid required to maintain the same drilled-solids fraction over the same specified interval of footage with no drilled-solids removal system

**3.1.31****drilled solids**

formation solids that enter the drilling fluid system, whether produced by the drill bit or from the side of the borehole

**3.1.32****drilled-solids fraction**

average volume fraction of drilled solids maintained in the drilling fluid over a specified interval of footage

**3.1.33****drilled-solids removal system**

equipment and processes used while drilling a well that remove the solids generated from the hole and carried by the drilling fluid

NOTE These processes include settling, screening, desanding, desilting, centrifuging and dumping.

**3.1.34****drilled-solids removal system performance**

measure of the removal of drilled solids by surface solids-control equipment

NOTE The calculation is based on a comparison of the dilution required to maintain the desired drilled-solids content with that which would have been required if none of the drilled solids were removed.

**3.1.35****drilling fluid**

liquid or slurry pumped down the drill string and up the annulus of a hole during the drilling operation

**3.1.36****eductor**

(fluid stream) device using a fluid stream that discharges under high pressure from a jet through an annular space to create a low-pressure region

NOTE When properly arranged, it can evacuate degassed drilling fluid from a vacuum-type degasser or pull solids through a hopper.

**3.1.37****eductor**

(pressure jet) device using a high-velocity jet to create a low-pressure region which draws liquid or dry material to be blended with the drilling fluid

NOTE The use of a high-velocity jet to create a low-pressure region is known as the Bernoulli principle.

**3.1.38**

**effluent**

discharge of liquid, generally a stream, after some attempt at separation or purification has been made

**3.1.39**

**equalizer**

opening for flow between compartments in a surface fluid-holding system, which allows all compartments to maintain the same fluid level

**3.1.40**

**flow capacity**

rate at which equipment, such as a shaker, can process drilling fluid and solids

NOTE It is a function of many variables, including shaker configuration, design and motion, drilling fluid rheology, solids loading, and blinding by near-size particles.

**3.1.41**

**flow line**

piping or trough which directs drilling fluid from the rotary nipple to the surface drilling fluid system

**3.1.42**

**flow rate**

volume of liquid or slurry that moves through a pipe in one unit of time

NOTE Flow rate is expressed as cubic metres per minute, gallons per minute, barrels per minute, etc.

**3.1.43**

**foam**

⟨phase system⟩ two-phase system, similar to an emulsion, in which the dispersed phase is air or gas

**3.1.44**

**foam**

⟨floating material⟩ bubbles floating on the surface of the drilling fluid

NOTE The bubbles are usually air-cut drilling fluid, but can be formation gasses.

**3.1.45**

**gumbo**

cuttings that agglomerate and form a sticky mass as they are circulated up the wellbore

**3.1.46**

**head**

height that a fluid column would reach in an open-ended pipe if the pipe were attached to the point of interest

NOTE The head at the bottom of a 300 m (1 000 ft) well is 300 m (1 000 ft), but the pressure at that point depends upon the density of the drilling fluid in the well.

**3.1.47**

**high specific gravity solids**

solids added to a drilling fluid specifically to increase drilling fluid density

NOTE Barite (specific gravity = 4,2) and haematite (specific gravity = 5,05) are the most common.

**3.1.48**

**hook strip**

hooks on the edge of a screen section of a shale shaker which accept the tension member for screen mounting

**3.1.49**  
**hopper**  
**mud hopper**

large, funnel-shaped or coned-shaped device, into which dry components are poured to mix the components uniformly with liquids or slurries that are flowing through the lower part of the cone

**3.1.50**  
**hydrocyclone**  
**cone**  
**cyclone**

liquid-solids separation device using centrifugal force for settling

NOTE Fluid enters tangentially and spins inside the hydrocyclone. The heavier solids settle to the walls of the hydrocyclone and move downward until they are discharged at the hydrocyclone apex. The spinning fluid travels part way down the hydrocyclone and back up to exit out the top of the hydrocyclone through a vortex finder.

**3.1.51**  
**impeller**

spinning disc in a centrifugal pump with protruding vanes, used to accelerate the fluid in the pump casing

**3.1.52**  
**manifold**

length of pipe with multiple connections for collecting or distributing drilling fluid

**3.1.53**  
**Marsh funnel viscosity**  
**funnel viscosity**

viscosity measured with the instrument used to monitor drilling fluid

NOTE 1 A Marsh funnel is a tapered container with a fixed orifice at the bottom so that, when filled with 1 500 cm<sup>3</sup> of fresh water, 946 cm<sup>3</sup> (one quart) will drain in 26 s. It is used for comparison values only and not to diagnose drilling fluid problems.

NOTE 2 See ISO 10414-1 or ISO 10414-2.

NOTE 3 For the purposes of this International Standard, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

**3.1.54**  
**mud**

slurry of insoluble and soluble solids in either water or a synthetic or oil continuous-phase fluid

NOTE See **drilling fluid** (3.1.35).

**3.1.55**  
**mud balance**

beam-type balance used in determining drilling fluid density

NOTE 1 See ISO 10414-1 or ISO 10414-2.

NOTE 2 For the purposes of this International Standard, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

**3.1.56**  
**mud cleaner**

combination of hydrocyclones and screens in series with the underflow of the hydrocyclones

NOTE The hydrocyclone overflow returns to the drilling fluid, while the underflow of the hydrocyclones is processed through a vibrating screen. The screen is usually of size API 150 or finer. The screen solids discharge is discarded while the liquid and solids passing through the screen are returned to the drilling fluid.

**3.1.57**

**mud compartment**

subdivision of the removal, addition or check/suction sections of a surface system

**3.1.58**

**mud gun**

submerged nozzle used to stir drilling fluid with a high-velocity stream

**3.1.59**

**near-size particle**

particle whose size is close to the size of the openings in the screen through which its passage is under evaluation

**3.1.60**

**oil-based drilling fluid**

drilling fluid in which the continuous phase is not miscible with water, and water or brine is the dispersed phase

NOTE Oil-based drilling fluids are usually referred to as non-aqueous drilling fluids, or NAF.

**3.1.61**

**overflow  
centrate**

discharge stream from a centrifugal separation that contains a higher percentage of liquids than the feed does

**3.1.62**

**particle**

discrete unit of solid material that consists of a single grain, or of any number of grains stuck together

**3.1.63**

**particle size distribution**

mass or net volume classification of solid particles into each of the various size ranges, as a percentage of the total solids of all sizes in a fluid sample

**3.1.64**

**plastic viscosity**

measure of the high-shear-rate viscosity, which depends upon the number, shape and size of solids and the viscosity of the liquid phase

NOTE 1 Plastic viscosity is calculated by subtracting the 300 r/min concentric cylinder viscometer reading from the 600 r/min concentric cylinder viscometer reading.

NOTE 2 See ISO 10414-1 or ISO 10414-2.

NOTE 3 For the purposes of this International Standard, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

NOTE 4 In SI units, plastic viscosity is expressed in pascal seconds; in USC units, plastic viscosity is expressed in centipoises.

**3.1.65**

**plugging**

wedging or jamming of openings in a screening surface by near-size particles, which prevents the passage of undersize particles and leads to the **blinding** (3.1.11) of the screen

**3.1.66**

**possum belly**

compartment or back tank on a shale shaker, into which the flow line discharges and from which drilling fluid is either fed to the screens or is bypassed, if necessary

**3.1.67****removal section**

first section in the surface drilling fluid system, consisting of a series of compartments to remove gas and undesirable solids

**3.1.68****retort**

instrument used to distil oil, water and other volatile material in a drilling fluid

NOTE 1 The amount of volatile fluid is used to determine oil, water and total solids contents as volume fraction percent, expressed as a percentage.

NOTE 2 See ISO 10414-1 or ISO 10414-2.

NOTE 3 For the purposes of this International Standard, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

**3.1.69****sand trap**

first compartment in a surface system, and the only compartment that is unstirred or unagitated, which is intended as a settling compartment

**3.1.70****screen cloth**

type of screening surface woven in square, rectangular or slotted openings

**3.1.71****screening**

mechanical process that results in a division of particles on the basis of size, based on their acceptance or rejection by a screening surface

**3.1.72****shale shaker**

mechanical device that separates cuttings and large solids from a drilling fluid

NOTE The separation methods can include vibrating screens, rotating cylindrical screens, etc.

**3.1.73****sieve**

laboratory screen with wire-mesh or electronically-punched holes of known dimensions

**3.1.74****sieve analysis**

classification by mass of solid particles passing through or retained on a sequence of screens with decreasing aperture sizes

NOTE Sieve analysis can be carried out by wet or dry methods.

**3.1.75****slug tank**

small compartment, normally adjacent to the suction compartment, used to mix special fluids to pump downhole

NOTE Slug tanks are most commonly used to prepare a small volume of weighted drilling fluid before a drillstring trip out of the borehole.

**3.1.76****suction compartment**

area of the check/suction section that supplies drilling fluid to the suction of the drilling fluid pumps

NOTE In general terms, a suction compartment is any compartment from which a pump removes fluid.

**3.1.77**

**sump**

pan or lower compartment below the lowest shale shaker screen

**3.1.78**

**tensioning**

stretching of a screening surface of a shale shaker to the proper tension, while positioning it within the vibrating frame

**3.1.79**

**total dilution**

volume of drilling fluid that would be built to maintain a specified volume fraction of drilled solids over a specified interval of footage, if there were no solids removal system

**3.1.80**

**total non-blanked area**

net unblocked area that permits the passage of fluid through a screen

NOTE 1 Total non-blanked area is expressed in square metres (square feet).

NOTE 2 Some screen designs can eliminate as much as 40 % of the gross screen panel area from fluid flow due to backing-plate and bonding-material blockage.

**3.1.81**

**trip tank**

gauged and calibrated vessel used to account for fill and displacement volumes as pipe is pulled from and run into the hole

NOTE Close observation allows early detection of formation fluid entering a wellbore and of drilling fluid loss to a formation.

**3.1.82**

**underflow**

(centrifugal separator) discharge stream from a centrifugal separator that contains a higher percentage of solids than the feed does

**3.1.83**

**underflow**

(screen separator) discharge stream from a screen separator that contains a lower percentage of solids than the feed does

**3.1.84**

**unoccluded**

unobstructed area of a screen opening

**3.1.85**

**unweighted drilling fluid**

drilling fluid that does not contain commercial suspended solids added for the purpose of increasing the density of the drilling fluid

**3.1.86**

**viscosity**

ratio of shear stress to shear rate

NOTE 1 In SI units, viscosity is expressed in pascal seconds; in USC units, viscosity is expressed in centipoises.

NOTE 2 If the shear stress is expressed in the centimetre-gram-second (CGS) system of units (dynes per square centimetre) and the shear rate is expressed in reciprocal seconds, the viscosity is expressed in poises (P).  
1 P = 1 dyn·s/cm<sup>2</sup> = 1 g·cm<sup>-1</sup>·s<sup>-1</sup> = 10<sup>-1</sup> Pa·s; 1cP = 1mPa·s.

**3.1.87****volume of solids drilled**

volume of solids drilled over a specified interval

**3.1.88****vortex**

cylindrical or conical shaped core of air or vapour that lies along the central axis of the rotating slurry inside a hydrocyclone

**3.1.89****water-based drilling fluid**

drilling fluid in which water is the suspending medium for solids and is the continuous phase, whether oil is present or not

**3.1.90****weighted drilling fluid**

drilling fluid to which solids have been added in order to increase its density

**3.1.91****weighting material**

solids used to increase the density of drilling fluids

NOTE This material is commonly barite or haematite; in special applications, it might be limestone.

