

Rheology and Hydraulics of Oil-well Drilling Fluids

API RECOMMENDED PRACTICE 13D
SEVENTH EDITION, SEPTEMBER 2017

REAFFIRMED, MAY 2023



American
Petroleum
Institute

Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

Users of this recommended practice should not rely exclusively on the information contained in this document.

Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

All rights reserved. No part of this work may be reproduced, translated, stored in a retrieval system, or transmitted by any means, electronic, mechanical, photocopying, recording, or otherwise, without prior written permission from the publisher. Contact the Publisher, API Publishing Services, 200 Massachusetts Avenue, NW, Washington, DC 20001.

Copyright © 2017 American Petroleum Institute

Foreword

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

Shall: As used in a standard, “shall” denotes a minimum requirement in order to conform to the specification.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required in order to conform to the specification.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 200 Massachusetts Avenue, NW, Washington, DC 20001. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 200 Massachusetts Avenue, NW, Washington, DC 20001.

Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Washington, DC 20001, standards@api.org.

Contents

Page

1	Scope	1
2	Normative References	2
3	Acronyms, Abbreviations, Symbols, Definitions, and Units	2
4	Fluid Flow Fundamentals and Rheological Models	9
4.1	Flow Fundamentals and Rheological Models	9
4.2	Viscosity	10
4.3	Shear Stress	11
4.4	Shear Rate	13
4.5	Shear Stress/Shear Rate Relationship	14
4.6	Fluid Characterization	14
4.7	Newtonian Fluids	14
4.8	Non-Newtonian Fluids	15
4.9	Rheological Models	15
5	Rheological Parameters	17
5.1	Measurement of Rheological Parameters	17
5.2	Rheological Models	19
6	Prediction of Downhole Behavior of Drilling Fluids	22
6.1	Principle	22
6.2	Temperature Predictions of Circulating Drilling Fluids	22
6.3	Prediction of Downhole Rheological Properties	24
6.4	Prediction of Downhole Density	26
7	Pressure-loss Modeling	30
7.1	Principle	30
7.2	Basic Relationships	30
7.3	Surface-connection Pressure Loss	31
7.4	Drill-string and Annular Frictional Pressure Loss	32
7.5	Bit Pressure Loss	39
7.6	Downhole-tools Pressure Loss	39
7.7	Choke-line Pressure Loss	40
7.8	Casing Pressure	40
7.9	Equivalent Circulating Density	40
8	Swab/Surge Pressures	41
8.1	Principle	41
8.2	Controlling Parameters	42
8.3	Closed-string Procedure	44
8.4	Open-string Procedure	45
8.5	Transient Swab/Surge Analysis	45
9	Hole Cleaning	45
9.1	Description of the Challenge	45
9.2	Hole-cleaning Practices and Remedial Options	45
9.3	Cuttings Transport	47
9.4	Modeling Hole Cleaning in Vertical and Low-angle Wells	49
9.5	Modeling Hole Cleaning in Directional Wells	51
9.6	Weight-material Sag	54

Contents

	Page
10 Hydraulics Optimization	55
10.1 Optimization Objectives	55
10.2 Calculations	56
10.3 Reaming While Drilling with Pilot-bit Configuration	58
10.4 Bit-nozzle Selection.	59
10.5 Pump-off Pressure/Force	59
11 Rigsite Monitoring	59
11.1 Introduction	59
11.2 Annular Pressure-loss Measurement	59
11.3 Validation of Hydraulics Models	63
11.4 Interpretation of Downhole Pressure Measurements	64
Annex A (informative) Worked Example Parameters	66
Annex B (informative) Downhole-properties Example	68
Annex C (informative) Pressure-loss Example	72
Annex D (informative) Swab/Surge-pressures Example	74
Annex E (informative) Hole-cleaning Example	76
Annex F (informative) Hydraulics-optimization Example	79
Bibliography	83
Figures	
1 Parallel Plates with Fluid-filled Gap Showing Effects of Upper Plate Sliding Past Lower Plate	11
2 Rheograms of Three Rheological Models on Rectangular Coordinates	16
3 Couette-type, Mechanical Rotational Viscometer with Dial Readout	18
4 Viscosity of Several Base Fluids as Function of Temperature	25
5 Isothermal Plot of a 15.3 lbm/gal Synthetic-based Drilling Fluid.	27
6 Cuttings Transport Mechanisms in Vertical and Deviated Wells.	48
7 Effect of Yield Point on Critical Flow Rate	52
8 Rheology Factor Chart for 8 1/2-in. Holes	53
9 Hole-cleaning Chart for 8 1/2-in. Holes	53
10 Optimizing Maximum Impact Force	58
11 Drilling Pressure Window	60
12 Time-based Log Format	62
13 Cuttings Mobilization	64
A.1 Wellbore Profile Schematic	67
E.1 Rheology Factor Chart for 8 1/2-in. Holes	77
E.2 Hole-cleaning Chart for 8 1/2-in. Holes	78
F.1 Wellsite Nozzle Test.	80
F.2 On-site Nozzle Test for Maximum Hydraulic Impact Force	81
Tables	
1 Acronyms and Abbreviations	2
2 Symbols, Definitions, and Units	4
3 Types of Viscometers for Measuring Drilling Fluid Rheological Properties	19
4 Example HTHP Viscometer Test Matrix	25
5 Temperature and Pressure Coefficients for Determining Fluid Density Using Equation (42)	29
6 CSC Values for Surface-connection Cases	32

Contents

	Page
7 Example Hole Cleaning Operational Practices	46
8 Hydraulic Optimization Equations.....	57
9 Interpretation Guide	65
B.1 Hydraulic Data by Section	68
B.2 Downhole Density Calculations Under Static and Dynamic Conditions	69
B.3 Test Matrix for HTHP Viscometer Data	70
B.4 Results for Different Rheological Models.....	70
B.5 Herschel-Bulkley Parameters (Numerical Method)	70
B.6 Herschel-Bulkley Parameters (Measurement Method)	70
B.7 Bingham Plastic Parameters	71
C.1 Spreadsheet Data of Pressure Loss in Drill String	72
C.2 Spreadsheet Data of Pressure Loss in Annulus	73
C.3 Data for Pressure Losses vs Flow Rate	73
D.1 Closed-string Example	74
D.2 Open-string Example	75
D.3 Iterative Process for the Open-string Example	75
F.1 Rig Data for Flow Rate and Standpipe Pressure	79
F.2 Calculated System Parasitic Pressure Loss	80
F.3 Impact Force Methods Comparison	82

Rheology and Hydraulics of Oil-well Drilling Fluids

1 Scope

1.1 The objective of this recommended practice (RP) is to provide a basic understanding of and guidance about drilling fluid rheology and hydraulics to assist with drilling wells of various complexities, including high-temperature/high-pressure (HTHP), extended-reach drilling (ERD), and highly directional wells.

1.2 Office and wellsite engineers are the target audience for this document. The complexity of the equations provided is such that a competent engineer can use simple spreadsheet programs to conduct analyses. Given that the equations used herein are constrained by this spreadsheet limitation, more advanced numerical solutions containing multiple subroutines and macros are not offered. This limitation does not suggest that only the results given by the spreadsheet methods are valid engineering solutions.

1.3 Rheology is the study of the deformation and flow of matter. For this document, rheology is the study of the flow characteristics of drilling fluids and how these characteristics affect movement of the fluids. The discussion of rheology in this document is limited to single-phase liquid flow.

1.4 Rheological properties directly affect flow characteristics and hydraulic behavior. Properties must be controlled for drilling fluids to perform their various functions. Certain properties are measured at the wellsite for monitoring and treatment and in the laboratory for development of new additives and systems, formulation for specific applications, and diagnosis of special problems.

