Baker Hughes INTEQ

FLUID Facts

Engineering Handbook

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INTEQ

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Chapter **1**

Products, Applications, and Testing

Cross Reference Chart

The following cross reference chart is a compilation of the Baker Hughes INTEQ trade name drilling fluid products. The products are organized alphabetically. The product name is followed by a brief description of its function (application) and a listing of competitive products that are either chemically similar or designed to perform a comparable function.

When "chemical" matches could not be made or were not known, the competitive product with the closest functional performance is listed. If no competitive product is listed, there is no known equivalent.

While every effort has been made to ensure the accuracy of the chart, no guarantee of the performance of competing products can be given. If a competitive product must be used in an INTEQ fluid system, its performance and effect on the system should be checked by pilot testing.

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
6-UP™	Rheology modifier for oil and synthetic-base fluids	RM-63	INTERDRILL LO-RM	VERSAMOD / NOVAMOD
ALL-TEMP™	Water-base deflocculent and rheology stabilizer with special application in high temperature environments	THERMA-THIN	IDSPERSE XT	RESINEX / THERMEX
ALPLEX™	Aluminum complex used to control gumbo and water-sensitive shales			
AMI-TEC™	Amine-base corrosion inhibitor	BARA FILM	IDFILM 220X IDFILM 820X	CONQOR 101, 202 and 303A
AMPLI-FOAM™	Foaming agent for mist and stiff foam drilling	BARAFOAM / DRILFOAM	HI FOAM 440	MI FOAMER / FOAMER 80
AQUA-COL™	Cloud point glycol for borehole stability, ROP enhancement, lubricity and HT/HP reduction in *fresh water* and *low-salinity* brines	GEM CP	STAPLEX 500 STAPLEX 650	GLYDRIL 101
AQUA-COL™ B	Cloud point glycol for borehole stability, ROP enhancement, lubricity and HT/HP reduction in *medium-salinity* brines			
AQUA-COL™ D	Cloud point glycol for borehole stability, ROP enhancement, lubricity and HT/HP reduction in *high-salinity* brines	GEM GP	STAPLEX 500	GLYDRIL 208
AQUA-COL™ S	Cloud point glycol for borehole stability, ROP enhancement, lubricity and HT/HP reduction in *saturated* salt brines	GEM SP		GLYDRIL 208
AQUA-COL™ XS	*High-temperature* cloud point glycol for borehole stability, ROP enhancement, lubricity and HT/HP reduction in saturated salt brines			
AQUA-DRILL^{SM}	Drilling fluid system using glycol technology		QUADRILL	GLYDRIL 2000

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
AQUA-MAGIC™	Differential sticking preventative			LUBE-167
AQUA-SEAL™	Fluid loss and shale control polymer for carbonate systems			
BIO-DRILL®	Insoluble glycol, bit balling preventative			
BIO-GREEN®	Biodegradable ester base fluid for BIO-GREEN system	PETROFREE		FINAGREEN
BIO-LOSE™	Modified polysaccharide, filtration control agent	FILTER CHECK	IDFLO	FILTRON
BIO-PAQ™	Derivatized poly-saccharide, filtration control agent for NaCl, $CaCl_2$, KCl, $CaBr_2$ brines			
BIO-SPOT®	Non-hydrocarbon, low-toxicity spotting fluid	DUAL PHASE / BARO SPOT		PIPE-LAX ENV
BIO-SPOT II	Non-hydrocarbon, low-toxicity spotting fluid concentrate			
BLACK-MAGIC®	Oil-base spotting fluid	EZ SPOT	IDFREE / IDFREE UW	PIPE-LAX / ORO-NEGRO
BLACK-MAGIC® CLEAN	Environmentally safe spotting fluid	ENVIRO-SPOT	IDFREE NT	PIPE-LAX ENV
BLACK-MAGIC® LT	Low-toxicity, oil-base spotting fluid	EZ SPOT	IDFREE / IDFREE UW	
BLACK-MAGIC® SFT	Oil-base spotting fluid concentrate			PIPE-LAX
BRINE-PAC™	Corrosion inhibitor for solids free fluids	BARACOR 100	IDFILM 820X	CONQOR 303A
CARBO-DRILL^{SM}	Mineral and diesel oil base, invert emulsion drilling fluid system	INVERMUL / ENVIROMUL	INTERDRILL D INTERDRILL NT	VERSADRILL / VERSACLEAN
CARBO-GEL®	Organophilic hectorite, oil-base fluid viscosifier	BENTONE 38	TRUVIS HT	
CARBO-GEL® II	Economical organophilic hectorite, oil-base fluid viscosifier	GELTONE I	INTERDRILL VISTONE	VG-69/VG PLUS

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
CARBO-MIX™	Emulsifier for low OWR CARBO-DRILL systems	INVERMUL / INVERMUL NT		VERSAMUL
CARBO-MUL®	Emulsifier and wetting agent for CARBO-DRILL systems	EZ MUL / EZ MUL NT	INTERDRILL OW	VESACOAT
CARBO-MUL® HT	High-temperature emulsifier and wetting agent for CARBO-DRILL systems	EZ MUL EZ MUL NT	INTERDRILL EMUL HT	VERSAMUL
CARBO-SEAL™	Modified hydrocarbon LCM for oil-, water-, and synthetic-base fluid systems	STEEL-SEAL		
CARBO-TEC®	High-temperature emulsifier and wetting agent for CARBO-DRILL systems	EZ MUL / EZ MUL NT	INTERDRILL EMUL	VERSAMUL
CARBO-TEC® HW	Emulsifier for low OWR CARBO-DRILL systems	INVERMUL / INVERMUL NT	INTERDRILL OW	VERSAMUL
CARBO-TROL®	Asphaltic filtration control agent for CARBO-DRILL systems	AK-70	TRUDRILL S INTERDRILL S	
CARBO-TROL® A9	Organophilic lignite filtration control agent for CARBO-DRILL systems	DURATONE HT	INTERDRILL NA	VERSALIG
CARBO-TROL® HT	High softening point gilsonite, filtration control agent for CARBO-DRILL systems	BARABLOK 400	TRUDRILL S	VERSATROL I
CARBO-VIS™	Organophilic bentonite, oil-base fluid viscosifier	GELTONE I	INTERDRILL VISTONE	VG-69/VG-PLUS VERSAGEL
CHEK-LOSS®	Seepage loss control and differential pressure sticking preventative	BAROFIBRE		M-I-X II

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
CHEK-LOSS® Coarse	Seepage loss control and differential pressure sticking preventative for fractured zones and porous sands	BAROFIBRE COARSE		M-I-X II COARSE
CHEMTROL® X	High-temperature filtration control agent for water-base fluids	BARANEX	CALO-TEMP	DURASTAR / RESINEX
CHROME-FREE II	No chrome added lignosulfonate	ENVIRO-THIN	Chrome-Free Lignosulfonate	SPERSENE CF
CLEAR-DRILL™ K	Potassium formate used in the continuous phase of the CLEAR-DRILL K system		IDSALT FK	
CLEAR-DRILL™ N	Sodium formate used in the continuous phase of the CLEAR-DRILL N system		IDSALT FS	FLO-PRO SF
CMC HV	High-viscosity, technical grade sodium carboxymethyl cellulose for filtration control and supplemental viscosity.	CELLEX (High Vis)	CMC High Vis Tech	CMC HV
CMC LV	Low-viscosity, technical grade sodium carboxymethyl cellulose for filtration control	CELLEX	CMC Low Vis Tech	CMC LV
DENSIMIX®	API specification hematite	BARODENSE	Hematite	FER-OX
DRYOCIDE™	Thiocarbonate-base biocide		IDCIDE-L	
FILTREX®	Polyanionic lignin resin	BARANEX	HI-TEMP II	RESINEX
ISO-TEQ™	Olefin isomer, synthetic-base fluid for SYN-TEQ systems	PETROFREE LE	ULTIDRILL	NOVA-PLUS
KAT-DRILL™	Low charge, high molecular weight, cationic polymer	BARACAT		MCAT A
KEM-SEAL™	Co-polymer for high temperature filtration control	THERMA-CHEK	CALO-FLOW 100 / POLYTEMP	DURALON / DURASTAR
LD-8®	Non-hydrocarbon base defoamer for water-base fluids	BARA DEFOAM	DEFOAMER	DEFOAM L