**3.2 Symbols and abbreviated terms****3.2.1 Symbols**

$A$	cross-sectional area, expressed in square centimetres
$C$	conductance of screen cloth, expressed in kilodarcies per millimetre
$h$	head, expressed in metres
$h_T$	head for testing, expressed in millimetres (inches)
$k$	dilution factor
$K$	constant of proportionality, or permeability, expressed in darcies
$L$	length of the porous medium, expressed in centimetres
$m_1$	mass of empty container, expressed in grams
$m_2$	mass of container plus sample, expressed in grams
$m_3$	mass of dried/retorted container, expressed in grams
$m_S$	sample mass
$p$	pressure, expressed in kilopascals
$\Delta p$	pressure differential, expressed in atmospheres
$q$	flow rate through a porous medium, expressed in cubic centimetres per second
$V_a$	volume of total drilling fluid system, expressed in cubic metres (gallons)

- $V_b$  volume of base fluid added to drilling fluid system, expressed in cubic metres (gallons)
- $V_c$  volume of drilling fluid built, expressed in cubic metres (gallons)
- $V_d$  volume of solids drilled, expressed in cubic metres (gallons)
- $V_e$  volume of total dilution, expressed in cubic metres (gallons)
- $V/t$  flow rate (volume per time), expressed in  $m^3/h$ , (gal/min)
- $w$  mass fraction, expressed as a decimal fraction
- $w_a$  mass fraction of suspended solids removed, expressed as a percentage
- $w_1$  mass fraction of suspended solids in the feed to a piece of separator equipment, expressed as a decimal fraction
- $w_2$  mass fraction of suspended solids in the overflow from a piece of separator equipment, expressed as a decimal fraction
- $w_3$  mass fraction of suspended solids in the underflow from a piece of separator equipment, expressed as a decimal fraction
- $w_4$  mass fraction of weighting material, expressed as a decimal fraction
- $w_5$  mass fraction of low-gravity solids, expressed as a percentage
- $\eta$  efficiency, drilled-solids removal system performance
- $\varphi_a$  base fluid volume fraction of total drilling fluid system,  $V_a$ , determined by retort and salinity measurement, expressed as a percentage
- $\varphi_b$  drilled-solids volume fraction of total drilling fluid system,  $V_a$ , determined by retort, salinity and bentonite measurement, expressed as a percentage
- $\mu$  fluid viscosity, expressed in centipoises
- $\rho$  density of oil or drilling fluid, expressed in  $kg/m^3$  (lb/gal, lb/ft<sup>3</sup>)
- $\rho_1$  specific gravity of separated solids (see 6.7 and 6.8)
- $\rho_2$  specific gravity of weighting material (see 6.7 and 6.8)

### 3.2.2 Abbreviated terms

- ACS American Chemical Society
- AIO aluminium oxide ( $Al_2O_3$ ) with a specific gravity of 3,5 to 3,9
- API American Petroleum Institute
- ASTM American Society of Testing Materials
- AWWA American Water Works Association
- CAS Chemical Abstracting Services (division of ACS)

PVC	polyvinyl chloride
SI	International System (of units)
USC	United States Customary (of units)

## 4 Requirements

**4.1** This International Standard is organized such that a method of assessing the performance of an equipment set is presented first. A procedure for assessing the performance of individual equipment pieces is then presented. A collection of proven operating guidelines for the equipment and the overall system is then given. The principles shall be used to design a new system or to modify the operation of the equipment and removal system on an existing drilling rig, and thereby comply with this International Standard.

**4.2** Use of this practice allows direct comparison of the results achieved by modifications made to the system at the drill site. Improved removal performance can be recognized through lower trouble costs and improved drilling performance.

**4.3** Shale shaker screen designations and labelling are included as a means for manufacturers to mark screens in a consistent manner. The screen identification tag describes the equivalent screen aperture opening, the conductance and the non-blanked area of the screen. Screen manufacturers shall use this designation to comply with this International Standard.

## 5 System performance of drilled-solids removal

### 5.1 Principle

**5.1.1** This procedure provides a method for determining drilled-solids removal efficiency by a set of drilling fluid processing equipment.

**5.1.2** The drilled-solids removal efficiency refers to the volume fraction of drilled rock discarded compared with the volume of drilled solids generated.

**5.1.3** Dumping drilling fluid removes 100 % of the drilled solids but is not a desirable removal method because of the amount of drilling fluid lost. The solids removal efficiency refers to the ability of the equipment to reduce the concentration of drilled solids in the system. Dumping drilling fluid does not reduce the concentration of drilled solids in the system.

**5.1.4** The dilution factor,  $k$ , describes the **drilled-solids removal system performance** (see definitions 3.1.30, 3.1.33 and 3.1.34). The processes involved consist of removing whole drilling fluid (including lost circulation), settling, screening, desanding, desilting and centrifuging. The dilution factor is calculated by monitoring the amount of base fluid (oil or water) added to the system and/or the volume of clean drilling fluid added to the system to dilute the remaining drilled solids after processing the drilling fluid through the solids control equipment.

### 5.2 Apparatus

#### 5.2.1 Meters:

- a) Water meters shall comply with AWWA standard C705, as referenced in ANSI/AWWA C700.
- b) Metering of oils shall be carried out in accordance with the *API Manual of Petroleum Measurement Standards*, Chapter 5. Turbine meter operation is contained in Section 3.

**5.2.2 Drilling fluid density determination apparatus**, of sufficient accuracy to permit measurement within  $\pm 0,01 \text{ g/cm}^3$  or  $\pm 10 \text{ kg/m}^3$  (0,1 lb/gal, 0,5 lb/ft<sup>3</sup>).

## ISO 13501:2011(E)

The mud balance is the instrument generally used for drilling fluid density determinations. The mud balance and procedures are described in ISO 10414-1 or ISO 10414-2.

NOTE For the purposes of this provision, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

**5.2.3 Apparatus for water, oil and solids determination**, as described in ISO 10414-1 or ISO 10414-2.

NOTE For the purposes of this provision, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

**5.2.3.1 Retort instrument.**

**5.2.3.2 Liquid receiver.**

**5.2.3.3 Fine steel wool.**

**5.2.3.4 High-temperature-resistant silicone grease.**

**5.2.3.5 Pipe cleaners.**

**5.2.3.6 Putty knife or spatula.**

**5.2.3.7 Defoaming agent.**

**5.2.4 Chloride (salinity) determination apparatus**, as described in ISO 10414-1 for water-based fluids, or in ISO 10414-2 for oil-based fluids.

NOTE For the purposes of this provision, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

**5.2.4.1 Silver nitrate solution**, 47,91 g/l stored in an amber or opaque bottle (CAS No. 7761-88-8).

**5.2.4.2 Potassium chromate indicator solution**, 5 g/100 cm<sup>3</sup> (CAS No. 7778-50-9).

**5.2.4.3 Sulfuric or nitric acid solution**, standardized 0,05 mol/l [0,02 N (N/50)] (CAS No. 7665-93-9 or CAS No. 7697-37-2).

**5.2.4.4 Phenolphthalein indicator solution**, 1 g/100 cm<sup>3</sup> of 50 % alcohol in water solution (CAS No. 77-09-8).

**5.2.4.5 Calcium carbonate**, precipitated, chemically pure grade (CAS No. 471-34-1).

**5.2.4.6 Distilled water.**

**5.2.4.7 Serological (graduated) pipettes**, one of capacity 1 cm<sup>3</sup> and one of capacity 10 cm<sup>3</sup>.

**5.2.4.8 Titrating vessel**, of capacity 100 cm<sup>3</sup> to 150 cm<sup>3</sup>, white beaker preferably.

**5.2.4.9 Stirring rod.**

## 5.3 Sampling

**5.3.1** Remove a 1 l (1 qt) sample of drilling fluid from the suction pit following all processing by solids control equipment.

**5.3.2** Clear the sample of any foreign objects, such as leaves or twigs.

**5.3.3** Record the well depth or interval at which the measurement is being made.

## 5.4 Procedure

### 5.4.1 Suction pit drilling fluid density chloride content, and solids by retort

Measure and record the drilling fluid density, chloride content and solids by retort in accordance with procedures outlined in ISO 10414-1 for water-based drilling fluids, or in ISO 10414-2 for oil-based drilling fluids.

NOTE For the purposes of this provision, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

### 5.4.2 Base fluid additions to the drilling fluid

**5.4.2.1** Metering devices can provide the actual volume of base fluid used within the accuracy of the equipment. The most commonly used meters for measuring base fluid consumption are the mechanical turbine propeller and compound types.

**5.4.2.2** Magnetic and Doppler meters are more dependent on suspended solids in fluid streams to provide volume measurements.

**5.4.2.3** The sizing of the meter is critical for accuracy. Tables of acceptable line sizes per volume throughput are included in the ANSI/AWWA C700 series of standards. These standards are meter body type specific, so a knowledge of the meter composition is required. The test for all meters should be volumetric or by mass, if accurate scales are available.

**5.4.2.4** Use strainers upstream of the meter and check frequently for clogging.

**5.4.2.5** Record the volume of base fluid added to the drilling fluid system as  $V_b$ . The recorded value shall be within 0,25 % (volume fraction) of the actual volume.

### 5.4.3 Base fluid fraction

The base fluid fraction is the average value for the interval in question. The averaging method is critical. It is important to use the same method to enable interval and well comparisons.

Using different averaging methods can result in inaccurate comparisons. The base fluid fraction can be calculated from solids analysis methods using retort and salinity measurements, as outlined in ISO 10414-1 or ISO 10414-2.

NOTE For the purposes of this provision, API RP 13B-1 is equivalent to ISO 10414-1 and API RP 13B-2 is equivalent to ISO 10414-2.

Record the base fluid fraction as  $\varphi_a$ .

### 5.4.4 Drilled-solids fraction

**5.4.4.1** The drilled-solids fraction can be calculated by several methods, from simple solids analysis which correct for salinity and bentonite concentrations to complex material balance methods which correct for additional components such as commercial additives.

**5.4.4.2** The drilled-solids fraction is averaged for the interval, therefore, the averaging method is critical. Sensitivity studies of the effect of the drilled-solids fraction on the final dilution factor show that a significant variance is possible when using different methods of averaging. Comparisons are valid only when using identical averaging methods.

**5.4.4.3** Select the desired method of determining the drilling fluid components, and perform the analyses.

**5.4.4.4** Calculate the drilled-solids fraction and record as  $\varphi_b$ .

#### 5.4.5 Volume of drilling fluid built

The volume of drilling fluid built is determined from the base fluid volume fraction, with the assumption that the drilled-solids concentration and the pit levels remain the same value before and after drilling an interval.

The volume of drilling fluid built,  $V_c$ , is calculated according to Equation (1):

$$V_c = \frac{V_b}{\varphi_a} \quad (1)$$

where

$V_b$  is the volume of base fluid added to total system;

$\varphi_a$  is the base fluid total volume fraction.

#### 5.4.6 Excavated volume of solids drilled

**5.4.6.1** This value can be calculated from the dimensions of the wellbore, i.e. length and diameter. If calliper logs are run, the calculated volume from the logs can be used for the excavated volume.

**5.4.6.2** The excavated volume of drilled solids is the volume of the hole created, multiplied by (1 minus the fractional porosity of the drilled solids).

**5.4.6.3** Calculate the excavated volume of solids drilled and record as  $V_d$ .

#### 5.4.7 Total dilution

The total dilution is the volume of drilling fluid that would be built if there were no solids removal system.

In this case, all drilled solids would be incorporated into the drilling fluid system with dilution being the only form of solids control.

The drilling fluid quality and drilling performance would remain equal whether using dilution exclusively or a drilled-solids removal system.

The total dilution,  $V_e$ , is calculated according to Equation (2):

$$V_e = \frac{V_d}{\varphi_b} \quad (2)$$

where

$V_d$  is the volume of solids drilled;

$\varphi_b$  is the drilled-solids volume fraction.

#### 5.4.8 Dilution factor

The dilution factor is the ratio of the volume of drilling fluid built to the total dilution volume.

It is the ratio of drilling fluid used to actually drill an interval using a solids removal system, as compared to the ratio obtained using only dilution. In both cases, the level of drilled solids in the drilling fluid remains constant and appears in both calculations.

This expression also makes the assumption that the dilution volume reduces the remaining drilled solids in the system to the target concentration. The lower the factor, the more efficient the system.

The dilution factor,  $k$ , is calculated according to Equation (3):

$$k = \frac{V_c}{V_e} \quad (3)$$

where

$V_c$  is the volume of drilling fluid built;

$V_e$  is the volume of total dilution.

#### 5.4.9 Calculation of drilled-solids removal system performance

The drilled-solids removal system performance (efficiency),  $\eta$ , expressed as a percentage, is calculated according to Equation (4):

$$\eta = 100 (1 - k) \quad (4)$$

where  $k$  is the dilution factor.

The example below illustrates the calculation procedure.

**EXAMPLE** Obtain data from drilling fluid and drillers' reports. A typical example is shown in Table 1, and is used for this calculation.