1.5 Measurement of rheological properties also makes possible mathematical descriptions of circulating fluid flow important for the following hydraulics-related determinations:

- a) calculating frictional pressure losses in pipes and annuli,
- b) determining equivalent circulating density (ECD) of the drilling fluid under downhole conditions,
- c) determining flow regimes,
- d) estimating hole-cleaning efficiency,
- e) estimating swab/surge pressures, and
- f) optimizing the drilling fluid circulating system to improve drilling efficiency.

1.6 The concepts of viscosity, shear stress, and shear rate are important in understanding the flow characteristics of fluids. Specific measurements are made on fluids to determine rheological parameters under a variety of conditions. From this information, the circulating system can be designed and evaluated to accomplish desired objectives.

1.7 Drilling fluid hydraulics involves hydrostatic pressures, frictional pressure losses, carrying capacity, swab/surge pressures, and equivalent static and circulating densities, among others. Mathematical models relating shear stress to shear rate and formulas for estimating drilling fluid hydraulics are included. Calculation methods used herein consider the effects of temperature and pressure on drilling fluid rheology and density.

1.8 The U.S. customary (USC) unit system is used in this RP. However, any consistent system of units may be used where so indicated, as in the development of equations in Section 4. The term “pressure” means “gauge pressure” unless otherwise noted.

NOTE The term “consistent units” refers to a set of units that does not require an extra conversion factor to complete a calculation. In consistent International System of units (SI unit), time is expressed in seconds (s), length in meters (m), mass in kilograms (kg), force in newtons (N), temperature in degrees Celsius (°C), and absolute temperature in kelvins (K).

In USC units , time is expressed in seconds (s), length in feet (ft), mass in pound mass (lbm), force in pound force (lbf), temperature in degrees Fahrenheit (°F), and absolute temperature in degrees Rankine (°R).

1.9 Factors included in Section 3, Table 2 permit conversions of USC units to SI units or SI units to USC units.

1.10 Annexes A through F contain example calculations to illustrate how equations contained within the document can be used to model a sample well. Step-by-step procedures are not included for every case; however, final results serve as benchmarks to replicate given cases.

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.

API Recommended Practice 13B-1, *Recommended Practice for Field Testing Water-based Drilling Fluids*

API Recommended Practice 13B-2, *Recommended Practice for Field Testing Oil-based Drilling Fluids*

3 Acronyms, Abbreviations, Symbols, Definitions, and Units

Table 1—Acronyms and Abbreviations

Abbreviation	Definition
BHA	bottomhole assembly
BOP	blowout preventer
CCI	carrying capacity index
DIN	German Institute for Standardization
ECD	equivalent circulating density
EDD	equivalent dynamic density
EMW	equivalent mud weight
ERD	extended-reach drilling
ESD	equivalent static density
H-B	Herschel–Bulkley
HHP	hydraulic horsepower
HPO	hydraulic pump-off force
HSI	hydraulic horsepower per square inch
HTHP	high-temperature/high-pressure
ID	internal diameter
LCM	lost circulation material
LOT	leak-off test
LSYP	low shear rate yield point
MD	measured depth
MWD	measurement while drilling
OD	outside diameter
PDC	polycrystalline diamond compact (cutter)
PDM	positive-displacement motor

Abbreviation	Definition
POI	point of interest
PVT	pressure, volume and temperature
RCD	rotating control device
RF	rheology factor
ROP	rate of penetration
RP	Recommended practice
RSS	rotary steerable system
RWD	ream while drilling
R#B#	viscometer rotor (#) and bob (#) combination
SPP	system parasitic pressure
TFA	total flow area
TI	transport index
TD	total depth
TVD	true vertical depth

Table 2—Symbols, Definitions, and Units

Symbol	Definition	U.S. Customary Units	Conversion Factor ^a	SI Units (base or derived)
a	Blasius form of friction-factor equation numerator	—	—	—
A	Surface area	in. ²	645.16E	mm ²
a_1	Density correction coefficient for pressure	lbm/gal	119.83	kg/m ³
a_2	Density correction coefficient for temperature	(lbm/gal)/°F	215.69	(kg/m ³)/°C
a_{ds}	Pipe acceleration	ft/s ²	0.3048	m/s ²
B_a	Well geometry correction factor	—	—	—
B_x	Viscometer geometry correction factor	—	—	—
b	Exponent in Blasius form of friction-factor equation	—	—	—
b_1	Density correction coefficient for pressure	(lbm/gal)/(lbf/in. ²)	0.017379	(kg/m ³)/Pa
b_2	Density correction coefficient for temperature	[(lbm/gal)/(lbf/in. ²)]/°F	0.031283	[(kg/m ³)/Pa]/°C
C_d	Jet nozzle discharge coefficient	—	—	—
C_{dt}	Proportionality constant for downhole tool pressure loss	—	—	—
C_g	Drilling fluid clinging factor on pipe for surge/swab operations	—	—	—
C_{sc}	Proportionality constant for surface-connection pressure loss	—	—	—
CCI	Carrying capacity index	—	—	—
c_a	In situ cuttings volume concentration	decimal fraction	—	decimal fraction
c_1	Density correction coefficient for pressure	(lbm/gal)/(lbf/in. ²) ²	2.5206E-06	(kg/m ³)/Pa ²
c_2	Density correction coefficient for temperature	[(lbm/gal)/(lbf/in. ²) ²]/°F	4.5370E-06	[(kg/m ³)/Pa ²]/°C
D_{td}	Total depth (measured)	ft	0.3048	m
D_{tvd}	True vertical depth	ft	0.3048	m
D_w	Water depth	ft	0.3048	m
d	Diameter	in.	25.4	mm
d_b	Bit diameter	in.	25.4	mm
d_c	Cuttings diameter	in.	25.4	mm
d_h	Hole diameter or casing inside diameter	in.	25.4	mm
d_{hyd}	Hydraulic diameter	in.	25.4	mm
d_i	Pipe internal diameter	in.	25.4	mm
d_n	Bit nozzle diameter	¹ / ₃₂ in.	0.79375	mm
d_{ni}	Diameter of i^{th} bit nozzle	¹ / ₃₂ in.	0.79375	mm
d_p	Pipe outside diameter	in.	25.4	mm

^a Conversion Factor is a divider to convert data expressed in SI base or derived units into a value expressed in USC units. It is a multiplier to convert data expressed in USC units into a value expressed in SI base or derived values.

Symbol	Definition	U.S. Customary Units	Conversion Factor ^a	SI Units (base or derived)
ECD	Equivalent circulating density	lbm/gal	119.8264	kg/m ³
EDD	Equivalent dynamic density	lbm/gal	119.8264	kg/m ³
$EDD_{D_{tvd}}$	Equivalent dynamic density at true vertical depth	lbm/gal	119.8264	kg/m ³
EDD_{td}	Equivalent dynamic density at total depth	lbm/gal	119.8264	kg/m ³
EMW	Equivalent mud weight	lbm/gal	119.8264	kg/m ³
ESD	Equivalent static density	lbm/gal	119.8264	kg/m ³
ESD_{D+L}	Equivalent static density at depth $D + L$	lbm/gal	119.8264	kg/m ³
$ESD_{D_{tvd}}$	Equivalent static density at true vertical depth	lbm/gal	119.8264	kg/m ³
ESD_a	Equivalent static density in annulus	lbm/gal	119.8264	kg/m ³
ESD_p	Equivalent static density in pipe (drill string)	lbm/gal	119.8264	kg/m ³
ESD_{td}	Equivalent static density at total depth	lbm/gal	119.8264	kg/m ³
e	Eccentricity	decimal fraction	—	decimal fraction
F	Force	lbf	4.448222	N
F_j	Jet impact force	lbf	4.448222	N
f	Fanning friction factor	—	—	—
f_{int}	Intermediate friction factor, transitional and turbulent flow	—	—	—
f_{lam}	Friction factor, laminar flow	—	—	—
f_{trans}	Friction factor, transitional flow	—	—	—
f_{turb}	Friction factor, turbulent flow	—	—	—
G_{10m}	10-min gel strength	lbf/100 ft ²	0.4788026	Pa
G_{10s}	10-s gel strength	lbf/100 ft ²	0.4788026	Pa
G_{30m}	30-min gel strength	lbf/100 ft ²	0.4788026	Pa
G_t	Geometry factor	—	—	—
G_p	Geometry shear rate correction factor (power law)	—	—	—
HHP_b	Hydraulic horsepower at the bit	hp	0.746043	kW
HHP_{max}	Maximum hydraulic horsepower	hp	0.746043	kW
HPO	Hydraulic pump-off force	1000 lbf	4.448222	kN
HSI	hydraulic horsepower per square inch	hp/in. ²	1.15637	W/mm ²
h	Distance between two parallel plates or layers	in.	25.4	mm
h_c	Cutting thickness	in.	25.4	mm
IF	Jet impact force	lbf	4.448222	N
K_x	System parasitic pressure loss coefficient	(lbf/in. ²)/(gal/min) ^u	6.894757	kPa/(3.78541 L/min) ^u