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
LD-9™	Polyether, polyol defoamer for fresh and saltwater fluids	BARA DEFOAM HP	ANTIFOAM A	DEFOAM X
LIGCO®	Ground leonardite	CARBONOX	LIGNITE	TANNATHIN
LIGCON®	Causticized, ground leonardite	CC-16	Causticized Lignite	CAUSTILIG
LUBRI-FILM®	Extreme pressure, dry lubricant for water-base fluids	EP MUDLUBE	IDLUBE XL	EP LUBE
MAGNE-SET®	Acid soluble cement			
MD	Biodegradable drilling fluid detergent	CONDET	Drilling Detergent	DD
MIL-BAR®	API specification barite	BAROID	Barite	M-I BAR
MIL-BEN®	API specification, OCMA grade bentonite	SHUR-GEL	OCMA Bentonite	
MIL-CARB™	Ground and sized calcium carbonate	BARA CARB	IDCARB Custom	
MIL-CEDAR FIBER™	Shredded cedar fiber	PLUG-GIT	WOOD FIBER	MI CEDAR FIBER
MIL-CLEAN®	Water soluble, biodegradable detergent and rig wash	BARAKLEAN	IDWASH	KLEENUP
MIL-FIBER®	Shredded cane fiber	HY-SEAL	MUD FIBER	M-I FIBER
MIL-FREE®	Vegetable-oil base spotting fluid	ENVIROSPOT	IDFREE	PIPE-LAX
MIL-GARD®	Basic zinc carbonate sulfide scavenger	NO-SULF / BARACOR 44	Zinc Carbonate	SULF-X II
MIL-GARD® R	Water soluble, chelated zinc, sulfide scavenger		IDZAC	SV-120
MIL-KEM™	Lignosulfonate-base thinner for calcium-base fluids	LIGNOX	POLYLIG	RD 2000
MIL-LUBE™	Vegetable-oil base boundary layer and extreme pressure lubricant	TORQ-TRIM II	IDLUBE	LUBE-106

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
MIL-PAC™	Polyanionic cellulose	PAC-R	IDF-FLR	POLYPAC / PAC PLUS
MIL-PAC™ LV	Low viscosity, polyanionic cellulose	PAC-L	IDF-FLR XL	POLYPAC UL / PAC PLUS UL
MIL-PLUG®	Ground and sized nut shells	WALL-NUT	ID PLUG	NUT PLUG
MIL-SEAL™	Blended and sized LCM	BARO-SEAL	IDSEAL	KWIK SEAL
MIL-SPOT™ 2	Invert emulsion, weighted spotting fluid concentrate	EASY SPOT / ENVIROSPOT	IDFREE	PIPE-LAX W
MIL-TEMP®	Sulfonated styrene, maleic anhydride, high temperature rheology stabilizer		IDSPERSE XT	DURALON / RHEOSTAR
MIL-THIN™	Anionic, copolymer-base thinner	THERMA-THIN / THERMA-THIN DP	IDTHIN 500	TACKLE
MILFLAKE®	Shredded cellophane	JELFLAKE		FLAKE
MILGEL®	API specification Wyoming bentonite	AQUA-GEL	API Bentonite	M-I GEL
MILGEL® NT	API specification, untreated Wyoming bentonite	AQUA-GEL GOLD SEAL	Wyoming Bentonite	GEL SUPREME
MILMICA®	Sized muscovite mica	MICATEX	IDMICA	MICA
MILSTARCH®	Pregelatinized corn starch	IMPERMEX	IDFLO LT	My-Lo-Jel
MUD-PAC™	Corrosion inhibitor for solids-laden packer fluids	COAT-44 COAT-45	IDFILM 820X	CONQOR 303A
NEW-DRILL®	Liquid, high molecular weight, PHPA polymer	EZ MUD	IDBOND	POLY-PLUS

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
NEW-DRILL® HP	Enhanced performance, PHPA polymer		IDBOND P100	POLY-PLUS RD
NEW-DRILL® PLUS	Powdered, high molecular weight, PHPA	EZ MUD DP	IDBOND P / IDBOND PRD	POLY-PLUS DRY
NEW-TROL™	Polyacrylate-base filtration control agent	POLYAC	AP-21	SP-101
NEW-VIS™	Polymer blend for viscosity and gel strength		Rheopol Viscosifier	
NF-2®	Gas hydrate inhibitor			
NOXYGEN™	Liquid, oxygen scavenger	BARASCAV-L	IDSCAV 110	OS-1
OILFOS®	Sodium polyphosphate	BARAFOS	STP	PHOS
OMNI-COTE™	Wetting agent for oil- and synthetic-base fluids	DRILTREAT	INTERDRILL OW / ULTIDRILL OW	NOVAWET
OMNI-MIX™	Supplemental anionic emulsifier for oil- and synthetic-base fluids		ULTIDRILL FL	
OMNI-MUL™	Non-ionic emulsifier and wetting agent for oil- and synthetic-base fluids	LE SUPERMUL / EZ MUL NT	INTERDRILL EMUL HT / ULTIDRILL	NOVAMUL / VERSAMUL
OMNI-PLEX™	Synthetic polymer viscosifying agent for oil- and synthetic-base fluids	X-VIS	TRUPLEX	VERSA HRP
OMNI-TEC™	Anionic emulsifier for oil- and synthetic-base fluids	LE MUL / INVERMUL NT	ULTIDRILL EMUL	VERSACOAT
OMNI-TROL™	Temperature-stable, organophilic lignite, filtration control agent for oil- and synthetic-base fluids	DURATONE HT	INTERDRILL NA	VERSALIG

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
PARA-TEQ™	Non-toxic linear paraffin for SYN-TEQ fluid system	XP-07		VERSA PLUS
PENETREX®	Environmentally safe ROP enhancer and lubricant			TURBO DRIL-LUBE 100
PERF*FLOW*® 100	Bridging, viscosifying, and filtration control agent for use in PERF*FLOW* system under low-temperature conditions where acidization is required			
PERF*FLOW*® DIF	Bridging, viscosifying, and filtration control agent for use in PERF*FLOW* system		N-DRIL SYSTEM	FLO-PRO
PERMA-LOSE® HT	Nonfermenting, polymerized starch	DEXTRID	IDFLO HTR	POLY-SAL
POLY-KAT™	High charge, high molecular weight, cationic polymer	BARACAT		M-CAT
PROTECTOMAGIC®	Oil soluble, air blown asphalt	AK-70	IDTEX	
PROTECTOMAGIC® M	Water dispersible, air blown asphalt	AK-70	IDTEX W	STABIL HOLE
PYRO-TROL®	Acrylamide - AMPS copolymer for high temperature filtration control	THERMA-CHEK	CALO FLOW 100 POLYTEMP	DURALON
PYRO-VIS®	Supplemental viscosifier for saltwater PYRO-DRILL fluids	HP007	HP007	HP007
SALT WATER GEL®	API specification, attapulgite clay	ZEOGEL	Salt Gel	SALT GEL
SCALE-BAN™	Phosphate-base scale inhibitor	SURFLO H-35 BARACOR 120	IDPLEX 100	SI-1000
SHALE-BOND®	Water dispersible gilsonite	BARA-TROL / SHALE-BAN	Gilsonite	HOLECOAT / ASPHASOL