**Table 1 — Drilling fluid report data**

Parameter	SI units	USC units
Base fluid added, $V_b$	2 000 m <sup>3</sup>	13 000 bbl
Average base fluid fraction, $\varphi_a$	0,80	0,80
Initial depth	5 000 m	16 405 ft
Final depth	6 714 m	22 046 ft
Average hole diameter	0,311 2 m	12,25 in
Volume of solids drilled, $V_d$	250 m <sup>3</sup>	8 830 ft <sup>3</sup>
Average drilled-solids fraction, $\varphi_b$	0,05	0,05

Calculate the volume of drilling fluid built,  $V_c$ , using Equation (1), as follows:

$$V_c = \frac{V_b}{\varphi_a} = \frac{2\,000}{0,80} = 2\,500 \text{ m}^3$$

Calculate the total dilution volume,  $V_e$ , using Equation (2), as follows:

$$V_e = \frac{V_d}{\varphi_b} = \frac{250}{0,05} = 5\,000 \text{ m}^3$$

Calculate the dilution factor,  $k$ , using Equation (3), as follows:

$$k = \frac{V_c}{V_e} = \frac{2\,500}{5\,000} = 0,50$$

Calculate the drilled-solids removal system performance,  $\eta$ , using Equation (4), as follows:

$$\eta = 100 (1 - k) = 100 (1 - 0,50) = 50 \%$$

## 6 Rigsite evaluation of drilled-solids management equipment

### 6.1 Principle

**6.1.1** This clause presents a rigsite method for determining the effectiveness of individual pieces of solids control equipment when using a water-based drilling fluid. If mechanical separation equipment is used to remove suspended solids from liquid, one parameter that can be used to measure separator performance is **capture** (see definition 3.1.13).

**6.1.2** Capture analysis is not widely used in the drilling fluids solids control industry for at least two reasons:

- a) the requirement for “representative samples” precludes successful use of capture to evaluate shale shaker performance;
- b) solids concentrations in drilling fluids have traditionally been reported volumetrically rather than gravimetrically.

**6.1.3** Annex A shows the derivation of the capture equation.

### 6.2 Application

**6.2.1** Capture is usually expressed as a percentage of the system-suspended solids, and can be easily calculated if the concentration (mass fraction, expressed as a percentage) of suspended solids is known for the process streams conveyed to and from a separator.

**6.2.2** If samples of the three process streams (feed slurry, overflow slurry and underflow slurry) can be collected and assumed to be representative of steady-state operation of the separator, then calculated capture is a good measure of the effectiveness of the separator.

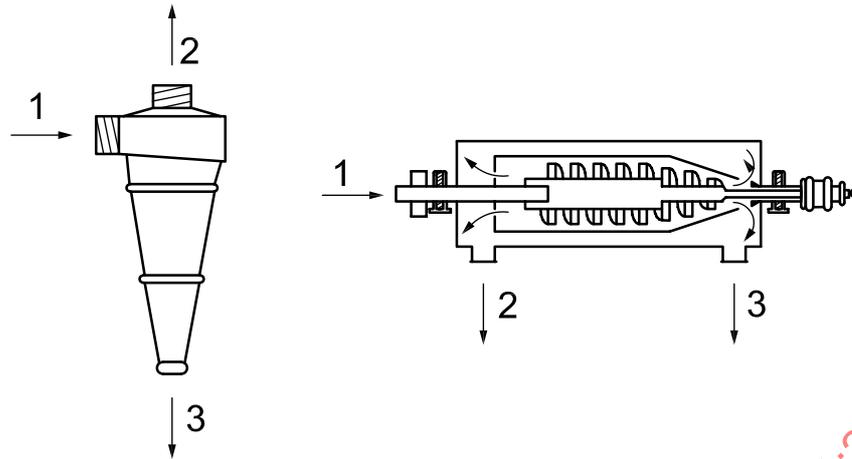
**6.2.3** Capture analysis is a useful tool and should be considered when evaluation of equipment performance on drilling fluid systems is needed. However, the data generated apply only to the time at which the samples are collected.

**6.2.4** Capture data can be extrapolated to predict the solids removed by the separator over longer time periods if the following conditions apply.

- a) The separator is working under steady-state condition with consistent and homogeneous feed;
- b) sufficient data are collected to establish average performance for the time period studied.

**6.2.5** Application of this analysis is limited to evaluation of centrifuges and hydrocyclones. The procedure cannot be applied to shale shakers due to the difficulty in obtaining representative samples of the three process streams and the inherent inconsistency of shale shaker feed conditions.

**6.2.6** The process stream terminology is illustrated in Figure 1 and symbols are defined in 3.2.1.



#### Key

- 1 feed slurry, with mass fraction of solids  $w_1$
- 2 overflow slurry, with mass fraction of solids  $w_2$
- 3 underflow slurry, with mass fraction of solids  $w_3$

Figure 1 — Process stream terminology for centrifugal separators

### 6.3 Sampling of streams for capture analysis

6.3.1 A sample set of each of the three process streams shall be obtained, sealed and labelled for identification.

6.3.2 Each sample volume should be 50 cm<sup>3</sup> to 100 cm<sup>3</sup>.

6.3.3 For each set, the sampling among streams should be done as quickly as possible.

### 6.4 Determination of mass fraction (percent) solids

6.4.1 Carry out an analysis to remove the water and oil phase for each process-stream sample set. For water-based drilling fluids, a moisture determination is required. Oil-based drilling fluids require the use of a retort to vaporize the oil continuous-phase fluid.

6.4.2 Weigh the empty evaporation container and record the mass as  $m_1$ .

6.4.3 Weigh into the container approximately 10 g of each process-stream slurry. Weigh the container plus sample, and record the mass as  $m_2$ .

6.4.4 Dry a water-based sample in a drying oven set to 105 °C (220 °F) for at least 1 h. If testing an oil-based sample, run the retort analysis.

6.4.5 Cool each sample container, and reweigh. Record the mass as  $m_3$ .

6.4.6 Calculate the mass fraction of suspended solids,  $w$ , expressed as a decimal fraction, using Equation (5):

$$w = \frac{(m_3 - m_1)}{(m_2 - m_1)} \quad (5)$$

where

$m_1$  is the mass of empty container, expressed in grams;

$m_2$  is the mass of container plus sample, expressed in grams;

$m_3$  is the mass of dried/retorted container, expressed in grams.

**6.4.7** Correction factors should be determined and applied in cases in which the base liquid contains more than 10 000 mg/l salt, or emulsified oil.

**6.4.8** Unweighted drilling fluids are those not containing barite or other high specific-gravity weighting agent. The procedure outlined in 6.4.1 to 6.4.7 is sufficient to determine the mass fraction of suspended solids in each process stream.

**6.4.9** The quantitative determination of the effects of the solids removal process is then obtained by using the capture calculation described in 6.5 and multiplying the mass fraction of the solids in the discharge stream by the rate at which solids enter the feed stream.

**6.4.10** The mass flow rate of solids in the reject stream can be expressed as dry mass per hour.

## 6.5 Calculation of capture

The mass fraction of suspended solids removed (capture),  $w_a$ , expressed as a percentage, can be calculated using Equation (6):

$$w_a = 100 \frac{w_3 (w_1 - w_2)}{w_1 (w_3 - w_2)} \quad (6)$$

where

$w_1$  is the mass fraction of suspended solids in the feed to a piece of separator equipment, expressed as a decimal fraction;

$w_2$  is the mass fraction of suspended solids in the overflow from a piece of separator equipment, expressed as a decimal fraction;

$w_3$  is the mass fraction of suspended solids in the underflow from a piece of separator equipment, expressed as a decimal fraction.

NOTE If the discharge stream is very small in volume or has a very high solids content, the formula given in Equation (A.1) can give more accurate results.

## 6.6 Interpretation of results

**6.6.1** With centrifuges and hydrocyclones, the reject stream can be either heavy-phase discharge (underflow) or light-phase discharge (overflow).

**6.6.2** If the underflow stream contains the reject solids (heavy-phase discharge), the underflow is discarded. When used in combination with the feed rate, the capture equation permits calculation of the rate at which solids are being removed.

**6.6.3** If the overflow stream contains the reject solids (light-phase discharge), then the percent capture can be calculated by subtracting the capture calculated using Equation (6) from the light-phase discharge.

**6.6.4** If the overflow stream is being discarded, the capture (mass fraction) calculated, together with the feed rate, is used to determine the rate of solids separation.

## 6.7 Procedure for characterizing removed solids

**6.7.1** Segregated solids are characterized by their specific gravity and particle size.

NOTE Specific gravity is the ratio of the mass of a specific volume of material at a specified temperature when compared to an equal volume of reference material at the same (or another) temperature. Most commonly, the reference material is water. For the purposes of this International Standard, the symbol for density,  $\rho$ , will be used for specific gravity.

**6.7.2** Solids in a drilling fluid are a mixture of weighting material (high specific gravity), clay and drilled solids (low specific gravity). The mixture of clay and drilled solids is referred to as low-gravity solids, and the amount is important for drilling fluid maintenance, rate of drilling progress, and potential for interfering events.

**6.7.3** A dried and weighed sample of the separated solids is added to a measured volume of water, and the average specific gravity of the solids determined by the increase in volume and mass. Record this as  $\rho_1$ .

**6.7.4** Determine the percentages of weighting material and low-gravity solids. Low-gravity solids are assumed to have an average specific gravity of 2,6 and the weighting material density  $\rho_2$  is known from the type of weighting agent used. The mass fraction of solids being fed to the separator is taken from 6.5, and noted as  $w_1$ .

## 6.8 Calculation of mass fraction (percent) of low-gravity solids

The mass fraction of the weighting material,  $w_4$ , expressed as a decimal fraction, is calculated according to Equation (7):

$$w_4 = \frac{(\rho_1 - 2,6)}{(\rho_2 - 2,6)} \quad (7)$$

where

$\rho_1$  is the average specific gravity of all separated solids in the sample;

$\rho_2$  is the specific gravity of weighting material used in drilling fluid.

The mass fraction of low-gravity solids,  $w_5$ , expressed as a percentage, is calculated according to Equation (8):

$$w_5 = 100 (w_1 - w_4) \quad (8)$$

where

$w_1$  is the mass fraction of suspended solids in feed, expressed as a decimal fraction;

$w_4$  is the mass fraction of weighting material, expressed as a decimal fraction.

## 6.9 Particle size assessment on removed solids

The primary function of centrifugal processing of weighted drilling fluids is the removal of colloidal particles. Removal of these particles limits the need for dilution.

Given the influence of average particle size on drilling fluid quality, it is recommended that occasional particle size analyses be used to monitor the concentration of colloids and near-colloids to ensure that their concentration does not become excessive.

## 6.10 Economics

### 6.10.1 Unweighted drilling fluids

The economics of discarding the underflow of centrifuges used for solids reduction with unweighted drilling fluids can be evaluated by comparing the cost of the solids removal with the cost of the dilution required by the incorporation, rather than removal, of the separated solids, and the differences in waste disposal costs.

The effect of centrifuging upon the drilling fluid cost can be determined by calculating the volume of dilution that would have been required to compensate for the incorporation of the separated solids, and multiplying by the unit cost of the fluid.

All dilution adds directly to waste volume, thus the cost of disposing of the dilution volume needs to be added to the cost of preparing it.

### 6.10.2 Weighted drilling fluids

Traditionally, centrifuging is used with weighted fluids to reduce dilution requirements by eliminating the very small-sized drilled solids and barite (colloidal particles).

Comparison of the cost of the centrifuging with the value of the barite recovered from the discarded fluid is a frequently used measure of its economic effectiveness. However, the purpose of solids removal equipment is to eliminate undesirable drilled solids.

Centrifuging has a direct effect on waste volume. The dilution volume of the centrifuge feed and the disposal of the liquid in the overflow increase waste volumes significantly.

Less obvious, but of greater importance, is the fact that disposal of the colloids and near-colloids with the liquid provides a better drilling fluid, reduces dilution requirements, and therefore the volume of waste generated.

## 7 Practical operational guidelines

### 7.1 Principle

This clause is intended as a guideline for the design and operation of surface drilling fluid handling systems.

Following these practices maximizes the performance of the surface systems and improves drilling fluid quality. Deviating from these practices diminishes system performance, and increases dilution requirements, by allowing separable solids to recirculate in the drilling fluid system.

### 7.2 Apparatus

**7.2.1 Surface drilling fluid system**, consisting of the flow line, active tanks, reserve tanks, trip tank(s), agitators, pumps, motors, solids and gas removal devices, mixing and shearing devices, and associated piping.

The surface drilling fluid system is composed of the following six sections.

**7.2.1.1 Removal section**, comprising the tanks and equipment used for the separation of drilled solids and gas from the drilling fluid.

**7.2.1.2 Addition section**, comprising the equipment and tanks utilized in the addition and blending of drilling fluid additives.

**7.2.1.3 Suction section**, comprising the tank(s) from which the rig pumps take suction, and any associated pumps or mixing equipment.

**7.2.1.4 Reserve section**, comprising the tank(s) or pit(s) and associated equipment used to isolate drilling fluid from the active system.

**7.2.1.5 Discharge section**, comprising the tank(s) or pit(s) and equipment located at the well site used to store and process drilling fluid and cuttings for disposal.