^a Conversion Factor is a divider to convert data expressed in SI base or derived units into a value expressed in USC units. It is a multiplier to convert data expressed in USC units into a value expressed in SI base or derived values.

Symbol	Definition	U.S. Customary Units	Conversion Factor ^a	SI Units (base or derived)
k	Consistency factor (Herschel–Bulkley)	$\text{lbf}\cdot\text{s}^n/100\text{ ft}^2$	478.803	$\text{mPa}\cdot\text{s}^n$
k_1	Power law viscosity at 1 s^{-1}	cP	1.0	$\text{mPa}\cdot\text{s}$
k_p	Power law and high shear rate consistency factor	$\text{lbf}\cdot\text{s}^{n_p}/100\text{ ft}^2$	478.803	$\text{mPa}\cdot\text{s}^{n_p}$
L	Length of drill string (pipe) or annular segment	ft	0.3048	m
$LSYP$	Low shear rate yield point	$\text{lbf}/100\text{ ft}^2$	0.4788026	Pa
N_{cRe}	Critical Reynolds number	—	—	—
N_{Re}	Reynolds number	—	—	—
N_{ReG}	Generalized Reynolds number	—	—	—
n	Flow behavior index (Herschel–Bulkley)	—	—	—
n_p	Flow behavior index (power law)	—	—	—
P	Pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_a	Annular pressure loss	$\text{lbf}/\text{in.}^2$	6.894757	kPa
$P_{a-\text{min}}$	Minimum annular pressure loss to break mud gel	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_b	Bit pressure loss	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{bh}	Bottomhole pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
$P_{b\text{opt}}$	Optimum pressure loss across bit	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_c	Casing pressure, back pressure on annulus	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{cs}	Shut-in casing pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{cl}	Choke line pressure loss	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{ds}	Drill string pressure loss	$\text{lbf}/\text{in.}^2$	6.894757	kPa
$P_{ds-\text{min}}$	Minimum drill string pressure loss to break mud gel	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{dt}	Downhole tools + motors pressure loss	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_f	Formation pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{ha}	Annular hydrostatic pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{hd}	Drill string hydrostatic pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{max}	Maximum pump (standpipe) pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_p	Pump (standpipe) pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{sc}	Surface-connections pressure loss	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_{ss}	Surge/swab pressure	$\text{lbf}/\text{in.}^2$	6.894757	kPa
P_x	System parasitic pressure losses	$\text{lbf}/\text{in.}^2$	6.894757	kPa
PV	Plastic viscosity (Bingham)	cP	1.0	$\text{mPa}\cdot\text{s}$
Q	Flow rate	gal/min	3.785412	l/min
Q_c	Critical flow rate (laminar to transitional flow)	gal/min	3.785412	l/min

^a Conversion Factor is a divider to convert data expressed in SI base or derived units into a value expressed in USC units. It is a multiplier to convert data expressed in USC units into a value expressed in SI base or derived values.

Symbol	Definition	U.S. Customary Units	Conversion Factor ^a	SI Units (base or derived)
Q_{crit}	Critical flow rate for optimized hydraulics	gal/min	3.785412	l/min
Q_{opt}	Optimum flow rate	gal/min	3.785412	l/min
R	Ratio of yield stress/yield point (τ_y/YP)	decimal fraction	—	decimal fraction
R_3	Viscometer reading at 3 r/min	°	—	°
R_6	Viscometer reading at 6 r/min	°	—	°
R_{100}	Viscometer reading at 100 r/min	°	—	°
R_{200}	Viscometer reading at 200 r/min	°	—	°
R_{300}	Viscometer reading at 300 r/min	°	—	°
R_{600}	Viscometer reading at 600 r/min	°	—	°
R_{lam}	Eccentric annulus laminar pressure ratio	decimal fraction	—	decimal fraction
R_t	Cuttings transport ratio	decimal fraction	—	decimal fraction
R_{turb}	Eccentric annulus turbulent pressure ratio	decimal fraction	—	decimal fraction
RF	Rheology factor	—	—	—
ROP	Rate of penetration	ft/h	0.3048	m/h
T	Temperature	°F	(°F – 32)/1.8	°C
T_{bhc}	Bottomhole circulating temperature	°F	(°F – 32)/1.8	°C
T_{bhs}	Bottomhole static temperature	°F	(°F – 32)/1.8	°C
T_{fL}	Flowline temperature	°F	(°F – 32)/1.8	°C
T_{ml}	Temperature at the mudline	°F	(°F – 32)/1.8	°C
T_0	Surface temperature at 50-ft depth	°F	(°F – 32)/1.8	°C
TFA	Total flow area	in. ²	645.16	mm ²
TI	Transport index	—	—	—
u	Slope of logarithmic system parasitic pressure loss	—	—	—
V	Flow velocity (average)	ft/min	0.3048	m/min
V_a	Fluid velocity in annulus (average)	ft/min	0.3048	m/min
V_c	Critical velocity	ft/min	0.3048	m/min
V_{cb}	Critical velocity (Bingham plastic fluids)	ft/min	0.3048	m/min
V_{cp}	Critical velocity (power law fluids)	ft/min	0.3048	m/min
V_{ds}	Drill string (pipe) velocity for surge/swab	ft/min	0.3048	m/min
V_{eff}	Effective annular fluid velocity due to pipe movement	ft/min	0.3048	m/min
V_j	Jet (nozzle) velocity	ft/s	0.3048	m/s
V_p	Fluid velocity inside pipe (average)	ft/min	0.3048	m/min
V_s	Cuttings slip velocity	ft/min	0.3048	m/min
V_u	Cuttings net upward velocity	ft/min	0.3048	m/min
$Vol\%$	Volume percent	%	—	%

^a Conversion Factor is a divider to convert data expressed in SI base or derived units into a value expressed in USC units. It is a multiplier to convert data expressed in USC units into a value expressed in SI base or derived values.