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
SOLUFLAKE®	Flake calcium carbonate used to control loss of circulation			
SUPER-COL®	High-yield bentonite	QUICK-GEL		KWIK-THIK
TEQ-THIN™ CF	Chrome-free modified tannin	ENVIRO-THIN		SPERSENE CF
UNI-CAL®	Chrome modified lignosulfonate	Q-BROXIN	Ferrochrome Lignosulphonate	SPERSENE
W-306 Dispersion	Polymeric viscosifier and fluid loss control agent for PERF*FLOW* systems			
W.O.™ 21 L	HEC suspension for workover fluids	LIQUI-VIS EP / LIQUI-VIS NT / BARAVIS	IDHEC L	VIS-L
W.O.™ 30 Fine Medium Coarse	Ground, sized calcium carbonate	BARACARB	Calcium Carbonate / IDCARB	SAFE-CARB
W.O.™ Defoam	Alcohol-base defoamer for all water-base fluids	BARA BRINE DEFOAM HP	DEFOAMER	DEFOAM X
X-CIDE® 102	Liquid, aldehyde biocide for drilling, workover, completion, and packer fluids			
X-CIDE® 207	Isothiazolin-base, powdered biocide		IDCIDE P	BACBAN III

Baker Hughes INTEQ		Comparable Competitive Products		
Product	**Description**	**Baroid**	**Dowell**	**MI**
X-LINK™	Cross-linking polymer composition with additional bridging agents used in water- and oil-base fluids			
XANPLEX®	Xanthan gum biopolymer	XC POLYMER	IDVIS	XC POLYMER
XANPLEX D	Dispersible xanthan gum biopolymer	BARAZAN D PLUS	IDVIS-D	FLO-VIS / DUO-VIS

Drilling Fluid Testing Procedures

Water-Base Fluids

Density (Fluid Weight) Measurement

Apparatus

Any instrument of sufficient accuracy to permit measurement within ± 0.1 lb_m/gal or ± 0.5, lb_m/ft^3 (± 0.01 g/cm^3) may be used.

Calibration

The instrument should be calibrated frequently with freshwater. Freshwater should give a reading of 8.3 lb_m/gal or 62.3 lb_m/ft^3 (1 g/cm^3) at 70°F (21°C).

Procedure

1. The instrument base should be level.
2. Measure the temperature of the fluid and record on the Drilling Fluid Report.
3. Fill the clean, dry cup with fluid to be tested; put on and rotate the cap until firmly seated. Make sure some of the fluid is expelled through the hole in the cap to free trapped air or gas.
4. When using a pressurized balance, use the pump to add fluid into the cup under pressure. Fill the pump with drilling fluid, place the pump on the cup fittings. Push on the piston until no additional fluid can be added.
5. Wash or wipe the fluid from the outside of the cup. Place the beam on the support and balance it by moving the rider along the graduated scale. The beam is horizontal when the bubble is on center line.
6. Read the density at the side of the rider toward the knife edge.
7. Report the density to the nearest 0.1 lb_m/gal or 0.5 lb_m/ft^3 (0.01 g/cm^3).

Viscosity and Gel Strength

Apparatus

1. Marsh funnel: a simple device for routine measurement of viscosity.

2. Direct-indicating viscometer: used for measurement of plastic viscosity, yield point, and gel strength.
3. Shearometer: used to obtain information concerning shear strength.

Marsh Funnel

The Marsh funnel is dimensioned so that the outflow time of one quart freshwater (946 cm^3) at a temperature of 70° ± 5°F (21° ± 3°C) is 26 ± 0.5 seconds.

Procedure

1. Cover the orifice with a finger and pour a freshly agitated fluid sample through the screen into the clean, dry, upright funnel until the liquid level reaches the bottom of the screen.
2. Quickly remove the finger and measure the time required for the fluid to fill the receiving vessel to the one quart (946 cm^3) mark.
3. Report the result to the nearest second as Marsh funnel viscosity. Report the temperature of the sample in degrees F (°C).

Direct-Indicating Viscometer

Direct-indicating viscometers are rotational-type instruments powered by means of an electric motor or a hand crank.

Procedure

Plastic Viscosity & Yield Point Measurement

1. Place a sample in a suitable container and immerse the rotor sleeve exactly to the scribed line.
2. With the sleeve rotating at 600 rpm, wait for the dial reading to reach a steady value. Record the dial reading for 600 rpm.
3. Shift to 300 rpm and wait for the dial reading to come to a steady value. Record the dial reading for 300 rpm.
4. The plastic viscosity (PV) in centipoise equals the 600 rpm reading minus the 300 rpm reading.
5. The yield point (YP) in $lb_f/100\ ft^2$ equals the 300 rpm reading minus the plastic viscosity. Report the temperature of the sample in degrees F (°C).

6. The apparent viscosity in centipoise equals the 600 rpm reading divided by two.

Gel-Strength Measurement

1. Place the fluid sample in position as in the procedure for plastic viscosity and yield point measurement.
2. Stir at high speed for 10 seconds.
3. Allow the fluid to stand undisturbed for 10 seconds. Slowly and steadily turn the hand wheel in the direction to produce a positive dial reading. The maximum reading is the initial gel strength in $lb_f/100\ ft^2$. For instruments having a 3 rpm speed, the maximum reading attained after starting rotation at 3 rpm is the initial gel strength. Report the temperature of the sample in degrees F (°C).
4. Restir the fluid sample at high speed for 10 seconds and then allow the fluid to stand undisturbed for 10 minutes. Report the measurement as in Step 3 above and report the maximum reading as the 10-minute gel in $lb_f/100\ ft^2$.

Shear Strength Measurement

Experience has shown that some drilling fluids develop excessive shear strength under static conditions, especially at elevated temperatures. Excessive shear strength results in high pump pressures to “break circulation”. High shear strength may also cause difficulties in logging, perforating, and other downhole operations.

The procedure that follows can be used to determine the tendency and estimate the extent to which a drilling fluid will develop excessive shear strength. The measurement is normally made on a static heat-aged fluid sample. The aging temperature is selected to be near the estimated bottomhole temperature of the well. Aging cells or other vessels meeting the temperature requirements of the test are required. Other required equipment includes the stainless steel shearometer tube, a set of weights (gram), a platform for the weights, and a ruler that measures in inches.

Procedure

1. The shear tube is placed and balanced carefully on the surface of the aged and cooled (to room temperature) sample. The platform is placed on top of the tube. If a crust develops on the sample, the crust should be carefully broken before placing the tube.
2. Sufficient weights are placed carefully on top of the platform to start the downward movement of the tube. If the shear strength is low, only the tube and platform may be needed to initiate the movement. It may be necessary to shift the weights on the platform to ensure that the tube’s initial penetration into the fluid is vertical.
3. Unless too much weight is added, the tube will stop its downward travel at the point where the shear strength of the fluid against the surface of the tube is sufficient to support the applied weight. Continue carefully adding weights to the platform until at least half of the length of the tube is submerged.
4. Record the total of the weights used and add the weight of the platform.
5. Measure the length of the non-submerged tube and subtract this value from the total length of the tube to obtain the submerged length.
6. The shear strength of the fluid is calculated from equation

$$S = \frac{3.61(Z+W)}{L} - 0.256A$$

where

S = shear strength ($lb/100\ ft^2$),

Z = weight of shear tube (grams),

W = total shear weight (grams),

L = submerged length of shear tube (inches),

A = fluid weight (lb_m/gal).

Filtration: API Low-Temp/Low-Pressure Test

The API low-temperature/low-pressure fluid loss test uses the standard API filter press pressured to a differential of 100 psi. Pressure can be applied with any nonhazardous fluid medium, either gas or liquid.

To obtain correlative results, one thickness of the proper 9-cm filter paper, Whatman No. 50, S & S No. 576, or equivalent, must be used.

Procedure

1. Be sure each part of the cell is clean and dry, and that the gaskets are not distorted or worn. Pour the sample of fluid into the cell and complete the assembly with the filter paper in place.
2. Place a dry graduated cylinder under the drain tube to receive the filtrate. Close the relief valve and adjust the regulator so a pressure of 100 ± 1.0 psi (690 ± 6.9 kPa) is applied in 30 seconds or less. The test period begins at the time of pressure application.
3. At the end of 30 minutes, measure the volume of filtrate. Shut off the flow through the pressure regulator and open the relief valve carefully. The time interval, if other than 30 minutes, shall be reported.
4. Volume of filtrate should be reported in cubic centimeters (to 0.1 cm^3) as the API filtrate. Report at the start of the test the fluid temperature in degrees F (°C). Save the filtrate for appropriate chemical testing.
5. Disassemble the cell, discard the fluid, and use extreme care to save the filter paper with a minimum of disturbance to the cake. Wash the filter cake on the paper with a gentle stream of water, or with diesel oil in the case of oil fluids. Measure the thickness of the filter cake, and report the thickness in 32nds of an inch or in millimeters.
6. Although standard descriptions are virtually impossible, such notations as *hard, soft, tough, rubbery, firm,* etc. may convey some idea of cake consistency.