**7.2.1.6 Trip tank section**, comprising the tank(s) and associated equipment used to isolate drilling fluid from the active systems for gauging pipe displacement during tripping operations.

### 7.3 Procedure for design and operation

#### 7.3.1 General

Drilling fluid exits the wellbore via a flow line and progresses through the solids handling equipment until it is cleaned and taken into the wellbore via the suction tank. The equipment is arranged in a manner to remove successively smaller particles during fluid processing.

#### 7.3.2 Flow line

**7.3.2.1** The flow line is the exit port from the wellbore. The flow line diameter shall be sufficient to handle the maximum anticipated circulation rate at the maximum anticipated drilling fluid viscosity. The flow line shall have a minimum slope of 6° downhill (1:10 ratio of drop per horizontal run).

**7.3.2.2** If the flow line distributes drilling fluid to two shakers, a “Y” connection or other distribution system shall be used to divide the flow equally, minimize solids settling and avoid different rates of solids separation in the manifold.

#### 7.3.3 Tank

**7.3.3.1** Tank(s) receive the flow line discharge and shall be of sufficient capacity to contain the active surface drilling fluid system. The minimum tank(s) volume shall be the sum of the volume and displacement of the drill string at maximum total depth, plus the volume at the bottom of the tanks that cannot be circulated, plus approximately 16 m<sup>3</sup> (100 bbl) safeguard.

**7.3.3.2** When fast-drilling a large diameter hole with high circulation rates, the surface volume as determined in 7.3.3.1 can reduce the surface time available for drilling fluid processing and treatment to below the acceptable minimum. In this case, additional tank volume should be provided and the provision of an active reserve section may be desirable.

#### 7.3.4 Process rate

**7.3.4.1** Equipment process rates are the limiting factor for drilling fluid retention time in the surface system. Solids removal equipment processing capacity requirements are a function of the circulation rate and the rate at which cuttings are generated. Minimum requirements are based on maximum circulation rates assuming that the equipment is properly assembled.

**7.3.4.2** Each piece of equipment shall be capable of processing more fluid than enters its suction compartment. This ensures the ability to process all fluid at each step before it proceeds to the next compartment.

**7.3.4.3** The processing capacity of degassers, desanders, desilters and mud cleaners should be 10 % to 25 % higher than the flow rate of material entering the suction compartment of the equipment. This will also be 10 % to 25 % higher than the maximum anticipated circulation rate only if each piece of equipment is properly assembled.

**7.3.4.4** This does not, however, ensure that the capacity is adequate to permit removal of drilled solids as quickly as they are generated during periods of fast drilling. Nor does it ensure adequate capacity if all fluid is not processed through the removal equipment.

**7.3.4.5** Since maximum penetration rates are difficult to forecast, temporary installation shall be provided for additional equipment that is required during periods in which cuttings are generated more rapidly than can be handled by the permanently installed equipment.

### **7.3.5 Surface tank**

**7.3.5.1** Design guidelines for drilling fluid surface tanks require knowledge of the equipment capability and the anticipated drilling programme. Tank depth shall be approximately equal to the tank width or diameter. Significantly deeper tanks can present problems with achieving adequate mixing. Shallow tanks can lead to formation of vortices and air entrainment.

**7.3.5.2** The minimum surface area of compartments in square metres (square feet) shall be equal to the flow rate, in cubic metres per minute, divided by 1,63 (in gallons per minute, divided by 40). This facilitates the release of entrained gas.

**7.3.5.3** Piping between tanks and tank bottom equalizers should be 25,4 cm (10 in), 30,5 cm (12 in) or 35,6 cm (14 in) in diameter (in accordance with ISO 3183).

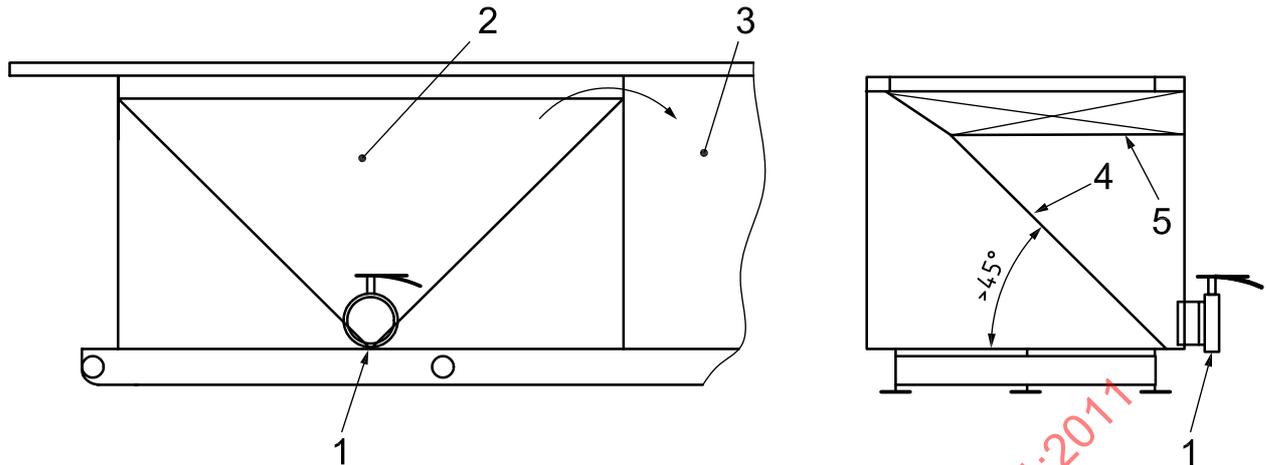
NOTE For the purposes of this provision, API Spec 5L is equivalent to ISO 3183.

These are adequate for circulation rates as high as 3,54 m<sup>3</sup>/min (935 gal/min), 5,11 m<sup>3</sup>/min (1 350 gal/min), and 6,93 m<sup>3</sup>/min (1 830 gal/min), respectively.

**7.3.5.4** Baffles around each mechanical stirrer minimize air vortices and settling. A typical baffle is 2 cm to 3 cm thick by 30 cm wide (1 in thick by 12 in wide) and extends from the tank bottom to 15 cm (6 in) above the top agitator blade. Four baffles are usually installed around each agitator. These four baffles are installed 15 cm (6 in) past the tips of the agitator blades along lines connecting the centre of the agitator blades with the four corners of a square pit or compartment. For a long rectangular pit with two or more agitators, the tank is divided into imaginary square compartments and a baffle is pointed toward each corner.

### **7.3.6 Sand trap**

**7.3.6.1** Sand traps are designed to remove particles greater than 200 µm by settling. The sides of the sand trap shall slope at 45° or more from the horizontal to an area immediately in front of the discharge valve. Figure 2 illustrates the sand trap design.



### Key

- 1 dump gate valve
- 2 sand trap
- 3 degasser chamber
- 4 sand trap floor
- 5 overflow cut out into degasser chamber

Figure 2 — Sand trap design

**7.3.6.2** The discharge valves (dump gate valves) on tanks shall be large, non-plugging, and capable of quick opening and closing. The valve shall be operable from the level of the tanks, and flow from the valve shall be visible from the position from which the valve is operated.

**7.3.6.3** Fluid shall enter the sand trap at its upstream end, and flow from it over a high, tank-width weir at its downstream end. The recommended weir height is 15 cm (6 in) below the top of the tank.

**7.3.6.4** The sand trap shall receive the screen underflow from the shakers, and should be designed to allow for bypassing when necessary.

**7.3.6.5** Most of the settled solids can be dumped with minimal loss of drilling fluid. The valve is opened, the discharge observed, and the valve closed when drilling fluid begins to flow from the sand trap.

### 7.3.7 Removal section

**7.3.7.1** The removal section of drilling fluid handling equipment normally consists of five compartments, usually the sand trap, the degasser compartment, and the compartments from which the desander, desilter, and centrifuge(s) each process fluid. If a centrifuge is not used, only four compartments are required.

**7.3.7.2** The solids removal equipment shall be installed in a manner that permits the removal of progressively finer solid particles as the fluid moves through the system.

### 7.3.8 Flow direction

**7.3.8.1** Proper flow direction between compartments is imperative for proper operation. Drilling fluid shall overflow from the sand trap into the degasser suction compartment, which is the next compartment downstream.

**7.3.8.2** Tank bottom equalization shall be provided between all removal section compartments downstream of the degasser suction compartment.

**7.3.8.3** An adjustable riser shall be installed on the downstream side of the equalizer between the removal and addition sections, to permit control of the fluid level in the removal section.

### **7.3.9 Tank agitation**

**7.3.9.1** Drilling fluid tank agitation is necessary to prevent solids accumulation in the tank. With the sole exception of the sand trap, all compartments shall be mechanically agitated.

**7.3.9.2** If mud guns are chosen instead of mechanical agitators for some compartments, the mud guns should take suction from the same compartment into which they discharge. A centrifugal pump may stir this suction tank and shall never pump fluid from one compartment to another.

**7.3.9.3** The manufacturer's guidelines shall be consulted for specific information on mechanical agitator blade size and geometry, and for power requirements.

### **7.3.10 Fluid routing**

**7.3.10.1** Fluid is routed through process equipment downstream into the next compartment. The centrifugal pump used to power the jet on vacuum degassers shall take suction from the same compartment into which the vacuum degasser discharges.

**7.3.10.2** The fluid shall be degassed before it reaches the pumps feeding downstream equipment.

**7.3.10.3** Suction and discharge line diameter requirements depend upon the volumes of fluid to be circulated. Lines shall be sized in accordance with the manufacturer's recommendations. See 7.8 and 7.9 for specifics.

**7.3.10.4** Desanders shall draw suction from the compartment immediately downstream from the degasser compartment. Desilters and mud cleaners shall draw from the next compartment, and centrifuges from the next compartment.

**7.3.10.5** Different types of equipment shall never take suction from the same compartment.

**7.3.10.6** Like types of equipment shall always take suction from the same compartment.

**7.3.10.7** The desilter portion of a combination mud cleaner shall be plumbed following the desilter guidelines, and the desander portion following those for desanders.

**7.3.10.8** All solids removal equipment shall discharge processed fluid to the next downstream compartment.

**7.3.10.9** Drilling fluid from other compartments shall never be pumped into a removal compartment from points downstream through mud guns, mixers, or the eductor of a vacuum degasser.

## **7.4 Design of shale shakers**

**7.4.1** Shale shaker skirts shall be level.

**7.4.2** Shakers shall be rigged with adequate space, walkways and handrails to permit easy and safe servicing.

**7.4.3** If the shaker is equipped with a rear tank (possum belly), the flow line shall enter the rear tank as near to the bottom as possible.

**7.4.4** If the flow line enters the rear tank via an "elbow" over its top, the elbow shall extend to within one flow line diameter of the bottom of the tank.

**7.4.5** A means of diverting fluid from the flow line is recommended to permit the disposal of cement, spotting fluids, contaminated fluids, etc., before these fluids reach the shale shaker. This procedure shall not be used to dump the rear tank into the sand trap before trips.

## **7.5 Operation of shale shakers**

**7.5.1** Inspect the screens every time circulation is interrupted.

**7.5.2** Never bypass the shale shaker(s) while circulating or on trips into the hole. This includes dumping the rear tank into the active system.

**7.5.3** Screen all fluids, including that shipped to the rig from elsewhere, before they enter the active system tanks.

**7.5.4** Spray bars should be used only when required for the handling of gumbo or sticky clays. The orifices or jets on the bar shall be small enough to deliver water in a mist, rather than in a spray.

**7.5.5** Use the shaker screens with the smallest openings that do not cause excessive drilling fluid loss.

**7.5.6** Under normal operating conditions and when using a single-deck shaker with multiple screens, all screens shall have the same API designation (as defined in Clause 11).

**7.5.7** On double-deck shakers with flow in series through the two decks, the top screen shall always be coarser than the screen in the lower position. A difference of two API designation sizes is generally effective.

**7.5.8** Replace or repair promptly all torn or damaged screens.

**7.5.9** Do not routinely operate adjustable deck shakers in the maximum upwards position. This practice will cause degradation of cuttings, and on some shakers permit fluid to spill over the back of the screen bed.

**7.5.10** Screen selection with weighted drilling fluids involves a compromise to accommodate the need to maximize cuttings removal while not separating excessive quantities of weighting material. Usually an API 200 size screen is the finest shaker screen that does not remove excessive quantities of weighting material (i.e. barite).

**NOTE** Some weighting material loss is inevitable when screening weighted drilling fluids. Drilled solids retain drilling fluid as they leave the shaker screens.