Symbol	Definition	U.S. Customary Units	Conversion Factor ^a	SI Units (base or derived)
Vol_{wb}	Volume of wellbore	bbl	0.1589873	m^3
w_{CaCl_2}	Aqueous phase mass fraction of calcium chloride	wt%	—	wt%
x	Viscometer diameter ratio (rotor/bob)	—	—	—
YP	Yield point (Bingham)	lbf/100 ft ²	0.4788026	Pa
α	Geometry factor	—	—	—
β	Intermediate parameter for critical velocity calculation	—	—	—
$\dot{\gamma}$	Shear rate	s^{-1}	—	s^{-1}
$\dot{\gamma}_b$	Cuttings (particulate) shear rate for $N_{Re} = 100$	s^{-1}	—	s^{-1}
$\dot{\gamma}_c$	Cuttings shear rate	s^{-1}	—	s^{-1}
$\dot{\gamma}_i$	Iterative shear rate used in curve-fit method	s^{-1}	—	s^{-1}
$\dot{\gamma}_s$	Cuttings (particle) shear rate	s^{-1}	—	s^{-1}
$\dot{\gamma}_w$	Shear rate at the wall	s^{-1}	—	s^{-1}
$\dot{\gamma}_{wa}$	Shear rate at the annulus wall	s^{-1}	—	s^{-1}
$\dot{\gamma}_{wp}$	Shear rate at the pipe wall	s^{-1}	—	s^{-1}
Δ	Change in value when preceding a variable	—	—	—
μ	Viscosity	cP	1.0	mPa•s
ϕ_{base}	Volume fraction of base fluid	decimal fraction	—	decimal fraction
ϕ_{brine}	Volume fraction of brine	decimal fraction	—	decimal fraction
$\phi_{CaCl_2, brine}$	Volume fraction of salt in a CaCl ₂ brine	decimal fraction	—	decimal fraction
ϕ_{ds}	Volume fraction of dried retort solids	decimal fraction	—	decimal fraction
ϕ_{salt}	Volume fraction of salt (soluble)	decimal fraction	—	decimal fraction
ϕ_{solids}	Volume fraction of solids (suspended solids)	decimal fraction	—	decimal fraction
ϕ_{total}	Volume fraction of all components	decimal fraction	—	decimal fraction
ϕ_{water}	Volume fraction of water	decimal fraction	—	decimal fraction
ρ	Fluid density	lbm/gal	119.8264	kg/m^3
$\rho_{(P,T)}$	Fluid density at pressure P and temperature T	lbm/gal	119.8264	kg/m^3
ρ_a	Fluid density in annulus (local)	lbm/gal	119.8264	kg/m^3
ρ_b	Fluid density through bit nozzles	lbm/gal	119.8264	kg/m^3
ρ_{base}	Base fluid density	lbm/gal	119.8264	kg/m^3
$\rho_{base-P,T}$	Base fluid density at pressure P and temperature T	lbm/gal	119.8264	kg/m^3
ρ_{brine}	Brine density	lbm/gal	119.8264	kg/m^3
$\rho_{brine-P,T}$	Brine density at pressure P , temperature T	lbm/gal	119.8264	kg/m^3

^a Conversion Factor is a divider to convert data expressed in SI base or derived units into a value expressed in USC units. It is a multiplier to convert data expressed in USC units into a value expressed in SI base or derived values.

Symbol	Definition	U.S. Customary Units	Conversion Factor ^a	SI Units (base or derived)
ρ_c	Cutting (particle) relative density (specific gravity)	—	—	—
ρ_{dt}	Reference drilling fluid density used for empirical downhole tools pressure loss	lbm/gal	119.8264	kg/m ³
ρ_l	Drilling fluid density (local)	lbm/gal	119.8264	kg/m ³
ρ_p	Drilling fluid density in drill string (local)	lbm/gal	119.8264	kg/m ³
ρ_s	Drilling fluid density at surface	lbm/gal	119.8264	kg/m ³
ρ_{solids}	Solids density (suspended solids)	lbm/gal	119.8264	kg/m ³
ρ_{total}	Total density	lbm/gal	119.8264	kg/m ³
ρ_{water}	Water density	lbm/gal	119.8264	kg/m ³
τ	Shear stress	lbf/100 ft ²	0.4788026	Pa
τ_c	Shear stress due to particle (cuttings) slip	lbf/100 ft ²	0.4788026	Pa
τ_i	Iterative shear stress in curve-fit method	lbf/100 ft ²	0.4788026	Pa
τ_v	Rotational coaxial-cylinder viscometer dial reading	°	—	°
τ_w	Shear stress at the wall	lbf/100 ft ²	0.4788026	Pa
τ_y	Yield stress (Herschel–Bulkley)	lbf/100 ft ²	0.4788026	Pa
ψ_g	Geothermal gradient	°F/100 ft	1.8223	°C/100 m
ψ_{gw}	Geothermal gradient adjusted for water depth	°F/100 ft	1.8223	°C/100 m

^a Conversion Factor is a divider to convert data expressed in SI base or derived units into a value expressed in USC units. It is a multiplier to convert data expressed in USC units into a value expressed in SI base or derived values.

4 Fluid Flow Fundamentals and Rheological Models

4.1 Flow Fundamentals and Rheological Models

4.1.1 The behavior of a fluid depends on the flow regime, which in turn directly affects the ability of that fluid to perform its basic functions. Flow can be laminar or turbulent, depending on the fluid velocity, density, viscosity, and size and shape of the flow channel. Between laminar and turbulent flow, the fluid can pass through a transition region where movement of the fluid exhibits both laminar and turbulent characteristics. If the flow occurs in an annulus, as in a drilling situation, the rotation of the inner surface (the drill pipe) can create turbulent instabilities at any flow rate.

4.1.2 In axial laminar flow, the fluid moves parallel to the walls of the flow channel in smooth lines. Flow tends to be laminar when the fluid is moving slowly and/or when the fluid is viscous. In laminar flow, the pressure required to move the fluid increases with increasing velocity and viscosity.

4.1.3 In turbulent flow, the fluid is swirling and eddying as it moves along the flow channel, even though the bulk of the fluid moves forward. These velocity fluctuations can arise spontaneously. Wall roughness and rapid changes in flow direction can increase the amount of turbulence. Flow tends to be turbulent at higher velocities and/or when the fluid exhibits low viscosity. In turbulent flow, the pressure required to move the fluid increases linearly with density and approximately with the square of the velocity. This means more pump pressure is required to move a fluid in turbulent flow than in laminar flow.

4.1.4 The transition from axial laminar to turbulent flow is controlled by the relative contributions of viscous and inertial forces in the flow. Viscous forces dominate in laminar flow; inertial forces are more dominant in

turbulent flow. For Newtonian fluids, viscous forces vary linearly with the flow rate, while inertial forces vary as the square of the flow rate.

4.1.5 The ratio of inertial forces to viscous forces is the *Reynolds number*, N_{Re} :

$$N_{Re} = \frac{\rho V d}{\mu} \quad (1)$$

where (in consistent units)

ρ is the fluid density;

V is the average flow velocity;

d is the diameter of the flow channel;

μ is the fluid viscosity.

4.1.6 The transition from laminar to transitional flow occurs at the *critical velocity*. For typical drilling fluids, this normally occurs over a range of velocities corresponding to Reynolds numbers between 2000 and 4000 (see Section 7 for further details).

4.1.7 Secondary flows known as *Taylor vortices* can form in an annulus with a rotating drill string due to centrifugal and shear instabilities. This condition can substantially increase annular pressure loss. Additionally, turbulence-like motion may occur even in the absence of axial flow. For low flow rates, however, use of turbulent pressure loss models could under predict results even more than using laminar models.