Filtration: High-Temp/High-Pressure Test

CAUTION: *Carefully observe the recommendations of the manufacturer on limitations on sample volume and pressure for the test temperature to be used. The instrument consists essentially of a controlled pressure source, a sample cell, a system for heating the cell, and a pressurized collection cell. The filter cell is equipped with a thermometer, thermometer well, oil-resistant gaskets, and support for the filter medium. For temperatures to 400°F (204°C), use filter paper (Whatman No. 50 or equivalent). For temperatures above 400°F (204°C), use a new porous stainless steel disc (Dynalloy X-5 or equivalent) for each test. A valve on the filtrate delivery tube controls flow from the cell. A nonhazardous gas such as nitrogen (preferred) or carbon dioxide should be used for the pressure source. Do not use nitrous oxide gas, which may result in an explosive gas release.*

Procedure: Temperatures < 300°F (149°C)

1. Connect the heating jacket to the correct voltage. Place a thermometer in the thermometer well. Preheat the heating jacket to 10°F (6°C) above selected test temperature.
2. Stir the fluid sample for 10 minutes.
3. Load the cell with the fluid sample, taking care not to fill the cell closer than ½ in. (1.3 cm) from the top. Place the filter paper and close the cell.
4. Place the cell into the heating jacket with both top and bottom valves closed. Transfer the thermometer into the thermometer well.
5. Place the pressure units on the valves and lock in place. Apply 100 psi (690 kPa) to both pressure units with valves closed. Open the top valve and apply pressure to the fluid while heating to the selected temperature.
6. When the sample reaches temperature, increase the pressure of the top pressure unit to 600 psi (4137 kPa).
7. Open the bottom valve. During the test, release the pressure by drawing off the filtrate. Record the total volume.

8. If the filter area is 3.5 in^2 (22.6 cm^2), double the filtrate volume and report.
9. At the end of the test, close both valves, back the T-screw off, and bleed pressure from both regulators.

Note: *Filter cell will still contain approximately 500 psi (3448 kPa). Maintain cell in upright position and cool to room temperature.*

Procedure: Temp. = 300°- 450°F (149°- 232°C)

1. Connect the heating jacket to the correct voltage. Place a thermometer in the thermometer well. Preheat the heating jacket to 10°F (6°C) above the selected test temperature.
2. Stir the fluid sample for 10 minutes.
3. Prepare the cell with the appropriate filtration medium and load it, taking care not to fill the cell closer than 1.5 in. (3.7 cm) from the top.
4. Place the cell into the heating jacket with both top and bottom valves closed. Transfer the thermometer into the thermometer well.
5. Place the pressure units on the valves and lock in place. Apply 450 psi (3103 kPa) to both pressure units with the valves closed. Open the top valve slowly and apply 450 psi (3103 kPa) to the fluid while heating.
6. When the temperature of the sample reaches the selected test temperature, increase the pressure of the top pressure unit to 950 psi (6550 kPa) and open the bottom valve to start filtration.
7. Collect the filtrate for 30 minutes, maintaining the test temperature at ± 5°F (± 3°C). Maintain a back pressure of 450 psi (3103 kPa) during the test.
8. Record the total volume of filtrate, temperature, and pressure. Time of heating of the sample in the filter cell should not exceed one hour.

CAUTION: *Testing at high temperatures and pressures will call for added safety precautions. Pressuring systems and filtrate receiving cells should be equipped with suitable safety relief valves. Heating jackets should be equipped with both an overheat safety fuse and thermostatic cut-off. Vapor pressure of the liquid phase of both water-base and oil-base fluids becomes an increasingly critical design factor as test temperatures are raised.*

Dynamic Filtration: High-Temp/High-Pressure Test

CAUTION: *Carefully observe the recommendations of the manufacturer on limitations on sample volume and pressure for the test temperature to be used. The instrument consists of a controlled-pressure source, a cell, a system for heating the cell, and a variable DC motor. The filter cell is double ended and equipped with a thermometer, thermometer well, oil-resistant gaskets, stirring shaft with packing gland, and support for the filter medium. The standard filter medium is a ¼ in. thick aloxite disc with a permeability of two darcys. Field core can also be cut to be used as the filter medium. Filter paper or stainless steel disc are not recommended for the dynamic tester due to the inability of forming an internal filter cake. The filter medium should be saturated with water in a vacuum chamber so that accurate filtration rates can be measured. A valve on the filtrate delivery tube controls flow from the cell. A nonhazardous gas such as nitrogen should be used for the pressure source.* ***DO NOT USE NITROUS OXIDE GAS WHICH MAY RESULT IN EXPLOSIVE GAS RELEASE.***

Note: *Each filter should be used once only.*

Procedure: Temp. < 300°F (149°C)

1. Connect the heating jacket to the correct voltage. Place a thermometer in the thermometer well. Preheat the heating jacket to 10°F (6°C) above selected test temperature. Adjust the thermostat to maintain the desired temperature.
2. Stir the fluid sample for 10 minutes.
3. Prepare the cell with filter medium, and load it with the fluid sample, taking care not to fill the cell closer than two inches from top. Place top stirring unit in the cell and tighten the allen screws.

4. Place the cell into the heating jacket with valves closed. Transfer the thermometer into the thermometer well.
5. Place the pressure units on the valves and lock in place. Apply 100 psi (690 kPa) to the fluid. Place the drive belt on the stirring shaft and drive motor. While heating to the selected temperature, stir the fluid at a low-shear rate (200 rpm).
6. When the sample reaches the selected temperature, increase the rpm to the desired speed and increase the pressure of the top pressure unit to 600 psi (4137 kPa). Open the bottom valve to start filtration. During the test, cautiously release the pressure by drawing off the filtrate. Record the volume collected at 3, 10, 20, 30, etc. minutes.
7. The filtrate volume should be corrected to a filter area of 7.1 in^2 (45.8 cm^2). If the filter area is 3.5 in^2 (22.6 cm^2), double the filtrate volume at 30 minutes and report.
8. At the end of the test, close both valves, back the T-screw off, and bleed pressure from both regulators.

Note: *Filter cell will still contain approximately 500 psi (3448 kPa). Maintain cell in upright position and cool to room temperature.*

9. When other temperatures, pressures, or times are used, record the temperature, pressure, and time. If the cake compressibility is desired, the procedure can be repeated with pressure of 100 psi (690 kPa on the receiver).

Procedure: Temp. = 300°- 450°F (149°- 232°C)

1. Connect the heating jacket to the correct voltage. Place a thermometer in the thermometer well. Preheat the heating jacket to 10°F (6°C) above the selected test temperature.
2. Stir the fluid sample for 10 minutes.
3. Prepare the cell with the appropriate filtration medium and load it with the stirred fluid sample taking care not to fill the cell closer than 2.5 in. (4.9 cm) from the top.
4. Place top stirring unit in the cell and tighten the allen screws.

5. Place cell into the heating jacket with both valves closed. Transfer the thermometer into the thermometer well.
6. Place the pressure unit on the top valve and lock in place. Lock the bottom pressure receiver to the bottom valve. Apply 450 psi (3103 kPa) to the fluid. Place the drive belt on the stirring shaft and drive motor. While heating to the selected temperature, stir the fluid at a low shear rate (200 rpm).
7. When the temperature of the sample reaches the selected test temperature, increase the rpm to the desired speed, increase the pressure of the top pressure unit to 950 psi (6550 kPa) and open the bottom valve to start filtration.
8. Measure the filtrate at 3, 10, 20, 30, etc. minutes, maintaining the test temperature at ± 5°F (± 3°C). Maintain a back pressure of 450 psi (3103 kPa) during the test. Cautiously reduce the pressure by drawing off a portion of the filtrate. Allow sufficient time for all filtrate to drain from the receiver, and record the total volume of filtrate at 30 minutes, temperature, and pressure. Time of heating of the sample in the filter cell should not exceed one hour.