**7.5.11** Observe the manufacturer's recommendations on screen installation and tensioning as well as on routine general maintenance.

**7.5.12** When using shaker screens that need tensioning, check tension 15 min to 30 min after installation and hourly thereafter.

## **7.6 Design of degassers**

**7.6.1** The degasser shall draw suction from the compartment immediately downstream from the sand trap.

**7.6.2** When the sand trap is in use, flow to the degasser compartment shall be over a long, high weir.

**7.6.3** While the degasser is in use, there shall be no tank bottom equalization between the degasser compartment and those adjacent to it.

**7.6.4** Degas fluid before it reaches the pumps feeding the downstream equipment.

**7.6.5** The pump used to power the jet on vacuum degassers shall take suction from the same compartment into which the vacuum degasser discharges.

**7.6.6** Position the degasser suction 30 cm (12 in) above the tank bottom.

7.6.7 Agitate the degasser compartment well.

7.6.8 The centrifugal pump feeding the eductor jet of vacuum degassers shall provide the feed head recommended by the manufacturer. Install a pressure gauge to permit the head to be verified.

7.6.9 The degasser capacity shall be at least equal to the planned circulation rate in all of the hole intervals in which gas intrusion is considered to be a hazard.

## 7.7 Operation of degassers

7.7.1 Operate degassers to receive all drilling fluid from the lowest portion of the borehole ("bottoms") after trips. Crews should be familiar with start-up procedures and provide regular checks to confirm that the equipment is working properly.

7.7.2 Calculate the volume fraction (percent) gas or air in a drilling fluid by dividing the difference between pressurized drilling fluid density and unpressurized drilling fluid density by the pressurized drilling fluid density, and multiplying this fraction by 100. The calculation can be expanded to include the possibility of dissolved gas by subtracting from 100 % the mass of unpressurized drilling fluid divided by the mass of the same volume of degassed drilling fluid, expressed as a percentage.

## 7.8 Design of desanders and desilters

7.8.1 Desanders shall draw suction from the compartment immediately downstream from the degasser compartment. Desilters and mud cleaners shall draw from the compartment immediately downstream from the desander, centrifuges shall draw from the compartment immediately downstream from the desilters and mud cleaners from the compartment after that.

- a) For example, if the sand trap is designated compartment #1 and the following downstream compartments are numbered sequentially, the degasser shall draw suction fluid from compartment #2 and discharge fluid to compartment #3.
- b) The desanders then process the fluid from compartment #3 and discharge it to compartment #4.
- c) The desilter or mud cleaner(s) then process the fluid from compartment #4 and discharge it to compartment #5.
- d) If a centrifuge or centrifuges are used on the active system, the centrifuges process fluid from compartment #5 and discharge it to compartment #6.

7.8.2 Each hydrocyclone (desander or desilter) feed manifold shall have its own pump and motor (dedicated pumps).

7.8.3 "Roping" hydrocyclone discharge indicates solids overload, as well as the need to

- add additional equipment, or
- reduce penetration rate, or
- accept the contamination of the drilling fluid with recirculated drilled solids.

7.8.4 The piping between the pump and the input manifold for this equipment shall be as short and straight as possible. There should be no elbows, reducers or swages within three pipe diameters of the flange connecting the piping to the manifold.

7.8.5 Suction piping shall be designed for linear flow velocity of 1,22 m/s (4 ft/s) to 2,44 m/s (8 ft/s); 15,2 cm (6 in) with nominal pipe [outer diameter 16,8 cm (6,675 in)] for planned flow rates from 1,33 m<sup>3</sup>/min (350 gal/min) to 2,65 m<sup>3</sup>/min (700 gal/min), and 20,3 cm (8 in) nominal pipe [outer diameter 21,9 cm (8,675 in)] to 4,54 m<sup>3</sup>/min (1 200 gal/min). See pump tables (not included) for volumetric rates beyond these ranges.

**7.8.6** Discharge lines shall be 15,2 cm (6 in) nominal pipe [outer diameter 16,8 cm (6,675 in)] for volumetric rates from 1,33 m<sup>3</sup>/min (350 gal/min) to 3,41 m<sup>3</sup>/min (900 gal/min), and 20,3 cm (8 in) nominal pipe [outer diameter 21,9 cm (8,675 in)] to 5,68 m<sup>3</sup>/min (1 500 gal/min).

**7.8.7** Install pressure gauges on the input manifolds to permit the head at the manifold to be monitored.

Many oilfield hydrocyclones are designed to operate at 23 m (75 ft) of head. Verify this by using Equation (9) to calculate the head corresponding to the measured pressure.

For SI units, the head,  $h$ , expressed in metres, is calculated according to Equation (9):

$$h = \frac{p}{9,8 \rho} \quad (9)$$

where

$p$  is the pressure, in kilopascals;

$\rho$  is the drilling fluid density, in kilograms per cubic metre.

In SI units, a head of 25 m requires a pressure 245 times the drilling fluid density, in kilograms per cubic metre.

For USC units, the head,  $h$ , expressed in feet, is calculated according to Equation (10):

$$h = \frac{19,2p}{\rho}$$

where

$p$  is the pressure, in pounds force per square inch;

$\rho$  is the drilling fluid density, in pounds per gallon.

In USC units, a 75 ft head requires a pressure 3,9 times the drilling fluid density, in pounds per gallon.

**7.8.8** Proper installation requires that the hydrocyclone unit be installed at an elevation that will prevent siphoning of fluid from the drilling fluid tank when the unit is not in operation. The manifolds shall be higher than the maximum fluid level in the compartments to which they are connected.

**7.8.9** If the vertical distance between the discharge manifold and the end of the pipe carrying the discharged fluid to the next compartment is more than 1,8 m (6 ft), a vent shall be provided in the discharge manifold near the hydrocyclones to prevent siphoning.

**7.8.10** The discharge line to the tank receiving the discharged fluid shall end above the maximum fluid level in the tank.

**7.8.11** For proper operation of this equipment, provide sufficient space, walkways, ladders and hand rails to permit easy and safe service.

## 7.9 Design of mud cleaners

**7.9.1** As noted in previous clauses, installation of mud cleaner hydrocyclones follows the rules for desanders and desilters, as appropriate. Mud cleaners remove additional drilled solids even after the fluid has been processed by API 200 screens on the main shale shakers.

**7.9.2** Mud cleaners shall be used when commercial weighting agents are added to the drilling fluid.

**7.9.3** Plugged desilter cones indicate that drilling fluid is bypassing shale shaker screens and a mud cleaner should be installed.

**7.9.4** Screened throughput from mud cleaners shall be returned to a well-agitated location in the drilling fluid tanks. Screened throughput from mud cleaners has very little carrying capacity, and will not transport solids well.

## **7.10 Design of centrifuges**

**7.10.1** Normally, the underflow (cake, heavy slurry) is discharged while centrifuging unweighted fluids. The overflow (centrate, effluent light slurry), containing most of the viscosity-building colloidal particles, is discharged from weighted fluids. Accordingly, install centrifuges in a manner that permits either stream to be discharged, or either to be returned to the active drilling fluid system.

**7.10.2** Take the centrifuge feed from a well-agitated area of the compartment immediately upstream from the discharge compartment.

**7.10.3** If the centrifuge underflow (heavy slurry) is returned to the drilling fluid system, discharge it to a well-agitated area of the receiving compartment.

**7.10.4** The receiving compartment shall be on the upstream side of the adjustable riser.

**7.10.5** When processing unweighted drilling fluids, use the centrifuge(s) for drilled-solids removal, processing as much fluid as possible and discarding the underflow (cake, heavy slurry).

**7.10.6** With weighted drilling fluids, use centrifuges to control low-shear rate viscosity and drilling fluid quality by removing colloidal and near-colloidal particles in the overflow. Operate the centrifuges as long and as often as necessary to control low-shear rate viscosity, as well as plastic viscosity.

**7.10.7** While processing weighted fluids, dilute the feed fluid as needed to control the overflow viscosity to no more than 35 s/l (37 s/qt) for water-based fluids and under 38 s/l (40 s/qt) for oil-based fluids as measured by the Marsh funnel.

NOTE Seconds per litre (seconds per quart) are the units traditionally used to describe viscosity as measured by a Marsh funnel.

## **7.11 Use of addition sections**

**7.11.1** Any fluid introduced into the drilling fluid tank system shall pass through the shale shaker screens, including drilling fluid from other sources and drilling fluid dumped from trip tanks.

**7.11.2** All commercial material additions shall enter the system in the addition section, which may be one or several compartment(s).

**7.11.3** In order to facilitate complete blending before circulation, material additions shall take place as far as possible from the compartment(s) from which the fluid is pumped downhole.

**7.11.4** A premix tank is recommended. Bentonite shall be prehydrated before it is added to the active system.

## **7.12 Use of drilling fluid mixing and blending equipment**

**7.12.1** Drilling fluid mixing hoppers shall include a jet nozzle and a Venturi tube for proper mixing.

**7.12.2** In order to avoid aeration of the circulated fluid, do not extend hopper discharge lines below the maximum fluid level in the tank.

**7.12.3** In order to avoid aeration of the circulated fluid, turn off the hopper when not in use.

**7.12.4** Shearing devices are recommended for accelerating the hydration of polymers and bentonite. Do not circulate solids-laden fluids through shearing devices. The shear accelerates solids size degradation, thereby diminishing fluid quality.

### 7.13 Use of suction section

**7.13.1** The suction section shall be the section of largest volume in the surface system.

**7.13.2** The suction section shall be well agitated to provide uniform drilling fluid properties.

**7.13.3** The suction section shall include a small slugging tank with submerged mud guns for stirring and suspension. The suction for the pump feeding these guns shall come from the slug tank.

### 7.14 Use of discharge section

**7.14.1** The space, equipment and personnel available in the discharge section shall be adequate for handling the amount of waste to be generated.

**7.14.2** The volume of drilled solids is expected to be at least three times the gauge-hole volume. With poor solids removal performance the volume of discarded fluid can be significantly larger.

**7.14.3** The volume of excess drilling fluid generated while drilling is highly variable and can vary from three or four to ten or fifteen times the drilled volume.

**7.14.4** The solids removal efficiency of the equipment determines the volume of drilling fluid waste.

**7.14.5** The higher volumes are expected when drilling softer formations with water-based drilling fluid.

## 8 Conductance of shale shaker screens

### 8.1 Principle

Shaker screens are no longer simple weaves that are easily described. This clause describes methods of identifying shale shaker screens by a conductance, an equivalent aperture opening size, and a non-blanked area.

### 8.2 Principle of conductance

#### 8.2.1 General

Screen conductance is a measure of the ability of a Newtonian fluid to pass through the screen. Conductance has the unit of permeability per unit length (e.g. kilodarcies per millimetre). Screen conductance is used to compare various screens that have different appearances and different API numbers.

A shaker-screen conductance is measured by determining the flow rate of a fluid through a measured screen area for a measured pressure drop across the screen.

#### 8.2.2 Darcy's law

Darcy's law provides a method of calculating the permeability of a porous medium. A shale shaker screen could be considered a porous medium. The permeability divided by the height of flow path through the porous medium is called the conductance.

Darcy's law states that the flow rate through a porous medium,  $q$ , is directly proportional to the differential pressure,  $\Delta p$ , and the cross-sectional area of the porous medium,  $A$ , and is inversely proportional to the fluid viscosity,  $\mu$ , and the length of the porous medium,  $L$ .

The constant of proportionality,  $K$ , is called the permeability. If the flow rate is measured in cubic centimetres per second, the cross-sectional area in square centimetres, the fluid viscosity in centipoises, the pressure differential in atmospheres and the length in centimetres, then the permeability will be expressed in darcies (see definition 3.1.22, Note).

Darcy's law can be stated as in Equation (10):

$$q = \frac{K(\Delta p \times A)}{\mu \times L} \tag{10}$$

where

- $q$  is the flow rate through a porous medium, expressed in cubic centimetres per second;
- $K$  is the constant of proportionality, or permeability, expressed in darcies;
- $\Delta p$  is the differential pressure, expressed in atmospheres<sup>5)</sup>;
- $A$  is the cross-sectional area, in square centimetres;
- $\mu$  is the fluid viscosity, expressed in centipoises;
- $L$  is the length of the porous medium, expressed in centimetres.

Solve Darcy's law for the permeability per unit length, or conductance,  $C$ , using Equation (11):

$$C = 10^{-4} \times \frac{K}{L} = 10^{-4} \times \frac{\mu \times q}{\Delta p \times A} \tag{11}$$

where

- $C$  is the conductance, expressed in kilodarcies per millimetre;
- $K$  is the constant of proportionality, or permeability, expressed in darcies;
- $L$  is the length of the porous medium, expressed in centimetres;
- $\mu$  is the fluid viscosity, expressed in centipoises;
- $q$  is the flow rate through a porous medium, expressed in cubic centimetres per second;
- $\Delta p$  is the differential pressure, expressed in atmospheres;
- $A$  is the cross-sectional area, in square centimetres.