4.2 Viscosity

4.2.1 *Viscosity* (μ) is defined as the ratio of shear stress to shear rate as shown in Equation (2). The traditional units of viscosity are dyne•s/cm², which is termed poise (symbol P). The SI unit of viscosity is the pascal-second (Pa•s). Since one P and one Pa•s represent a relatively high viscosity for most fluids, the derived units normally used are centipoise (cP) and millipascal-second (mPa•s), which are numerically equivalent (1 cP = 1 mPa•s).

$$\mu = \frac{\tau}{\dot{\gamma}} \quad (2)$$

where (in consistent units)

μ is the fluid viscosity;

τ is the shear stress;

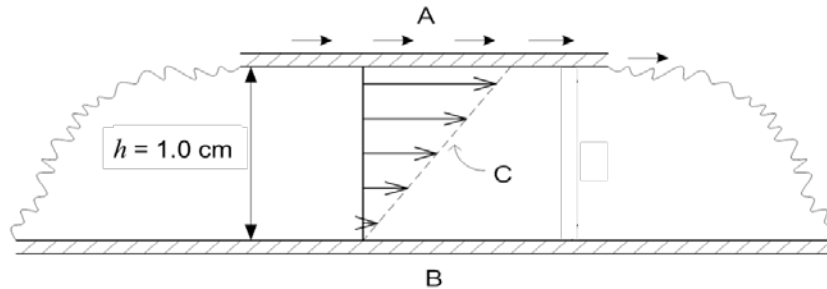
$\dot{\gamma}$ is the shear rate.

4.2.2 The viscosity of most drilling fluids varies with shear rate. Viscosity vs shear rate relationships can be determined and plotted from shear stress measurements made at several shear rates. Viscosity is also a function of the temperature and pressure of the fluid. The term *effective viscosity* is used to describe the viscosity either measured or calculated at the shear rate corresponding to existing flow conditions in the wellbore or drill pipe. This special term is used to differentiate the viscosity as discussed in this section from other viscosity terms.

4.2.3 To be meaningful, viscosity measurements should specify the shear rate, temperature, and pressure (if other than atmospheric).

4.3 Shear Stress

4.3.1 *Shear stress* is the force per unit area required to sustain fluid flow. In the parallel-plate example illustrated in Figure 1, a force of 10^{-5} N is applied to each cm^2 of the top plate A to keep it moving. Thus, the shear stress is 10^{-5} N/ cm^2 or 0.1 Pa. An opposing force is required on the bottom plate B to keep it stationary. The same shear stress of 0.1 Pa is found at any level in the fluid along the velocity profile C. The distance between the plates (h) is 1.0 cm.



Key

- A moving plate
- B stationary plate
- C velocity profile
- h distance between the plates (1 cm)

Figure 1—Parallel Plates with Fluid-filled Gap Showing Effects of Upper Plate Sliding Past Lower Plate

4.3.2 Shear stress, τ , is expressed mathematically as:

$$\tau = \frac{F}{A} \quad (3)$$

where (in consistent units)

τ is the shear stress;

F is the force;

A is the surface area subjected to stress.

4.3.3 In a horizontal pipe, the force, F , pushing a column of liquid through the pipe is expressed as the pressure on the end of the liquid column times the area of the end of the column:

$$F = P \frac{\pi d_i^2}{4} \quad (4)$$

where (in consistent units)

F is the applied force;

d_i is the internal diameter of the pipe;

P is the pressure on the end of the liquid column.

4.3.4 The area of the fluid surface, A , in contact with the pipe wall over the length is given by:

$$A = \pi d_i L \quad (5)$$

where (in consistent units)

A is the surface area of the fluid;

d_i is the internal diameter of the pipe;

L is the length of the pipe.

4.3.5 Thus, the shear stress at the pipe wall, τ_w , is expressed as:

$$\tau_w = \frac{F}{A} = \frac{d_i P}{4L} \quad (6)$$

4.3.6 In an annulus of known inner and outer diameters, the shear stress is expressed in the same manner:

$$F = \frac{P\pi d_h^2}{4} - \frac{P\pi d_p^2}{4} = \frac{\pi P}{4} (d_h^2 - d_p^2) \quad (7)$$

where (in consistent units)

d_p is the pipe outside diameter;

d_h is the hole diameter or casing inside diameter;

and

$$A = \pi d_h L + \pi d_p L = \pi L (d_h + d_p) \quad (8)$$

so that

$$\tau_w = \frac{F}{A} = \frac{\frac{\pi P}{4} (d_h - d_p) (d_h + d_p)}{\pi L (d_h + d_p)} \quad (9)$$

and

$$\tau_w = \frac{P(d_h - d_p)}{4L} \quad (10)$$

where (in consistent units)

τ_w is the shear stress at the wall;

P is the pressure on the end of the liquid column;

d_p is the pipe outside diameter;

d_h is the hole diameter or casing inside diameter;

L is the length of the pipe.

4.4 Shear Rate

4.4.1 *Shear rate* ($\dot{\gamma}$) is a velocity gradient measured across the diameter of a pipe or annulus. It is the rate at which one layer of fluid is sliding past another layer. As an example, consider the example illustrated in Figure 1. The fluid layer near the bottom plate B is motionless while the fluid layer near the top plate A is moving at almost 1 cm/s. Halfway between the plates, the fluid velocity is the average 0.5 cm/s.

4.4.2 The *velocity gradient* is the rate of change of velocity (ΔV) along the velocity profile. For the simple case shown in Figure 1, the shear rate is $\Delta V/h$ with units of 1/s or s^{-1} . The reciprocal second, also called the inverse second, is the standard unit for shear rate.

4.4.3 The example in Figure 1 applies to Newtonian fluids where the shear rate is constant throughout. Such is not the case for non-Newtonian fluids. In laminar flow inside a pipe, for example, the shear rate for non-Newtonian fluids is highest next to the pipe wall. An average shear rate may be used for some calculations, but the shear rate itself is not constant across the flow channel.

4.4.4 It is important to express the shear rate concept mathematically so that models and calculations can be developed. Shear rate ($\dot{\gamma}$) is defined as:

$$\dot{\gamma} = \frac{\Delta V}{\Delta h} \quad (11)$$

where (in consistent units)

$\dot{\gamma}$ is the shear rate;

ΔV is the flow velocity change between fluid layers;

Δh is the distance between fluid layers.

4.4.5 In a pipe, the shear rate at the pipe wall ($\dot{\gamma}_{wp}$) for a Newtonian fluid can be expressed as a function of the average velocity (V_p) and the pipe internal diameter (d_i).

$$\dot{\gamma}_{wp} = \frac{8V_p}{d_i} \quad (12)$$

in which

$$V_p = \frac{Q}{A} = \frac{4Q}{\pi d_i^2} \quad (13)$$

where (in consistent units)

$\dot{\gamma}_{wp}$ is the shear rate at the pipe wall for a Newtonian fluid;

Q is the volumetric flow rate;

A is the pipe internal surface area;

d_i is the pipe internal diameter;

V_p is the average velocity inside the pipe.

4.4.6 In a concentric annulus of outside diameter (d_h) and inside diameter (d_p), the wall shear rate for a Newtonian fluid can be shown to be:

$$\dot{\gamma}_{wa} = \frac{12V_a}{d_h - d_p} \quad (14)$$

in which

$$V_a = \frac{4Q}{\pi(d_h^2 - d_p^2)} \quad (15)$$

where (in consistent units)

$\dot{\gamma}_{wa}$ is the shear rate at the annulus wall for a Newtonian fluid;

Q is the volumetric flow rate;

d_p is the pipe outside diameter;

d_h is the hole diameter or casing inside diameter;

V_a is the average fluid velocity in annulus.

4.4.7 Relationships that correct the pipe and annular shear rates for non-Newtonian behavior are given in Sections 5 and 7.

4.5 Shear Stress/Shear Rate Relationship

4.5.1 In summary, the *shear stress* (τ) is the force per unit area required to sustain fluid flow. *Shear rate* ($\dot{\gamma}$) is the rate at which the fluid velocity changes with respect to the distance from the wall. *Viscosity* (μ) is the ratio of the shear stress to shear rate.

4.5.2 The mathematical relationship between shear rate and shear stress is the *rheological model* of the fluid. Numerous models have been developed to describe the flow behavior of fluids, virtually all based on empirical measurements. However, a select few are universally applied to drilling fluids. These are discussed later in this section.