CAUTION: *Testing at high temperatures and pressures will call for added safety precautions. Pressuring systems and filtrate rate receiving cells should be equipped with suitable safety relief valves. Heating jackets should be equipped with both an overheat safety fuse and thermostatic cut-off. Vapor pressure of the liquid phase of both water-base and oil-base fluids becomes an increasingly critical design factor as test temperatures are raised.*

Retort

The retort is used to determine the quantity of liquids and solids in the drilling fluid. The recommended retort instruments are 10, 20, or 50 cm^3 fluid volume units with external heating jackets.

A fluid is placed in a steel container and heated until the liquid components have been vaporized. The vapors are passed through a condenser and collected in a graduated cylinder and the volume of liquid is measured. Solids, both suspended and dissolved, are determined by the difference.

Procedure

1. Clean and dry the retort assembly and condenser.
2. Collect and prepare the fluid sample.
    - Collect a representative fluid sample and pour it through a 12-mesh Marsh funnel screen. Sample temperature should be within 10°F (6°C) at which fluid density was determined.
    - Mix the fluid sample thoroughly to ensure it is homogeneous, being careful not to entrain any air and ensure no solids remain on bottom of container. Air or gas entrapment in retort sample, will result in erroneously high retort solids due to reduced fluid sample volume.
3. Using a clean syringe, fill retort cup slowly to avoid air entrapment. Lightly tap side of cup to expel air. Place lid on the cup. Rotate lid to obtain a proper fit. Be sure a small excess of fluid flows out of the hole in the lid. Wipe excess fluid from lid, avoid wickingout fluid.
4. Pack retort body with steel wool.
5. Apply lubricant/sealant to threads on retort stem and attach the condenser. Place the retort assembly into the heating jacket. Close insulating lid.
6. Place clean, dry liquid receiver below condenser outlet.
7. Plug in the retort. Allow it to run a minimum of 45 minutes. If fluid boils over into receiver, the test must be rerun. Pack the retort body with a greater amount of steel wool (Step 4) and repeat the test.
8. Allow the liquid receiver to cool. Read and record: (a) total liquid volume; (b) oil volume; and (c) water volume in the receiver.
9. If an emulsion interface is present between the oil and water phases, heating the interface may break the emulsion. After the emulsion interface is broken, allow the liquid receiver to cool. Read the water volume at the lowest point of the meniscus.
10. Unplug retort. Allow to cool before cleaning.

Verification: Retort Cup and Liquid Receiver Volumes

This procedure is used to verify that the retort cup and the liquid receiver meet specifications. Materials needed include: distilled water, a glass thermometer to measure ambient temperature ± 0.1°F (± 0.1°C), and a top-loading balance with precision of 0.01 g.

Procedure for Retort Cup

1. Allow retort cup, lid, and distilled water to reach ambient temperature. Record temperature.
2. Place the clean, empty retort cup and lid on balance and tare to zero.
3. Fill retort cup with distilled water. Place lid on the cup. Rotate lid to obtain proper fit. Be sure a small excess of water flows out of the hole in the lid. Wipe excess water from the lid, avoid wicking-out water.
4. Place filled retort cup with lid on the previously tared balance. Record weight of water (W_w) grams.

Calculation for Retort Cup

1. Calculate the retort cup volume (V_{rc}) using density of water at measured temperature.

$$V_{rc} = \frac{W_{w},\ \mathrm{g}}{\text{Density of water, g/cm}^3} \tag{1-1}$$

Procedure for Liquid Receiver

1. Allow receiver and distilled water to reach ambient temperature. Record temperature.
2. Place the clean, empty receiver with its base on the balance and tare to zero.
3. While the receiver is on the balance, using a pipette or syringe, carefully fill the receiver to the desired graduation mark without leaving water droplets on the walls of the receiver.
4. Record weights for the *incremental volumes* of water at the specific graduation marks (W_{IV}) grams.

Calculation for Liquid Receiver

Calculate the volume of the receiver at each mark (V_m) using density of water at the measured temperature.

$$V_m = \frac{W_{IV,}\ g}{\text{Density of water, g/cm}^3} \tag{1-2}$$

$$\text{Density of water} = (9.99998 \times 10^{-1}) + (6.5368 \times 10^{-5} \times \text{Temp})$$

$$+ \frac{1}{35095 \times 10^{-6} \times \text{Temp}} \tag{1-2a}$$

Estimating Sand Content

Sand content of fluid is estimated by the use of a sandscreen set. The set consists of a 200-mesh sieve 2½ in. (63.5 mm) in diameter, a funnel to fit the screen, & a glass measuring tube.

Procedure

1. Fill the glass measuring tube to the indicated mark with fluid. Add water to the next mark. Close the mouth of the tube and shake vigorously.
2. Pour the mixture onto the clean, wet screen. Discard the liquid passing through the screen. Add more water to the tube, shake, repeat until the wash water passes through clear. Wash the sand retained on the screen to free it of any remaining fluid.
3. Fit the funnel upside down over the top of the screen. Slowly invert the assembly and insert the tip of the funnel into the mouth of the glass tube. Wash the sand into the tube by spraying a fine spray of water through the screen.
4. Allow the sand to settle. From the graduations on the tube read the percent by volume of the sand.
5. Report the sand content of the fluid in percent by volume. Report where the fluid sample was caught, i.e., above shaker, suction pit, etc. Note presence of lost-circulation materials (LCM).

Note: *Use diesel oil for oil-base fluids.*

Measuring pH of Drilling Fluids

Apparatus

Two methods for measuring the pH of drilling fluid are used:

1. a modified *colorimetric* method, using pH paper test strips; and
2. the *electrometric* method, using the glass electrode.

The paper-strip method may not be reliable if the salt concentration of the sample is high. The electrometric method is subject to error in solutions containing high concentrations of sodium ions, unless a special glass electrode is used, or unless suitable correction factors are applied in using the ordinary electrode. A temperature correction should be made in the electrometric method of measuring pH.

Paper Test Strips

Test papers are available in a wide-range type, which permits estimation of pH to 0.5 unit, and in narrow-range papers, with which the pH can be estimated to 0.2 unit.

Procedure

1. Place a 1 in. (25 mm) strip of indicator paper on the surface of the fluid and allow it to remain until the liquid has wetted the surface of the paper and the color has stabilized (usually not more than 30 seconds).
2. Compare the color of the side of the paper which has not been in contact with the fluid with the color standards provided with the test strip and estimate the fluid pH.
3. Report the fluid pH to the nearest 0.5 or 0.2 unit, depending upon the scale of the color chart for the test paper used.

Glass-Electrode pH Meter

The glass-electrode pH meter consists of a glass-electrode system, an electronic amplifier, and a meter calibrated in pH units.

Procedure

1. Make the necessary adjustments to standardize the meter with suitable buffer solutions, according to directions supplied with the instrument.
2. Insert the electrodes into the fluid contained in a small glass vessel. Stir the fluid around the electrodes by rotating the container.
3. Measure the fluid pH according to the directions supplied with the instrument. After the meter reading becomes constant, record the pH to the nearest 0.1 unit.