The flow rate through the screen needs to be laminar to provide a reproducible number. Therefore, the velocity should be maintained below a range of 2 cm/s to 3 cm/s (approximately 1 in/s).

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5) 1 Pa = 9,869 2 × 10<sup>-6</sup> atm. The atmosphere (atm) is neither an SI nor a USC unit of pressure. At the tenth General Conference on Weights and Measures (Conférence Générale des Poids et Mesures, CGPM) in 1954, standard atmosphere was defined as being precisely equal to 101 325 Pa (14,696 lb/in<sup>2</sup>). This value was intended to represent the mean atmospheric pressure at mean sea level at the latitude of Paris, France (in practical terms, this value also corresponds to the mean sea level pressure for many industrialized nations whose latitudes are similar to that of Paris).

Conductance of a shale shaker screen is determined by measuring the flow rate of a Newtonian fluid with a known viscosity, flowing through a shaker screen, with a measured area perpendicular to the flow, and a known pressure drop. Conductance is expressed in metres (SI units) or darcies per inch (USC units). For the purposes of this International Standard, the conductance,  $C$ , is expressed in kilodarcies per millimetre (kD/mm).

For a particular fluid (of known viscosity) and the same pressure differential across the screen, the conductance is proportional to the velocity of fluid through the screen,  $q/A$ .

### 8.3 Apparatus for measurement of conductance

**8.3.1 Fluid reservoir**, to provide the necessary volume of fluid needed for the tests. The suggested size of the fluid reservoir is about 0,2 m<sup>3</sup> (50 gal).

**8.3.2 Discharge flow line from the reservoir**, having a valve to adjust the flow rate from the reservoir and deflection plate at the end of the discharge piping to prevent the reservoir fluid from directly impacting the screen.

#### 8.3.3 Screens:

- a) Screens shall be mounted as they are used on shale shakers. Continuous cloth shaker screens shall be mounted so that they are in tension. Panel screens may be mounted as they are.
- b) Screen cloth shall be mounted on either a shaker or a tensioning device before a sample is prepared. After tension is applied, the screen is glued between two short pieces of 15,2 cm (6 in) Schedule 80 polyvinyl chloride (PVC) pipe with epoxy. Each section of pipe should be 16,5 cm (6,5 in) outside diameter, 14,6 cm (5,75 in) inside diameter, and either 3 cm (1 in), 5 cm (2 in) or 8 cm (3 in) long. Care shall be taken to ensure that the intersection between the PVC pipe and the screen is completely sealed so that fluid cannot escape from the sides of the ring.
- c) The screens shall be placed between the PVC pipe in such a way as to minimize the blanked area from the screen mounting plate. When successfully mounted, the screen will appear to have mirror images of itself both perpendicularly and horizontally.
- d) Failure to properly tension the screen before mounting results in erroneous information in the conductance test and in determining the API number as described in Clause 9. Screens mounted as described in c) above may also be used to measure the API number for the screen.

**8.3.4 Screen set-up for conductance test**, mounted between the two sections of PVC pipe, and placed below the reservoir discharge pipe. The top of the PVC pipe is levelled with a bubble level. The fluid flowing through the screen is captured in a container mounted on an electronic balance (see 8.3.5). A seal is required to separate the excess fluid from the fluid flowing through the screen. The excess fluid that overflows the screen is captured in a separate container (see 8.3.6). Sufficient overflow drainage shall be supplied so that the test fluid can easily overflow the top of the PVC section of the screen mounting.

**8.3.5 Capture reservoir**, to receive the fluid flowing through the screen, mounted on an electronic balance with an accuracy of 10 g (0,01 kg). A data collection system with automatic electronic measurement of the change in mass as a function of time is recommended. The mass measurements are used to determine the flow rate through the screens.

**8.3.6 Excess fluid reservoir**, to receive the excess fluid that overflows the test screen.

**8.3.7 Pump** (optional), to transfer the fluid from the capture reservoir and the excess fluid reservoir to the fluid reservoir for additional tests.

**8.3.8 Temperature device**, with an accuracy of 0,05 °C (0,1 °F).

#### 8.4 Procedure for calibrating fluid

Using a viscometer<sup>6)</sup> capable of measuring viscosity to an accuracy of 0,000 2 Pa·s (0,2 cP), determine the viscosity of the test fluid over the range of temperatures of the conductance testing.

Determine the density of the test fluid as a function of temperature over the range of temperatures of the conductance test.

#### 8.5 Procedure for flow test

**8.5.1** Measure the flow rate through the screen. Mount the screen in an apparatus that will allow flow onto the screen and maintain a constant height of liquid above the screen surface. Accurately measure the height of the fluid from the screen to the free surface of the liquid and use it to determine the pressure difference across the screen to calculate conductance.

**8.5.2** Use a viscous liquid in order to maintain a low flow rate through the screen and keep a constant liquid level above the screen. Flowing oil onto the screen provides an appropriate liquid.

NOTE A motor oil (e.g. 10/40 weight motor oil) is preferred to a mineral oil because it provides an oil wetting of the screens as the flow is adjusted. A water-wet screen has a much lower conductance or permeability to oil than an oil-wet screen.

**8.5.3** Adjust the flow rate onto the screen so that a small amount overflows the top of the PVC pipe. This will keep the applied head constant.

**8.5.4** Collect the excess flow onto the screen in a trough surrounding the screen sample, and let it flow into a storage container (see 8.3.6). Measure the flow rates through the screen by providing a capture reservoir (see 8.3.5) beneath the screen that is on an electronic balance.

**8.5.5** When the flow rate reaches a steady state, measure the increase in mass of the capture reservoir as a function of time. For screens with a low API number, some of the area of flow may be blocked to decrease the quantity of oil required to reach an equilibrium flow rate.

**8.5.6** Prepare calibration charts for determining the viscosity and density of the oil measured as a function of temperature.

NOTE Oil changes viscosity and density with a change in temperature.

**8.5.7** The temperature of the flow test should remain constant. By measuring the temperature of the fluid that flows through the screen, determine the values for density and viscosity of the oil from the calibration charts.

#### 8.6 Procedure for measuring pressure drop

**8.6.1** The pressure causing the viscous liquid to flow through the screen is provided by the head or height of the free liquid surface.

**8.6.2** Mount the screen between the PVC pipes so that the top of the PVC pipe is horizontal.

**8.6.3** Divert the flow from the fluid reservoir at the end of the input piping so that a minimum disturbance is obvious on top of the fluid above the screen sample.

**8.6.4** Adjust the flow from the fluid reservoir so that a small amount overflows the top of the PVC pipe above the screen. Measure this height, which should be in the range of 0,3 cm (0,125 in).

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6) Ubbelohde Tube Viscometer is an example of a suitable product available commercially. This information is given for the convenience of users of this International Standard and does not constitute an endorsement by ISO of this product.

**8.6.5** Measure the height of the fluid from one-half the distance through the screen. In the case of screens that are not flat, measure the liquid level from one-half of the height of the vertical protrusion. In this case, at least 3,0 cm (1 in) of oil shall cover the top of the screen vertical protrusion. This may necessitate using a longer section of PVC pipe.

## 8.7 Procedure for conductance test

**8.7.1** Place the test screen in the flow apparatus and verify the seal between overflow and fluid through the screen.

**8.7.2** Level the top of PVC pipe with a bubble level.

**8.7.3** Open the fluid reservoir bottom flow valve and adjust the flow rate so that about 0,3 cm (0,125 in) of oil film is overflowing the PVC pipe.

**8.7.4** Monitor the mass of fluid flowing through the screen until the flow rate is constant.

**8.7.5** Measure the mass of fluid flowing through the screen for a specific period of time.

NOTE Data capture with electronics and computer increases the accuracy of the measurements.

**8.7.6** Measure the temperature of the fluid received in the capture reservoir.

**8.7.7** After the test, transfer the oil back to the top reservoir for the next test.

## 8.8 Calculation of conductance

**8.8.1** Determine the average temperature of oil in the capture reservoir during the flow test.

**8.8.2** Calculate, from calibration charts, the viscosity and density of the oil during the test.

**8.8.3** Determine the pressure differential across the screen from the density of the oil during the test. Darcy's law requires this pressure differential to be expressed in atmospheres of pressure.

a) If the head for testing,  $h_T$ , and the density of oil,  $\rho$ , are measured in SI units, the pressure differential,  $\Delta p$ , expressed in atmospheres, is calculated according to Equation (12):

$$\Delta p = 0,096\ 78 \times 10^{-6} \times h_T \times \rho \quad (12)$$

where

$h_T$  is the head for testing, measured in millimetres;

$\rho$  is the oil density, measured in kilograms per cubic metre.

b) If the head for testing,  $h_T$ , and the density of the oil,  $\rho$ , are measured in USC units, the pressure differential,  $\Delta p$ , expressed in atmospheres, is calculated according to Equation (13):

$$\Delta p = 0,294\ 6 \times 10^{-3} \times h_T \times \rho \quad (13)$$

where

$h_T$  is the head for testing, expressed in inches;

$\rho$  is the oil density, measured in pounds per gallon.

**8.8.4** Determine the average viscosity of the oil during the test from the calibration chart and the temperature.

**8.8.5** Determine the flow rate during the test by dividing the mass of the fluid captured during the test by the average density of the oil during the test and the duration of the test.

**8.8.6** Measure the inside diameter of the PVC pipe and determine the area in square centimetres.

**8.8.7** Calculate the conductance.

a) If the SI units are used, the conductance,  $C$ , of the test screen, expressed in kilodarcies per millimetre (kD/mm), is calculated according to Equation (14):

$$C = 0,00167 \times \frac{\mu \times q}{\Delta p \times A} \quad (14)$$

where

$\mu$  is the fluid viscosity, in pascal seconds;

$q$  is the flow rate through a porous medium, in millilitres per minute;

NOTE 1 ml = 1 cm<sup>3</sup>.

$\Delta p$  is the differential pressure, in atmospheres;

$A$  is the cross-sectional area of the porous medium, in square centimetres.

b) If the USC units are used, the conductance,  $C$ , of the test screen, expressed in kilodarcies per millimetre (kD/mm), is calculated according to Equation (15):

$$C = 0,000\ 977\ 9 \times \frac{\mu \times q}{\Delta p \times A} \quad (15)$$

where

$\mu$  is the fluid viscosity, in centipoises;

$q$  is the flow rate through a porous medium, in gallons per minute;

$\Delta p$  is the differential pressure, in atmospheres;

$A$  is the cross-sectional area of the porous medium, in square inches.

EXAMPLE 1 The following is an example of the calculation using SI units, according to Equation (14).

— Test parameters:

— oil viscosity,  $\mu$ : 0,1 Pa·s

— oil density,  $\rho$ : 900 kg/m<sup>3</sup>

— head,  $h_T$ : 54 mm

— Screen: mounted in a PVC pipe of diameter 14,6 cm.

— Flow: stabilized after a 5 min period.

— Test results: 13,5 kg of oil flowed through the sample screen.

Calculate test pressure differential with oil density, in grams per millilitre:

$$\Delta p = 0,096\,78 \times 10^{-6} \times h \times \rho = 0,096\,78 \times 10^{-6} \times 54 \times 900 = 0,470 \times 10^{-2} \text{ atm}$$

$$A = \pi R^2 = \pi(7,3)^2 = 167,42 \text{ cm}^2$$

$$q = \frac{13\,500 \text{ g}}{0,90 \times 5 \text{ min}} = 3\,000 \text{ ml/min}$$

$$C = 0,00167 \times \frac{\mu \times q}{\Delta p \times A} = 0,00167 \times \frac{(0,1 \times 3\,000)}{(0,004\,70 \times 167,42)} = 0,637 \text{ kD/mm} = 0,64 \text{ kD/mm}$$

EXAMPLE 2 The following is an example of the calculation using USC units, according to Equation (15).

— Test parameters:

- oil viscosity,  $\mu$ : 100 cP
- oil density,  $\rho$ : 7,50 lb/gal
- head,  $h$ : 2,125 in

— Screen: mounted in a PVC pipe of diameter 5,75 in.

— Flow: stabilized after a 5 min period.

— Test results: 29,7 lb of oil flowed through the sample screen.