4.6 Fluid Characterization

4.6.1 Fluids can be classified by their rheological behavior. Fluids whose viscosity remains constant with changing shear rate under otherwise constant conditions are known as *Newtonian* fluids. *Non-Newtonian* fluids are those fluids whose viscosity varies with changing shear rate.

4.6.2 Temperature and pressure affect the viscosity of a fluid. Therefore, the test temperature and pressure must be specified to properly describe the drilling fluid flow. The test protocol also is important.

4.6.3 Pertinent mathematical models used for hydraulic calculations are shown in later sections.

4.7 Newtonian Fluids

4.7.1 Fluids for which shear stress is directly proportional to shear rate are called Newtonian fluids. Water, glycerin, light oils, and brines are examples of Newtonian fluids.

4.7.2 A single viscosity measurement characterizes a Newtonian fluid at a given temperature and pressure.

4.8 Non-Newtonian Fluids

4.8.1 Fluids for which shear stress is not directly proportional to shear rate are called non-Newtonian. Most drilling fluids are non-Newtonian.

4.8.1.1 Drilling fluids are *shear thinning* when they exhibit less viscosity at higher shear rates than at lower shear rates.

4.8.1.2 Some non-Newtonian fluids exhibit *shear-thickening* behavior in laminar flow. The viscosity of these fluids increases with increasing shear rate. Shear-thickening behavior rarely occurs in drilling fluids circulated in a well.

4.8.2 The distinction between Newtonian and non-Newtonian fluids can be illustrated by using the API standard viscometer (rotational coaxial-cylinder, Couette-type viscometer) described in Section 5. If the 600 r/min dial reading (R_{600}) is twice the 300 r/min reading (R_{300}), the fluid exhibits Newtonian flow behavior. If R_{600} is less than twice R_{300} , the fluid is non-Newtonian and shear-thinning.

4.8.3 One type of shear-thinning fluid begins to flow as soon as a shear force or pressure, regardless of how slight, is applied. Such fluids are termed *pseudoplastics*. Increasing shear rate causes a progressive decrease in viscosity.

4.8.4 Another type of shear-thinning fluid does not flow until a given shear stress is applied. The shear stress required to initiate flow is called the *yield stress*. These fluids are known as *viscoplastics*.

4.8.5 Fluids also can exhibit time-dependent effects. Under constant shear rate, *thixotropic* fluids experience a decrease in viscosity while *rheopectic* fluids experience an increase in viscosity with time.

4.8.6 Thixotropic fluids can also exhibit a behavior known as *gelation* or *gel-strength development*. Time-dependent forces cause an increase in viscosity as the fluid remains static. Sufficient force must be exerted on the fluid to overcome the gel strength to initiate flow.

4.8.7 The range of drilling fluid rheological characteristics can vary from elastic, gelled solids at one extreme to purely viscous, Newtonian fluids at the other. These fluids can exhibit Newtonian, pseudoplastic, viscoplastic, or other behavior under specific conditions. It is not unreasonable to assume that all drilling fluids are *viscoelastic*, meaning that they exhibit both viscous and elastic properties to varying degrees. However, the linear-elastic response of drilling fluids is rarely tested and the topic is beyond the scope of this document.

4.8.8 For practical reasons in the field and in most drilling fluid laboratories, flow properties usually are expressed in simple rheological terms. General statements regarding drilling fluids are subject to exceptions because of their extraordinary complexity.

4.9 Rheological Models

4.9.1 General

Rheological models provide assistance for characterizing fluid flow. Knowledge of rheological models combined with practical experience is necessary to fully understand fluid performance. No single model available at this time completely describes rheological characteristics of drilling fluids over their entire shear rate range.

Rheological models used for drilling fluids describe only time-independent, purely viscous behavior. A *rheogram*, the plot of shear stress vs shear rate, is used to graphically depict a rheological model. Figure 2 illustrates rheograms plotted on rectangular coordinates for three rheological models discussed later in this section. The curves are plotted using viscometer data (dial reading vs rotational speed) measured on a standard 6-speed viscometer.

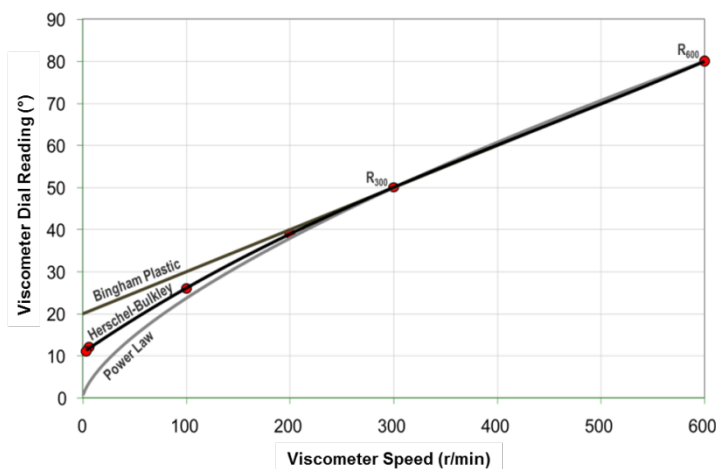


Figure 2—Rheograms of Three Rheological Models on Rectangular Coordinates

4.9.2 Bingham Plastic Model

This model describes fluids for which the shear stress/shear rate ratio is linear once a specific shear stress has been exceeded. Two parameters, *plastic viscosity* (PV) and *yield point* (YP), are used to describe this model. Because these parameters are determined at shear rates of 511 s^{-1} and 1022 s^{-1} [300 and 600 r/min, respectively, on a standard viscometer (R1B1 rotor/bob combination, F1.0 spring)], this model characterizes fluids in the higher shear rate range where the shear rate/shear stress relationship is linear. The higher shear rates also ensure that the fluid in the gap of the concentric-cylinder viscometer is fully sheared. A rheogram of the Bingham plastic model on rectangular coordinates is a straight line that intersects the zero shear rate axis at a shear stress greater than zero (yield point).

4.9.3 Ostwald–de Waele Model

This model, universally known as the power law, is used to describe the flow of shear-thinning or pseudoplastic drilling fluids. This model describes fluids for which the rheogram is a straight line when plotted on a log-log graph. Such a line has no intercept, so a true power law fluid does not exhibit a yield stress. The two required power law constants, flow behavior index (n_p) and power law consistency factor (k_p), from this model should be determined from data taken at viscometer shear rates of 1022 s^{-1} and 511 s^{-1} [300 and 600 r/min, respectively, on a standard viscometer (R1B1 rotor/bob combination, F1.0 spring)].

4.9.4 Herschel–Bulkley (H-B) Model

Also called the *modified power law*, *yield-power law*, and *yield-pseudoplastic model*, the H-B model is used to describe the flow of pseudoplastic drilling fluids that exhibit a yield stress (τ_y) that must be exceeded to initiate flow. A rheogram of shear stress minus yield stress vs shear rate is a straight line on log-log coordinates. This model is widely used because it

- a) describes the flow behavior of most drilling fluids,
- b) includes a yield stress value important for hydraulics issues, and
- c) includes the Bingham plastic model and power law as special cases.

4.9.5 Rheological parameters recorded in an API Drilling Fluid Report include PV and YP from the Bingham plastic model. These two terms can be used to calculate power law model key parameters: flow behavior index (n_p) and consistency factor (k_p); for the H-B model, an additional yield-stress term (τ_y) is required with the H-B flow-behavior index (n) and the consistency factor (k). Gel strengths (G_{10s} and G_{10m}) measured after the fluid

has been left static for 10 s and 10 min, respectively, also are reported on the API Drilling Fluid Report. The 30-min gel strength (G_{30m}) sometimes is also measured and reported when warranted.