Note: *For accurate pH measurement, the test fluid, buffer solution, and reference electrode must all be at the same temperature.*

Determining Methylene Blue Capacity

Apparatus

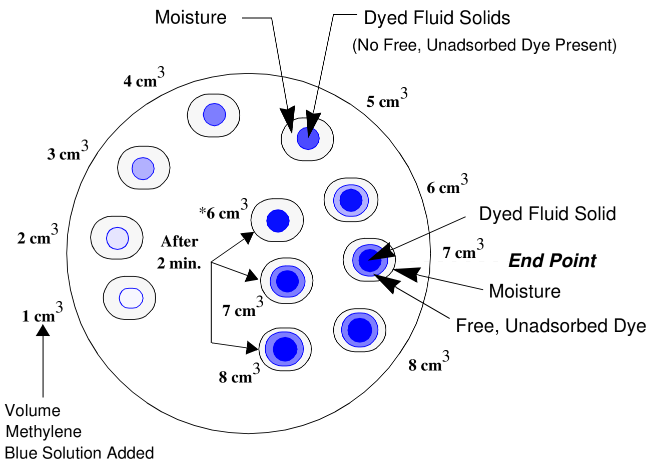
1. Methylene blue solution: 1 mL = 0.01 milli-equivalents, (meq) containing 3.20 g USP grade methylene blue (Cl6Hl8N3SCI) per liter.
2. Hydrogen peroxide: 3% solution
3. Dilute sulfuric acid: approximately 5N
4. Erlenmeyer flask: 250 mL
5. Serological pipettes: one 1 mL and one 5 mL
6. Hot plate
7. Stirring rod
8. Filter paper

Procedure

1. Add 2 mL of fluid (or suitable volume of fluid to require from 2 to 10 mL of reagent) to 10 mL of water in the Erlenmeyer flask. Add 15 mL of 3% hydrogen peroxide and 0.5 mL of sulfuric acid. Boil gently for 10 minutes. Dilute to about 50 mL with distilled water.
2. Add methylene blue solution from the pipette to the flask. After each addition of 0.5 mL, swirl the contents of the flask for about 30 seconds. While the solids are still suspended, remove one drop of liquid and place on the filter paper. The end point is reached when the dye appears as a blue ring surrounding the dyed solids.

3. When the blue tint spreading from the spot is detected, shake the flask an additional two minutes and place another drop on the filter paper. If the blue ring is again evident, the end point has been reached. If the ring does not appear, continue as before until a drop taken after shaking two minutes shows the blue tint. See Figure 1-1.

Figure 1-1 Spot Tests for End Point of Methylene Blue Titration



Note: *Free dye detected immediately after adding the sixth cm^3 is adsorbed after two minutes and indicates that the end points has not been reached.*

4. Report the cation exchange of the fluid as the methylene blue capacity, calculated as

$$\text{Methylene blue capacity} = \frac{\text{mL of methylene blue}}{\text{mL of fluid}} \quad (1\text{-}3)$$

where

$$\text{Bentonite equivalent, } lb_m\text{/bbl fluid} = 5 \times \text{Methylene blue capacity}$$

$(kg/m^3 = 14.25 \times \text{methylene blue capacity})$

Note: *Drilling fluids frequently contain substances in addition to bentonite that absorb methylene blue. Treatment with hydrogen peroxide is intended to remove the effect of organic materials such as CMC, polyacylates, lignosulfonates, and lignites.*

Note: *The cation exchange capacity of clays (shales, etc.) can be determined by the above method. A weighed quantity of clay is dispersed into water by a high-speed stirrer. Titration is carried out as above except that hydrogen peroxide is not added. The cation exchange capacity of clays can be expressed as milli-equivalents of methylene blue per 100 g of clay.*

Chemical Analyses

Determining Chloride Ion Content

Apparatus

1. Silver nitrate solution: containing 4.791 g/L (equivalent to 0.001 g chloride ion per milliliter), preferably stored in an amber bottle
2. Potassium chromate indicator solution: 5 g/100 mL of water
3. Acid solution: 0.02N sulfuric or nitric acid
4. Phenolphthalein indicator solution: 1 g/100 mL of 50% alcohol
5. Calcium carbonate: precipitated, chemically pure grade
6. Distilled water
7. Graduated pipettes: one 1 mL and one 10 mL
8. Titration vessel: 100 to 150 mL, preferably white
9. Stirring rod

Procedure

1. Measure one or more mL of filtrate into the titration vessel. Add two or three drops of phenolphthalein solution. If the indicator turns pink, add acid drop by drop from pipette, while stirring, until the color is discharged. If the filtrate is deeply colored, add an additional 2 cm3 of 0.02 normal (n/50) sulfuric or nitric acid and stir. Then add 1 g calcium carbonate and stir.
2. Add 25 to 50 mL of distilled water and 5 to 10 drops of potassium chromate solution. Stir continuously while adding standard silver nitrate solution drop by drop from the pipette, until the color changes from yellow to orange red and persists for 30 seconds. Record the number of mL of silver nitrate required to reach the end point. If over 10 mL of silver nitrate solution are used, repeat the test with a smaller sample of filtrate.

Note: *If the chloride ion concentration of the filtrate exceeds 10,000 ppm, a silver nitrate solution equivalent to 0.01 g chloride ion/mL may be used. The factor 1000 in the following equation is then changed to 10,000. Report the chloride ion concentration of the filtrate in milligrams per liter (mg/L).*

$$\text{Chloride, mg/L} = \frac{\text{mL of silver nitrate} \times 1000}{\text{mL of filtrate sample}} \qquad (1\text{-}4)$$

Determining Filtrate, Fluid Alkalinity, Lime Content

Apparatus

1. Standardized 0.02N (N/50) acid solution: sulfuric or nitric acid

Note: *Standardized 0.lN (N/10) acid solution may be used for determining the alkalinity of the fluid. Multiply mL acid by 5 if using 0.1N (N/10) acid.*

2. Phenolphthalein indicator solution: 1 g/100 mL of 50% alcohol
3. Methyl orange indicator solution: 0.1 g per 100 cm^3 water

4. Titration vessel: 100 to 150 mL, preferably white
5. Graduated pipettes: one 1 mL and one 10 mL
6. Syringe or serological pipette: 1 mL
7. Stirring rod
8. Glass-electrode pH meter (optional)

Procedure

Filtrate Alkalinity

1. Measure one or more mL of filtrate into the titration vessel. Add two to three drops of phenolphthalein indicator solution. If the indicator turns pink, add 0.02N (N/50) acid, drop by drop from the pipette, while stirring, until the pink color just disappears. If the sample is so colored that the color change of the indicator is masked, the end point is taken when the pH drops to 8.3, as measured with the glass electrode.
2. Report the P_f as the number of mL of 0.02N (N/50) acid required per mL of filtrate.
3. To the sample which has been titrated to the P_f end point, add two or three drops of methylorange indicator solution. Add acid, drop by drop from the pipette, while stirring, until the color of the indicator changes from yellow to pink. If the sample is so colored that the change in color is not evident, the end point is taken when the pH drops to 4.3, as measured with the glass electrode.
4. Report the M_f as the total mL of 0.02N (N/50) acid per mL of filtrate required to reach the methyl orange end point (including that required for the P_f end point).

Fluid Alkalinity

1. Measure 1 mL of fluid into the titration vessel. Dilute the fluid sample with 25 to 50 mL of distilled water. Add four or five drops of phenolphthalein indicator and while stirring, titrate rapidly with 0.02N (N/50) acid or 0.lN (N/10) acid until the pink color disappears. If the sample is masked, the end point is taken when the pH drops to 8.3, as measured with the glass electrode.