Calculate oil density, in pounds per gallon:

$$\Delta p = 0,294\,8 \times 10^{-3} \times h \times \rho = 0,294\,8 \times 10^{-3} \times 2,125 \times 7,50 = 0,004\,70 \text{ atm}$$

$$A = \pi R^2 = \pi(2,875)^2 = 25,97 \text{ in}^2$$

$$q = \frac{29,7}{7,5 \times 5} = 0,792 \text{ gal/min}$$

$$C = 0,000\,977\,9 \times \frac{\mu \times q}{\Delta p \times A} = 0,000\,977\,9 \times \frac{(100 \times 0,792)}{(0,004\,70 \times 25,97)} = 0,635 \text{ kD/mm} = 0,64 \text{ kD/mm}$$

## 9 Shale shaker screen designation

### 9.1 Principle

This clause provides a method for determining the API US sieve number equivalent of a shaker screen using a laboratory sieve shaker, US standard test sieves, and sized aluminium oxide (aluminium oxide) (CAS No. 1344-28-1) test media samples. Screens are rated on the US sieve number scale by the separations that are achieved in dry-sieving standard aluminium oxide samples, and then comparing these separations to the separations of the same standard aluminium oxide samples with standard US sieves.

A shaker screen which separates the aluminium oxide sample similar to a US 100 test sieve is designated an API 100.

The procedure uses aluminium oxide (Al<sub>2</sub>O<sub>3</sub>) (alumina) which has a specific gravity of 3,5 to 3,9. It is designated as AIO.

All particles larger than the **D100 separation** (see definition 3.1.24) are retained by the test screen.

**9.2 Apparatus**

**9.2.1 Testing sieve shaker**, providing simultaneous rotating and tapping action, that accepts a sieve as described in 9.2.2. The shaker shall be calibrated to the following: 290 r/min, 156 taps/min, tapper height 3,3 cm (1,3 in) with a timer accuracy of ±5,0 s.

NOTE Ro-Tap® sieve shaker<sup>7)</sup> is an example of a testing sieve shaker.

**9.2.2 Standard 20 cm (8 in) diameter test sieves (calibrated)**. The sieves may be full or half height. A sieve cover and a sieve pan are also required. These sieves shall conform to ISO 3310-1.

NOTE For the purposes of this provision, ASTM E11-95 is equivalent to ISO 3310-1.

The standard US test sieves recommended in this clause have the properties shown in Table 2.

**Table 2 — US test sieve designations**

Standard opening µm	Alternative designation	Permissible variation µm	Maximum opening for 5 % µm	Maximum individual opening µm
300	50	±14	337	363
250	60	±12	283	306
212	70	±10	242	263
180	80	±9	207	227
150	100	±8	174	163
125	120	±7	147	192
106	140	±6	126	141
90	170	±5	108	122
75	200	±5	91	103
63	230	±4	66	89
53	270	±4	57	76
45	325	±3	48	66

**9.2.3 ASTM recommended openings**, as shown in Table 3.

NOTE These are listed as alternative sieve designations in Table I of ASTM E11-95.

7) Ro-Tap is an example of a suitable product available commercially. It is the trade name of a product supplied by W.S. Tyler Company, Mentor, OH USA. This information is given for the convenience of users of this International Standard and does not constitute an endorsement by ISO of this product.

Table 3 — ASTM sieve designation

US sieve number	Opening $\mu\text{m}$	US sieve number	Opening $\mu\text{m}$
5	4 000	50	300
6	3 350	60	250
7	2 800	70	212
8	2 360	80	180
10	2 000	100	150
12	1 700	120	125
14	1 400	140	106
16	1 180	170	90
18	1 000	200	75
20	850	230	63
25	710	270	53
30	600	325	45
35	500	400	38
40	425	450	32
45	355	500	25

**9.2.4 Test screen holder**, constructed of light-weight aluminium or, preferably, use the screen holder described in 8.3.3 and 8.3.4.

**9.2.5 Digital balance**, of capacity up to 3 000 g and accuracy of 0,01 g. The balance shall be capable of weighing the total combined mass of the test screen and the retained aluminium oxide test media, the latter being a maximum of 80 g.

**9.2.6 Sieve brush**: a hair brush shall be used on sieves US No. 100 and finer to reduce the possibility of damage to the fine sieve cloth. Nylon or equivalent may cause damage to the sieve cloth.

NOTE From Table 3, a US No. 100 sieve has an opening of 150  $\mu\text{m}$ .

**9.2.7 Marked or labelled jars or other containers**, suitable for storing various US sieve fractions of sized AIO.

**9.2.8 Bowl or pan**: a large, shallow bowl with a 30 cm (12 in) outer diameter at the top or a rectangular pan with a minimum 25,4 cm (10 in) to 30,5 cm (12 in) short side and a depth of 5 cm (2 in).

**9.2.9 Container with sealing lid**, large enough to hold 50 g aluminium oxide and water.

**9.2.10 Distilled or deionized water**.

**9.2.11 Oven**, regulated to between 105 °C (220 °F) and 120 °C (250 °F).

### 9.3 Preparation of aluminium oxide test media

#### 9.3.1 Preparation of aluminium oxide cuts

**9.3.1.1** Accurately-sized aluminium oxide samples are available from several suppliers. These range in size from very coarse to very fine. Use fractions of one or more of these sized aluminium oxide samples as the test media. Due to the statistical (or probabilistic) nature of sieving, each of these sized aluminium oxide samples may contain particles finer and coarser than the indicated sieve size.

**9.3.1.2** Pre-sieve aluminium oxide into individual fractions.

**9.3.1.3** Wash individual fractions of aluminium oxide by adding about 50 g of material to a container, adding distilled or deionized water, and shaking vigorously.

**9.3.1.4** Decant liquid and repeat the washing three times.

**9.3.1.5** Dry aluminium oxide for 8 h in an oven set between 105 °C (220 °F) and 120 °C (250 °F).

**9.3.1.6** Dry-sieve the aluminium oxide sample for 10 min in a stack of at least five consecutive test sieves containing at least two US sieve sizes finer and two US sieve sizes coarser than the indicated sieve size of the test screen.

**9.3.1.7** The amount sieved shall be limited to a range of 50 g to 60 g or less, because larger samples will result in more plugging and hold-up.

**9.3.1.8** If there is hold-up of fines due to plugging of the coarser sieves, remove each individual sieve fraction and collect it individually in a large container (see 9.2.9), then brush and clean the sieve over the same larger container. Then place the entire sieve fraction in a marked or labelled container. Repeat this procedure for each individual sieve fraction.

**9.3.1.9** Each individual fraction can then be placed back on the sieve from which the fraction was originally removed and dry-sieved again for 5 min. Repeat this procedure as many times as necessary to obtain an accurately-sized sieve fraction.

**9.3.1.10** The aluminium oxide fractions retained on each consecutive sieve shall be carefully removed and placed into individual marked or labelled containers.

#### 9.3.2 Preparation of sample for test range

**9.3.2.1** Using the aluminium oxide fractions obtained in accordance with 9.3.1, prepare combined aluminium oxide samples covering the range of screens to be tested.

Three examples of overlapping aluminium oxide samples covering API No. 30 to API No. 635 are given in Table 4.

Table 4 — Examples of sample preparation

API No.	Opening µm	Mass of test media I <sup>a</sup> g	Mass of test media II <sup>b</sup> g	Mass of test media III <sup>c</sup> g
25	710	0		
30	600	5,23		
35	500	5,46		
40	425	5,78		
45	325	5,45		
50	300	5,67		
60	250		0	
70	212		7,12	
80	180		7,23	
100	150		7,45	
120	125		7,57	0
140	106			8,78
170	90			8,12
200	75			8,23
230	63			8,34
270	53			8,45
325	45			
400	38			
450	32			
500	25			
635	20			
<b>Total mass, g</b>		27,59	36,71	41,92

<sup>a</sup> The distribution of aluminium oxide grit for test media I would be used for a sample test screen with openings between 325 µm and 500 µm.

<sup>b</sup> The distribution of aluminium oxide grit for test media II would be used for a sample test screen with openings between 125 µm and 180 µm.

<sup>c</sup> The distribution of aluminium oxide grit for test media III would be used for a sample test screen with openings between 53 µm and 75 µm.

**9.3.2.2** Table 4 distributions are meant to serve as examples only. For convenience, the number of sieves and the mass of aluminium oxide may be varied as follows:

- a) a minimum of four and a maximum of ten consecutive sieves with no test media added for the coarsest sieve, as shown in Table 4 in the three example distributions;
- b) a total of 5 g to 10 g of each size range can be mixed and added to the stack of test sieves with a total of 20 g to 80 g placed on the top screen before sieving. For a test to be valid, the test screen shall separate 10 % to 90 % of the test sample. If the loss during a test exceeds 1,0 g, the test is invalid and shall be repeated.

## 9.4 Preparation of test screen

**9.4.1** Mount the test screen so that all layers are in contact and tensioned to simulate the installation on a shaker.

**NOTE** If the screen cloth is not tensioned properly, erroneous results are obtained. For example, a triple-layer screen cloth has two fine screening layers that should be held in contact with one another to achieve this screen's benefits. If the two fine layers are not in contact, any beneficial effect on solids separation gained by having the two layers is lost. Any test results obtained with the two layers not held in contact are invalid or are not representative of the separation capability of the screen.

**9.4.2** Tension and mount all test screen samples in accordance with the manufacturer's specifications.

**9.4.3** Return any screen selected for tests to the manufacturer for test screen sample preparation with impartial third-party supervision.

**9.4.4** For screens with two or more layers, orient and mount the individual screen cloths relative to each other in the test screen sample in the same manner as an actual manufactured screen would be mounted on a shaker.

**9.4.5** The test screen holder shall be constructed of light-weight aluminium or PVC pipe in accordance with 8.3.3.

**9.4.6** Hold the test screen securely between the top and bottom parts which are designed to bolt together and to nest with a regular 8-in US test sieve.

**9.4.7** Place rubber gaskets or other sealing materials on the two sealing surfaces of the test screen holder, in order to contain all the test media inside the sieve stack. Seal any particle escape routes between the test screen sample and the sealing surfaces of the test screen holder.

**9.4.8** Centre the mounted test screen sample [for multi-layer screens, place the finer screen(s) uppermost] between the top and bottom parts of the test screen holder and bolt the parts securely together.

**9.4.9** The loss of 1,0 g or more of the test media invalidates the test results.

**9.4.10** Wash screens in a detergent solution to ensure that all oil is removed from the screens. Dry screen thoroughly before placing on the sieve shaker.

## 9.5 Test procedure

**9.5.1** Weigh 5 g to 8 g of sized aluminium oxide samples having four or five consecutive sizes. Record the sample masses to the nearest 0,01 g.

**9.5.2** Combine the sized samples, weigh to the nearest 0,01 g, and record the mass.

**9.5.3** Weigh and record the initial mass of each empty sieve corresponding to the sieve fractions included in the aluminium oxide sample.

**9.5.4** Weigh and record the initial mass of the empty sieve pan.

**9.5.5** Arrange the sieves with the coarsest on top and the finest on bottom. Place the test screen in the middle of the stack. Nest the sieve stack with the sieve pan on the bottom.

**9.5.6** Pour the combined sample onto the top sieve, place a sieve cover on top of the sieve stack, and secure in the sieve shaker.

**9.5.7** Mount the sieve stack securely in the sieve shaker, and allow to vibrate for 10 min as determined by a timer.

**9.5.8** Carefully remove the stack from the sieve shaker and separate the sieves. Weigh each sieve with the retained aluminium oxide.

## 9.6 Calculation of D100 separation for test screen cloth

**9.6.1** Calculate the mass of aluminium oxide retained on each sieve by subtracting the initial empty sieve mass (see 9.5.3) from the final sieve mass, including the retained aluminium oxide. Record each mass with the corresponding sieve size.

**9.6.2** Calculate the cumulative mass of aluminium oxide retained on each sieve, from the smallest opening size to the largest.

**9.6.3** Confirm that the test media contains solids coarser than the test screen and finer than the test screen.

**9.6.4** Plot the cumulative mass on all sieves as a function of the screen opening size.

**9.6.5** Determine the equation of a straight line connecting the two data points on either side of the test screen cumulative mass.

**9.6.6** Using the cumulative mass captured on the test screen, determine the equivalent opening size, graphically or with the equation determined in 9.6.5. This is the D100 separation for the test screen and is used to identify the screen designation.

**9.6.7** Repeat the procedure three times. Calculate the average D100 separation for the three tests.

**9.6.8** If the individual results from the three tests differ by more than the error permitted in a screen specification, the test is invalid and shall be repeated.

**9.6.9** When the D100 separation falls at a point which is half or less of the difference between the openings of a finer and the next coarser sieve, the test screen is rated as the finer test sieve.