4.9.6 Mathematical treatments of H-B, Bingham plastic, and power law fluids are described in Section 5.

4.9.7 Flow characteristics of a drilling fluid are controlled by the viscosity of the base fluid (the continuous phase); any solid particles, emulsified droplets of oil or water/brine, or gases within the fluid (the discontinuous phase); the flow channel characteristics; and the volumetric flow rate. Any interactions among the continuous and discontinuous phases, either chemical or physical, have a marked effect on the rheological parameters of a drilling fluid. The parameters calculated by use of Bingham plastic and other models are indicators commonly used to guide fluid conditioning to obtain the desired performance.

5 Rheological Parameters

5.1 Measurement of Rheological Parameters

5.1.1 General

Determination of drilling fluid rheological parameters is important in the calculation of hydraulics, hole-cleaning efficiency, and prediction of weight-material sag in oil wells.

5.1.2 Orifice-viscometer Marsh Funnel

5.1.2.1 The Marsh funnel is widely used as a measuring instrument in the field. The measurement, referred to as the funnel viscosity, is a timed rate of flow usually recorded in seconds per quart (946 ml). It consists of a conical funnel that holds 1.5 L of drilling fluid with a short tube at the bottom of the cone. The instrument is designed so that by following standard procedures the outflow time of one quart of fresh water at $70\text{ }^{\circ}\text{F} \pm 5\text{ }^{\circ}\text{F}$ ($21\text{ }^{\circ}\text{C} \pm 3\text{ }^{\circ}\text{C}$) is $26\text{ s} \pm 0.5\text{ s}$ with a graduated cup as a receiver. The Marsh funnel is a standard test method for clay construction slurries.

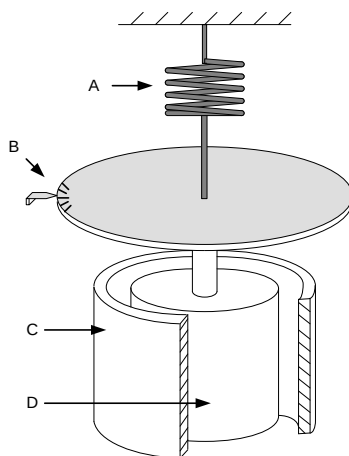
5.1.2.2 Funnel viscosity is a rapid, simple test that is made routinely on all liquid drilling fluid systems. It is most useful to alert personnel to changes in the drilling fluid properties or conditions. When a change in funnel viscosity is observed, rheological testing using a concentric-cylinder viscometer can help identify the change in fluid properties. Funnel viscosity, however, is a one-point measurement and therefore does not give any information as to why the actual fluid viscosity may be high or low. No single funnel viscosity measurement can be taken to represent a consistent value for all drilling fluids of the same type or of the same density.

5.1.2.3 The procedure for measuring funnel viscosity shall be followed as outlined in API 13B-1 and API 13B-2.

5.1.3 Rotational Coaxial-cylinder Viscometer

5.1.3.1 Rotational coaxial-cylinder viscometers (also called Couette-type viscosimeter) are the most commonly used viscometers for measuring the rheological properties of drilling fluids. The test fluid is contained in the annular space between two coaxial cylinders. In Couette-type viscometers, the outer rotor (sleeve) is driven at a constant rotational speed, thereby applying a torque on the inner cylinder (bob).

5.1.3.2 The resulting torque on the inner cylinder for mechanical Couette viscometers is measured with a torsion spring that restrains the movement. A dial attached to the bob indicates deflection of the bob in degrees that is proportional to the shear stress. This mechanism is illustrated in Figure 3. Digital viscometers use the same geometry and principle; however, a torque sensor may be used to indicate the shear stress.



Key

- A torsion spring
- B dial
- C rotor (sleeve)
- D bob

Figure 3—Couette-type, Mechanical Rotational Viscometer with Dial Readout

5.1.3.3 Instrument constants are such that PV and YP are directly obtained by readings from rotor speeds of 600 r/min (R_{600}) and 300 r/min (R_{300}) using a standard rotor and bob geometry (known as R1B1) and a standard spring (F1.0). With a rotor inner diameter fixed at 1.450 in. (3.683 cm) and a bob diameter fixed at 1.358 in. (3.449 cm) for R1B1, the diameter ratio (rotor/bob) is maintained at 1.0678, a value that meets international German Institute for Standardization (DIN) standards. Also, the dial reading at 300 r/min (R_{300}) is equal to the fluid viscosity at a shear rate of 511 s^{-1} , aptly identifying viscometers of this configuration as “direct-reading” instruments.

NOTE A rotor/bob diameter ratio < 1.1 ensures a nominally uniform shear stress across the gap and to keep fluid homogeneous.

5.1.3.4 Table 3 lists the types and operating limits of viscometers commonly used to test drilling fluids. Tier 1 units are portable devices used in the field and drilling fluids laboratories. Most are mechanical units like those illustrated in Figure 3, while others are digital. Tier 2-4 viscometers are computer-controlled units designed for laboratory use and only used in the field under special circumstances. All of the viscometers listed in Table 3 use the same principle; however, they differ in drive system, shear rate range, and method of readout.

Table 3—Types of Viscometers for Measuring Drilling Fluid Rheological Properties

Tier	Type	Maximum Pressure	Maximum Temperature
1	Portable (field)	Atmospheric	200 °F (93 °C)
2	High temperature	1000–2500 lbf/in. ² (6900–17,200 kPa)	500 °F (260 °C)
3	High temperature/high pressure	20,000 lbf/in. ² (137,900 kPa)	≥500 °F (≥260 °C)
4	Ultra-high temperature/high pressure	≥30,000 lbf/in. ² (206,800 kPa)	≥500 °F (≥260 °C)

5.1.3.5 Operating procedures for field concentric-cylinder viscometers presented in API 13B-1 and API 13B-2 shall be followed. Specific operating procedures for those instruments not included in these two documents can be obtained from the respective manufacturers.

5.2 Rheological Models

5.2.1 Principle

The determination of drilling fluid rheological parameters is important for formulating, monitoring, and treating drilling fluids and in the calculation of hydraulics, hole-cleaning efficiency, and mitigation of weight-material sag in oil wells. Additional details are provided hereafter for the three rheological models presented in 4.9—Bingham plastic, power law, and H-B. The H-B model has become the de facto model for engineering calculations in the drilling industry and is recommended for field and office use. This model consistently provides good simulation of measured rheological data for both water-based and non-aqueous drilling fluids.

It is important to note that the constitutive equations provided in this section cannot be used directly to calculate friction pressure losses. They first must be converted to their respective flow equations^[4,5,9] (Section 7).

5.2.2 Instrumentation Configuration

Use of a rotational coaxial-cylinder viscometer is assumed in this Section 5. The temperature at which the measurements are taken is important and should be considered when using the derived rheological parameters. Recommended test temperature guidelines are given in API 13B-1 (water-based drilling fluids) and API 13B-2 (oil- and synthetic-based drilling fluids).

Drilling fluid rheological properties are universally measured using standard oilfield viscometers requiring application of instrument conversion factors.^[6] The following apply to R1B1 viscometer geometry and F1.0 spring.

- Shear stress (τ) expressed in lbf/100 ft² is determined by multiplying the dial reading expressed in degrees, by 1.067.
- Shear rate ($\dot{\gamma}$) expressed in s⁻¹ is determined by multiplying the rotor speed expressed in r/min by 1.703.

5.2.3 Bingham Plastic Model

The Bingham plastic model shown in Equation (16) requires the two parameters PV and YP . These parameters are calculated using viscometer measurements R_{600} and R_{300} , as shown in Equations (17) and (18).

$$\tau = YP + \frac{PV}{511} \dot{\gamma} \quad (16)$$

where

$$PV = R_{600} - R_{300} \quad (17)$$

and

$$YP = R_{300} - PV \quad (18)$$

The Bingham plastic model provides a reasonable fit to the rheological behavior of a certain group of drilling fluid types, including water-based drilling fluids viscosified with bentonite. PV and YP values derived from this model are critical to the design, monitoring, and treatment of all drilling fluids, even if the Bingham model itself may not be the optimum choice to calculate pressure losses and evaluate other hydraulics issues.