2. Report P_m as the number of mL of 0.02N (N/50) acid required per mL of fluid, where

$$P_m = 5 \times \text{mL of 0.1 N acid per mL of fluid.}$$

Lime Content

1. Determine the phenolphthalein alkalinity of the filtrate and the fluid, P_f and P_m.
2. Determine the volume fraction of water in fluid (F_w) using the value from retort assembly.

$$F_w = \frac{\text{\% of water by volume}}{100} \qquad (1\text{-}5)$$

3. Report the lime content of the fluid.

$$\text{Lime, lb}_m\text{/bbl} = 0.26\ (P_m - F_w \times P_f) \qquad (1\text{-}5a)$$

$$\text{Lime, kg/m}^3 = 0.742\ (P_m - F_w \times P_f) \qquad (1\text{-}5b)$$

Determining Total Hardness as Calcium

Apparatus

1. Versenate solution: 1 mL = 400 ppm Ca^{++}
2. Hardness buffer
3. Hardness indicator
4. Distilled water
5. Serological pipettes: one 10 mL and one 5 mL
6. Titrating dish
7. Volumetric pipettes: one 1 mL, one 2-mL, one 5 mL
8. Hot plate (required if filtrate colored)
9. Glacial acetic acid
10. Clorox or equivalent
11. Masking agent: 1:1:2 mixture by volume of triethanolamine:tetraethylene pentamine:water

Procedure

1. Pipette 1.0 mL of fluid filtrate into a titrating dish. If filtrate is clear or only slightly colored, omit Steps 2 through 5.
2. Add 10 mL Clorox and mix.
3. Add 1 mL acetic acid and mix.
4. Boil for 5 minutes. Maintain volume by adding deionized water.
5. Cool and wash the sides of the beaker with deionized water.
6. Dilute to 50 mL with deionized water.
7. Add three measures of hardness buffer and two measures of hardness indicator.
8. Titrate with versenate solution, swirling contents of titrating dish until color of indicator changes from wine red to blue.[1]

Calculation

$$\text{Total hardness as Calcium, mg/L} = \frac{\text{mL of standard versenate} \times 400}{\text{mL of filtrate}} \quad (1\text{-}6)$$

Determining Ca^{++} Only in Fluid Filtrate

Apparatus

1. Pipette: 1 mL
2. Graduated cylinder: 5 mL
3. Calcium indicator: hydroxy naphthol blue
4. NaOH solution: 1N
5. Student burette or 5 mL serological pipette
6. Versenate solution: 1 mL = 400 mg/L Ca^{++}
7. Titrating dish or beaker
8. Measuring scoop

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[1] The presence of soluble iron may interfere with the end point. Should this be suspected, add 1 mL of triethanolamine masking agent and mix prior to adding the hardness indicator.

9. Masking agent: 1:1:2 mixture by volume of triethanolamine:tetraethylene pentamine:water
10. Glacial acetic acid
11. Hot plate

Procedure

1. Pipette 1 to 2 mL of fluid filtrate into a titrating dish or beaker. If filtrate is colorless or only slightly colored, omit steps 2 through 5.
2. Add 10 mL Clorox and mix.
3. Add 1 mL acetic acid and mix.
4. Boil for 5 minutes. Maintain volume by adding deionized water.
5. Cool and wash the sides of the beaker with deionized water.
6. Dilute with 25 to 50 mL of distilled water.
7. Add 3 mL of 1N NaOH.
8. Add one scoop of calcium indicator (hydroxy naphthol blue – do not use total hardness indicator or buffer). If Ca^{++} is present, the solution will turn pink.
9. Add 1 mL of triethanolamine masking agent and mix.
10. Titrate sample with versenate solution to a violet colored end point.

Calculation

$$Ca^{++}\text{, mg/L} = \frac{\text{mL of standard versenate} \times 400}{\text{mL of filtrate}} \quad (1\text{-}7)$$

Determining Magnesium

Procedure

The total mL of standard versenate solution, 1 mL 400 mg/L Ca^{++} used in the determination of total hardness, minus mL standard versenate used in the determination of calcium, times 243 equals the mg/L magnesium.

Calculation

$$\mathrm{Mg}^{++}\text{, mg/L} = \frac{\left(\begin{array}{c}\text{mL of standard versenate,}\\ \text{total hardness}\end{array} - \begin{array}{c}\text{mL of standard}\\ \text{versenate, Ca}^{++}\end{array}\right)\times 243}{\text{mL of filtrate}} \tag{1-8}$$

Example

Assume that 0.75 mL of standard versenate solution is used in the determination of total hardness, and 0.32 mL of standard versenate solution is used in the calcium determination. The mg/L magnesium is then calculated as follows:

0.75 mL – 0.32 mL = 0.43 mL

0.43 mL × 243 = 104.5 mg/L magnesium

Determining Calcium Sulfate

Apparatus

1. Versenate solution: 0.01 Molar EDTA ($C_{10}H_{14}N_2O_8 3Na_2 \bullet 2H_2O$) standardized, 1 mL = 1 mg $CaCO_3$
2. Buffer solution: 7.0 g ammonium chloride and 970 mL ammonium hydroxide (15N) made up to 1 liter with distilled water
3. Hardness indicator solution: Calmagite ($1\text{-}HO\text{-}4\text{-}CH_3\text{-}C_6\text{-}H_3\text{-}N\text{:}N\text{-}C_{10}H_5\text{-}2\text{-}OH\text{-}4\text{-}SO_3\text{-}H$) 1 g per liter in distilled water
4. Titration vessel: 100 to 150 mL, preferably white
5. Graduated pipettes: one 5 mL and one 10 mL
6. Graduated cylinder: 50 mL
7. Distilled water
8. Stirring rod

Procedure

1. Add 5 mL of fluid to 245 mL of distilled water. Stir the mixture for 15 minutes, and then filter through hardened filter paper (Whatman No. 500 S & S No. 576, or equivalent, must be used). Discard the cloudy portion of filtrate.

2. Titrate 10 mL of the clear filtrate to the versenate end point (V_t).
3. Titrate 1.0 mL of filtrate of the original fluid to the versenate end point (V_f).
4. Report the calcium sulfate content.

$$\text{Total calcium sulfate, lb}_m\text{/bbl} = 2.38 \times V_t \tag{1-9}$$

$$\begin{array}{c}\text{Undissolved calcium}\\ \text{sulfate, lb}_m\text{/bbl}\end{array} = 2.38\, V_t - 0.48\, V_f\, F_w \tag{1-9a}$$

Determining Sulfide Content in Fluid Filtrate

The sulfide content of filtrate is converted to H_2S gas in the Garrett Gas Train and quantitatively measured using a Drager tube.

Apparatus

1. The Garrett Gas Train apparatus consists of a transparent plastic gas train, an inert gas supply and pressure regulator, a floating-ball flowmeter, and a Drager tube.
2. Drager H_2S analysis tubes:
   - Low range: marked H_2S 100/a (No. CH-291-01)
   - High range: marked H_2S 0.2%/A (No. CH-281-01)
3. Lead acetate (Hach) paper disks
4. Sulfuric acid: approximately 5N, reagent grade
5. Octanol defoamer in a dropper bottle
6. Hypodermic syringes: one 10 cm^3 with 21-gauge needle (for acid) and one each 10 cm^3 for sample

Procedure

1. Be sure the gas train is clean, dry, and on a level surface.

Note: *Moisture in the flowmeter can cause the ball to float erratically.*

2. With the regulator backed off, install, and puncture a CO_2 cartridge.
3. Add 20 cm^3 deionized water to Chamber 1.
4. Add five drops of octanol defoamer to Chamber 1.
5. See Table 1-1 for sample volume and type of Drager tube required for the expected sulfide range.
6. Select the proper type Drager tube. Break the tip from each end of the tube.
7. Install the tube with the arrow pointing downward into the bored receptacle. Likewise, install the flowmeter tube with the word “Top” upward. Be sure O-rings seal around the body of each tube.
8. Install the top on the gas train and hand tighten all screws evenly to seal.
9. Attach the flexible tubing to the dispersion tube and to the Drager tube.

Note: *Use only latex rubber or inert plastic tubing.* ***Do not clamp flexible tubing****. Unclamped tubing provides pressure relief in event of overpressurization.*

10. Adjust the dispersion tube in Chamber 1 to approximately ¼ in. (0.5 cm) above the bottom.
11. Gently flow CO_2 for a 10-second period to purge air from the system. Check for leaks. Shut off CO_2.
12. Inject a measured volume of the solids-free filtrate sample into Chamber 1 through the rubber septum, using a hypodermic syringe and needle.
13. Slowly inject 10 cm^3 sulfuric acid solution into Chamber 1 through rubber septum using the hypodermic syringe and needle.
14. Immediately restart CO_2 flow. Adjust the rate such that the ball stays between the lines on the flowmeter.