When the D100 separation falls at a point which is more than half of the difference between the openings of a finer and the next coarser sieve, the test screen is rated as the coarser sieve.

An example of the rating is if the D100 separation is between a US 170 (90  $\mu\text{m}$ ) and a US 200 (75  $\mu\text{m}$ ) sieve size; the test screen is rated as an API 170 if the D100 separation is greater than 82,5  $\mu\text{m}$  and an API 200 if the D100 separation is 82,5  $\mu\text{m}$  or less.

**9.6.10** Table 5 lists the D100 separation and the corresponding API screen number.

**9.6.11** The following is a sample calculation of API screen number.

- About 5 g to 6 g of aluminium oxide sized between 63  $\mu\text{m}$  and 125  $\mu\text{m}$  is placed on a stack of sieves with an unknown size test screen,  $x$ , below the 106  $\mu\text{m}$  (API 140) sieve. After 10 min of shaking on the sieve shaker, the sieves were weighed and the mass of aluminium oxide on each screen calculated from the difference in masses of the empty sieve and the sieve after shaking. See Table 6.
- The mass captured on the unknown screen (13,4 g) indicates that the D100 separation of the unknown screen is between 90  $\mu\text{m}$  (API 170) and 106  $\mu\text{m}$  (API 140). See Figure 3.
- With the data points of 9,99 g on the 106  $\mu\text{m}$  (API 140) sieve and the 16,01 g on the 90  $\mu\text{m}$  (API 170) sieve, an equation can be derived to describe a straight line between these two data points. See Figure 4.
- This equation indicates that the cumulative mass retained is equal to  $-0,376 2$  times the opening size, in micrometres, plus 49,872. The cumulative mass captured on the unknown screen was 13,40 g. Solving the equation for  $x$  when  $y = 13,40$ , the opening size is 96,9  $\mu\text{m}$ . See Figure 5.

— Referring to 9.6.9, the API screen number for the D100 separation is greater than 82,5 µm and smaller than 98,0 µm. The new screen number would be API 170 (97,0 µm).

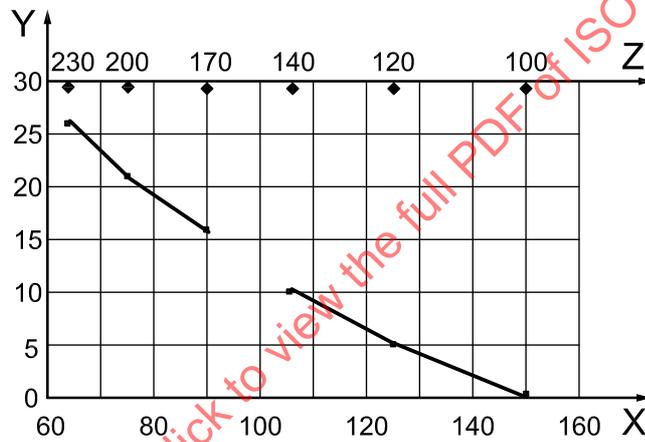
**Table 5 — D100 separation and API screen number**

D100 separation µm	API screen number
> 3 075,0 to 3 675,0	API 6
> 2 580,0 to 3 075,0	API 7
> 2 180,0 to 2 580,0	API 8
> 1 850,0 to 2 180,0	API 10
> 1 550,0 to 1 850,0	API 12
> 1 290,0 to 1 550,0	API 14
> 1 090,0 to 1 290,0	API 16
> 925,0 to 1 090,0	API 18
> 780,0 to 925,0	API 20
> 655,0 to 780,0	API 25
> 550,0 to 655,0	API 30
> 462,5 to 550,0	API 35
> 390,0 to 462,5	API 40
> 327,5 to 390,0	API 45
> 275,0 to 327,5	API 50
> 231,0 to 275,0	API 60
> 196,0 to 231,0	API 70
> 165,0 to 196,0	API 80
> 137,5 to 165,0	API 100
> 116,5 to 137,5	API 120
> 98,0 to 116,5	API 140
> 82,5 to 98,0	API 170
> 69,0 to 82,5	API 200
> 58,0 to 69,0	API 230
> 49,0 to 58,0	API 270
> 41,5 to 49,0	API 325
> 35,0 to 41,5	API 400
> 28,5 to 35,0	API 450
> 22,5 to 28,5	API 500
> 18,5 to 22,5	API 635

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Table 6 — Experimental results

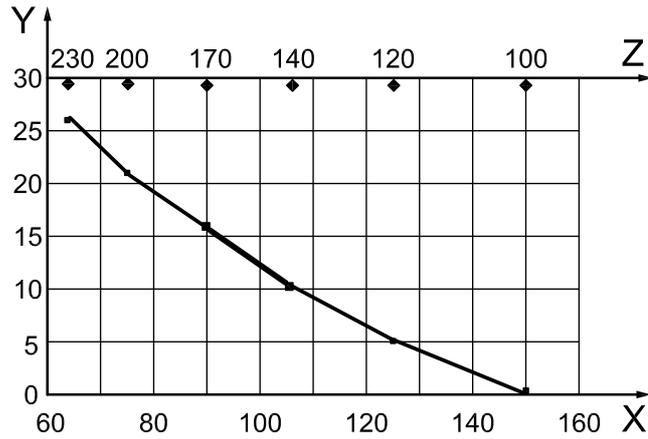
API number	Opening size µm	Retained AIO mass g	Cumulative retained AIO g
100	150	0	0
120	125	5,01	5,01
140	106	4,98	9,99
x	?	3,41	13,40
170	90	2,61	16,01
200	75	5,02	21,03
230	63	4,98	26,01
		26,01	



**Key**

- X opening size, µm
- Y cumulative mass retained, g
- Z API number

Figure 3 — Sieve analysis with unknown sieve

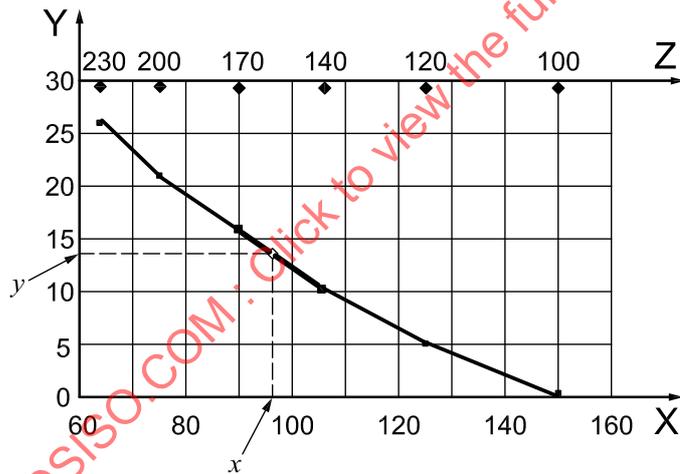


$$y = -0,376 2 x + 49,872$$

**Key**

- X opening size, μm
- Y cumulative mass retained, g
- Z API number

**Figure 4 — Unknown sieve size analysis**



$$y = -0,376 2 x + 49,872 \quad y = 13,40 \text{ g}; x = 97 \text{ } \mu\text{m}$$

**Key**

- X opening size, μm
- Y cumulative mass retained, g
- Z API number

**Figure 5 — Unknown sieve marking decision**

## 10 Non-blanked area of shale shaker screen panel

### 10.1 Principle

This procedure is a method for determining the total non-blanked area of a shale shaker screen panel using direct measurement and calculation techniques.

## 10.2 Apparatus

**10.2.1 Calliper**, dial or digital, graduated in millimetres to measure smaller perforated panel or pretensioned panel openings.

**10.2.2 Ruler**, marked in millimetres, to measure larger open-hook strip-type panels.

## 10.3 Procedure for pretensioned or perforated panel-type screens

**10.3.1** Obtain data from and make all calculations with information gathered from “ordinary” or “regular” production-run screen panels. Do not use “show,” “test” or “special” panels.

**10.3.2** Randomly choose two panels from a production run of at least 25 screened panels.

**10.3.3** Mark all panel openings for measurement, and number the openings consecutively.

**10.3.4** Measure the necessary dimensions of each panel opening to the nearest millimetre. These measurements are critical to obtain accurate and repeatable results. Do not include the space occupied by adhesive or bonding materials. Measure only the unoccluded panel opening space located between the panel webs.

## 10.4 Calculation for pretensioned or perforated panel-type screens

**10.4.1** Calculate the area of each panel opening, in square millimetres.

**10.4.2** Sum the unoccluded areas of all panel openings to obtain the total non-blanked area of that particular panel, in square millimetres.

If necessary, convert the total non-blanked area from square millimetres to square feet by dividing by 92 903.

**10.4.3** Calculate the average non-blanked panel area by summing the total non-blanked areas of both randomly chosen panels and dividing by 2.

## 10.5 Procedure for open-hook strip panels

**10.5.1** Obtain data from and make all calculations with information gathered from “ordinary or regular” production-run screen panels. Do not use “show,” “test,” or “special” panels.

**10.5.2** Randomly choose two panels from a production run of at least 25 screened panels.

**10.5.3** Measure the width of each screen panel from the inner edge of the hoop strips on either side, to the nearest millimetre.

**10.5.4** Measure the length of each screen panel from the inside of the top of the non-blanked wire cloth area to the inside of the bottom of the non-blanked cloth area, to the nearest millimetre.

## 10.6 Calculation for open-hook strip panels

**10.6.1** Calculate the total non-blanked area of each panel, in square millimetres.

If necessary, convert the total non-blanked area from square millimetres to square feet by dividing by 92 903.

**10.6.2** Calculate the average non-blanked panel area by summing the total non-blanked areas of both randomly chosen panels and dividing by 2.

**10.7 Example calculation of total non-blanked area for a panel-mount screen**

**10.7.1** Measure the length and width of a panel opening with a dial or digital calliper to the nearest millimetre and calculate its area. If, for example, it measures 24 mm wide by 25 mm long, its area is as follows:

$$24 \text{ mm} \times 25 \text{ mm} = 600 \text{ mm}^2$$

**10.7.2** Perform a similar calculation for all panel openings on both screens used in the analysis. Sum the individual results to obtain the total non-blanked area of each panel-mount screen, in square millimetres. In one set of calculations, the resultants sums are:

$$626\,400 \text{ mm}^2 \text{ and } 618\,734 \text{ mm}^2, \text{ or } 0,626 \text{ m}^2 \text{ and } 0,618 \text{ m}^2$$

If necessary, convert the total non-blanked area to square feet by using the conversion factor.

$$626\,400 \text{ mm}^2 / 92\,903 = 6,74 \text{ ft}^2$$

$$618\,734 \text{ mm}^2 / 92\,903 = 6,66 \text{ ft}^2$$

**10.7.3** Average the two non-blanked area results to obtain the final answer for total non-blanked area of a panel.

$$[(0,626 \text{ m}^2) + (0,618 \text{ m}^2)]/2 = 0,622 \text{ m}^2$$

If using square feet:

$$[(6,74 \text{ ft}^2) + (6,66 \text{ ft}^2)]/2 = 6,70 \text{ ft}^2$$

NOTE The total non-blanked area for an open-hook strip screen panel is calculated as follows.

- a) Measure the width of each screen panel from the inner edge of the hook strips on either side.
- b) Measure the length of the non-blanked area of each screen panel, starting from inside edge of the top cloth fold and extending to the inside edge of the bottom cloth fold.
- c) Calculate the total non-blanked area, in square millimetres, of each screen panel:

— screen panel #1:  $1\,160 \text{ mm} \times 1\,520 \text{ mm} = 1\,763\,200 \text{ mm}^2 = 1,763 \text{ m}^2$

— screen panel #2:  $1\,156 \text{ mm} \times 1\,522 \text{ mm} = 1\,759\,432 \text{ mm}^2 = 1,759 \text{ m}^2$

If necessary, convert the total non-blanked area of each screen panel from square millimetres to square feet by performing the following calculation:

— screen panel #1:  $1\,763\,200 \text{ mm}^2 / 92\,903 = 18,98 \text{ ft}^2$

— screen panel #2:  $1\,759\,432 \text{ mm}^2 / 92\,903 = 18,94 \text{ ft}^2$

- d) Average the two non-blanked panel area results to obtain the final answer for the total non-blanked area of one open hook strip panel:

$$(1,763 \text{ m}^2 + 1,759 \text{ m}^2) / 2 = 1,761 \text{ m}^2$$

If necessary, calculate the average in square feet:

$$(18,98 \text{ ft}^2 + 18,94 \text{ ft}^2) / 2 = 18,96 \text{ ft}^2$$