PV represents the slope of a straight line between dial readings R_{600} ($\dot{\gamma} = 1022 \text{ s}^{-1}$) and R_{300} ($\dot{\gamma} = 511 \text{ s}^{-1}$), on rectilinear coordinates (dial reading vs $\dot{\gamma}$); YP is the intersection of this line with the vertical axis ($\dot{\gamma} = 0$). The viscometer data and derived parameters are temperature and pressure dependent, so care must be taken to associate results with measurement conditions.

PV and YP in Equations (17) and (18) are in viscometer units ($^{\circ}/\text{s}^{-1}$ and $^{\circ}$, respectively) rather than the customary units given in Table 2. This ensures that the parameters are typically integer values in USC units. The discrepancies of about 6 % are resolved later when the two parameters are used for pressure-loss calculations.

5.2.4 Power Law Model

The power law model shown in Equation (19) requires two parameters: high shear rate flow behavior index (n_p) and consistency factor (k_p). These parameters are calculated using viscometer measurements R_{600} and R_{300} , as shown in Equations (20) and (21).

$$\tau = k_p \dot{\gamma}^{n_p} \quad (19)$$

where

$$n_p = 3.32 \log_{10} \left(\frac{R_{600}}{R_{300}} \right) = 3.32 \log_{10} \left(\frac{2PV + YP}{PV + YP} \right) \quad (20)$$

and

$$k_p = \frac{R_{300}}{511^{n_p}} = \frac{PV + YP}{511^{n_p}} \quad (21)$$

The power law provides a reasonable fit for a certain range of drilling fluid types, such as polymer water-based drilling fluids. It is challenging, however, to use n_p and k_p to monitor and treat most drilling fluids. The flow behavior index (n_p), which varies from about 0.3 to 1.0 for drilling fluids, can help characterize rheological behavior. Lower n_p values suggest higher levels of shear thinning; $n_p = 1$ for Newtonian behavior.

A rheogram plot of dial reading vs shear rate is a straight line on log-log coordinates that passes through points measured at 600 r/min and 300 r/min. The slope of this line is n_p , and k_p is the intercept at $\dot{\gamma} = 1 \text{ s}^{-1}$.

5.2.5 H-B Rheological Model

5.2.5.1 General

The constitutive equation of the H-B model shown in Equation (22) requires three parameters: n (flow behavior index), k (consistency factor), and τ_y (yield stress).^[7,9] These parameters are calculated as shown in Equations (23) and (24) from viscometer measurements R_{600} and R_{300} and an approximation measurement (see 5.2.5.2) or a numerical prediction of τ_y (see 5.2.5.3).

$$\tau = \tau_y + k\dot{\gamma}^n \quad (22)$$

where

$$n = 3.32 \log_{10} \left(\frac{R_{600} - \tau_y}{R_{300} - \tau_y} \right) = 3.32 \log_{10} \left(\frac{2PV + YP - \tau_y}{PV + YP - \tau_y} \right) \quad (23)$$

and

$$k = \frac{(R_{300} - \tau_y)}{511^n} = \frac{(PV + YP - \tau_y)}{511^n} \quad (24)$$

This rheological model regularly provides a very good fit for nearly all water-, oil-, and synthetic-based drilling fluids. Furthermore, the constitutive equation includes as special cases the Bingham plastic model and power law described in 5.2.3 and 5.2.4, respectively. When the $\tau_y = YP$, the H-B equation reduces to the Bingham plastic model where $k = PV/511 = 0.001957PV$. When a drilling fluid does not exhibit a yield stress ($\tau_y = 0$), the model reduces to the power law. The value for τ_y varies between zero and YP (inclusive).

5.2.5.2 Measurement Methods for Drilling Fluid H-B Parameters

H-B parameters can be determined from conventional 6-speed oilfield rotational concentric cylinder viscometers without any computer processing. However, these viscometers are not designed for measuring τ_y directly. In fact, measurement of τ_y is challenging even when using sophisticated viscometers.

A commonly used approximation for τ_y known as the low shear rate yield point (LSYP) is calculated from viscometer readings R_6 and R_3 as shown in Equation (25):

$$\tau_y \approx LSYP = 2R_3 - R_6 \quad (25)$$

Yield stress τ_y can be approximated by measurement on oilfield digital viscometers that operate at shear rates as low as 0.017 s^{-1} . Special-purpose viscometers that directly measure τ_y also are available but are not in wide use at this time.

5.2.5.3 Numerical Solution Methods for Drilling Fluid H-B Parameters

Numerical techniques using unweighted or weighted parameters also can be used to determine H-B parameters. Spreadsheets or computer programs are required for this purpose. The weighted-parameter least-squares method^[10] is inherently superior, but is more complex to solve. However, the weighted-parameter method more consistently preserves the original values for R_{600} and R_{300} .

Another numerical solution involves selection of a third data value in addition to R_{600} and R_{300} and using a simple convergence approach to determine τ_y . Possible choices include either R_6 or R_3 . Values for τ_y are sequentially tested until the calculated and measured values for the chosen parameter converge. Original

values for R_{600} and R_{300} are preserved by definition. H-B parameters n and k can then be calculated directly using Equations (23) and (24), respectively.

6 Prediction of Downhole Behavior of Drilling Fluids

6.1 Principle

The downhole behavior of fluid properties should be taken into account to accurately calculate the hydraulics of oil-well drilling fluids. This is especially important when oil- and synthetic-based drilling fluids are used. The downhole behavior of drilling fluids is dependent on static and dynamic temperatures, pressures, rheological properties, and density. Each of these areas is discussed in this Section 6.

6.2 Temperature Predictions of Circulating Drilling Fluids

6.2.1 The prediction of bottomhole circulating temperature (T_{bhc}) is necessary for use in hydraulic and drilling fluid density modeling, especially when invert emulsion and all-oil drilling fluids are used. The prediction of circulating temperatures in a wellbore is a very complex task, however, as many operational and physical parameters are required. A simplified calculation procedure is presented here that requires a minimum of input parameters and is generally sufficiently accurate to predict circulating temperatures. This model^[11,12], which can be easily programmed in a spreadsheet program, gives acceptable results within the following ranges for the bottomhole static temperature (T_{bhs}) and geothermal gradient (ψ_g):

- bottomhole static temperature: 166 °F to 414 °F;
- geothermal gradient: 0.83 °F/100 ft to 2.44 °F/100 ft.

6.2.2 Input parameters needed for the prediction of downhole circulating temperatures:

- a) true vertical depth (D_{tvd});
- a) bottomhole static temperature (T_{bhs});
- b) for offshore wells, water depth (D_w); for land wells, $D_w = 0$;
- c) geothermal gradient (ψ_g);
- d) geothermal gradient adjusted for water depth (ψ_{gw});
- e) surface temperature (T_0) measured at 50-ft depth or approximated by the annual mean surface temperature.

6.2.3 Temperature calculation methods for land and offshore wells are as follows.

- a) For land wells with a known bottomhole static temperature (T_{bhs}), the bottomhole circulating temperature (T_{bhc}) can be calculated using the following method.^[11]

- 1) Calculate geothermal gradient ψ_g expressed in °F/100 ft:

$$\psi_g = 100 \frac{(T_{bhs} - T_0)}{D_{tvd}} \quad (26)$$

- 2) Estimate T_{bhc} expressed in °F:

$$T_{bhc} = -1021 + \left(3354 \frac{\psi_g}{100} \right) + \left(1.342 - 22.28 \frac{\psi_g}{100} \right) T_{bhs} \quad (27)$$