Note: *One CO_2 cartridge should provide about 15 to 20 minutes of flow at this rate.*

15. Observe changes in appearance of the Drager tube. Note and record the maximum darkened length (in units marked on the tube) before the front starts to smear. Continue flowing for a total of 15 minutes, although the front may attain a diffuse, feathery coloration. On the high-range tube, an orange color may appear ahead of the black front if sulfites are present in the sample. Ignore the orange region when recording darkened length.
16. To clean the gas train, remove the flexible tubing and remove the top. Take the Drager tube and flowmeter out of the receptacles and plug the holes with stoppers to keep them dry. Wash out the chambers with warm water and mild detergent, using a brush. Use a pipe cleaner to clean the passages between chambers. Wash, rinse, and then blow out the dispersion tube with air or CO_2 gas. Rinse the unit with deionized water and allow to drain dry.

Note: *A lead acetate (Hach) paper disk fitted under the O-ring of Chamber 3 can be substituted for the Drager tube in the Garrett Gas Train. The lead acetate paper, although not preferred for quantitative analysis, will show the presence of sulfides.*

Calculation

1. Using the measured sample volume, the Drager tube's maximum darkened length, and the Drager tube factor (from Table 1-1), calculate sulfides in the sample.

$$\text{Sulfide, mg/L} = \frac{\text{Darkened length}^{*} \times \text{Factor}}{\text{Sample volume, cm}^{3}} \tag{1-10}$$

*In units marked on the tube.

Table 1-1 Drager Tube Identification, Sample Volumes, and Tube Factors to be used for Various Sulfide Ranges

Sulfide Range (mg/L)	Sample Volume (cm^3)	Drager Tube Identification (see tube body)	Tube Factor (used in calc.)
1.2 to 24	10.0	H_2S 100/a	0.12[a]
2.4 to 48	5.0	H_2S 100/a	0.12[a]
4.8 to 96	2.5	H_2S 100/a	0.12[a]
60 to 1020	10.0	H_2S 0.2%/A	1500[b]
120 to 2040	5.0	H_2S 0.2%/A	1500[b]
240 to 4080	2.5	H_2S 0.2%/A	1500[b]

[a] A tube factor of 0.12 applies to new tubes, H_2S 100/a (Catalog # CH-291-01), with a scale from 100 to 2000. For old tubes, use a factor of 12.

[b] A tube factor of 1500 applies to new tubes, H_2S 0.2%/A (Catalog # CH-281-01), with a scale from 0.2 to 7.0. For old tubes, use factor of 600 times ratio: batch factor/0.40.

Determining Carbonate Content in Fluid Filtrate

Total soluble carbonates include CO_2 and the carbonate (CO_3^{-2}) and bicarbonate (HCO_3^{-}) ions. Fluid filtrate is acidified in a Garrett Gas Train, converting all carbonates to CO_2, which is then evolved by bubbling an inert carrier gas through the sample. The gas stream is collected in a one liter gas bag and subsequently drawn through a Drager tube at a fixed flow rate. The Drager tube responds to CO_2 by progressively staining purple along its length.

Apparatus

1. Garrett Gas Train apparatus
2. Carrier gas: nitrogen (N_2) bottle with low-pressure regulator (preferred) or N_2O gas cartridges (e.g., WHIPPETS #561241 by Walter Kidde and Co. Inc., Belleville, N.J. or equivalent)
3. Drager CO_2 analysis tube: marked CO_2 0.01%/a (No. CH-308-01)
4. Drager one-liter ALCOTEST gas bag (No. 7626425 or equivalent)

5. Drager Multigas Detector hand-operated vacuum pump, Model 31, or equivalent
6. Stopcock (2-way bore), 8 mm glass with Teflon plug
7. Sulfuric acid: approximately 5N, reagent grade
8. Octanol defoamer in a dropper bottle
9. Hypodermic syringes: one 10 cm^3 (for acid) and one 1.0 cm^3, one 5 cm^3, and one 10 cm^3 (for sample)
10. Hypodermic needles: two 1.5 in. (38 mm), 21-gauge

Note: *Nitrogen is preferred over N_2O as the carrier gas. Because N_2O cools upon expansion and chills the diaphragm in the regulator, prolonged N_2O flow will cause the regulator to perform erratically.*

Procedure

1. Be sure that the gas train is clean, dry, and on a level surface, with the top removed.

Note: *If CO_2 has been used as the carrier gas in the previous test (i.e., sulfide analysis), the regulator, tubing, and dispersion tube* ***should be purged with carrier gas at this time****.*

2. Check the bag and pump for leaks. To check the pump, insert a sealed Drager tube into the pump opening and depress bellows. It will remain depressed if pump does not leak.
3. Add 20 cm^3 deionized water to Chamber 1.
4. Add five drops of octanol defoamer to Chamber 1.
5. Install the top on the gas train and hand-tighten evenly to seal all O-rings.
6. Adjust the dispersion tube to approximately ¼ in. (5 mm) off bottom.
7. With regulator backed off, connect carrier gas supply to glass dispersion tube of Chamber 1 using flexible tubing.
8. Flow carrier gas through train for one minute to purge air from the system. Check for leaks in gas train unit.

9. With the bag fully collapsed, install flexible tubing from stopcock bag onto the outlet of Chamber 3.
10. Inject a measured volume of solids-free filtrate into Chamber 1 through septum with hypodermic syringe & needle. See Table 1-2.

Table 1-2 Drager Tube Identification, Sample Volumes, and Tube Factors to be used for Various Carbonate Ranges

Carbonate Range (mg/L)	Sample Volume (cm^3)	Drager Tube Identification (see tube body)	Tube Factor (used in calc.)
25 to 750	10.0	CO_2 100/a	2.5*
50 to 1500	5.0	CO_2 100/a	2.5*
250 to 7500	2.5	CO_2 100/a	2.5*

* A tube factor of 2.5 applies to new tubes, CO_2 100/a (Catalog #8101811), with a scale from 100 to 3000. For old tubes, use a tube factor of 25,000.

11. Slowly inject 10 cm^3 sulfuric acid solution into Chamber 1 through rubber septum using a clean syringe and needle. Gently shake the gas train to mix acid with sample in Chamber 1.
12. Open the stopcock on the gas bag. Restart gas flow and allow gas bag to fill steadily during a 10-minute interval. When bag is firm to the touch (do not burst it), shut off flow and close the stopcock.
13. Break the tip off each end of the Drager tube.
14. Remove the tubing from Chamber 3 outlet and reinstall it onto the upstream end of the Drager tube. Attach Drager hand pump to downstream end of Drager tube.
15. Open the stopcock on the bag. With steady hand pressure, fully depress the hand pump. Release pump so that gas flows out of the bag and through the Drager tube. Ten strokes should empty the bag. More than ten strokes indicates leakage has occurred and test results will not be correct.
16. Record the stain length in units marked on the Drager tube. (Include the faint blue tinge in the purple stain length reading.)

Note: *For best Drager tube accuracy, the Stain Length should fill more than half the tube length, therefore Sample Volume must be carefully selected.*

17. To clean the gas train, remove the flexible tubing and remove the top. Wash out the chambers with warm water and mild detergent using a brush. Use a pipe cleaner to clean the passages between chambers. Wash, rinse, and then blow out the dispersion tube with dry gas. Rinse the unit with deionized water and allow to drain dry. Be sure to periodically replace the disposal gas bag to avoid leaks and contamination in the bag (bag replacement is suggested after 10 analyses).

Calculation

Using the measured *sample volume*, the *drager tube stain length*, and *tube factor* shown in Table 1-2, calculate total soluble carbonates ($CO_2 + CO_3^{-2} + HCO_3^{-}$) in the filtrate sample.

$$\text{Carbonate, mg/L} = \frac{\text{Tube factor} \times \text{Stain length}}{\text{Sample volume, cm}^3} \qquad (1\text{-}11)$$

Measuring Nitrate Ion Concentration

Apparatus

1. Low nitrate calcium hydroxide: 112 lb, jar
2. Vial of capsules: each for making 100 mL of 200 ppm nitrate test standard reagent solution
3. Sealed plastic ampules of NO_3 reagent powder mixture
4. No. 2019 color wheel for 5-minute nitrate test
5. White plastic color comparator box with eight kimax test tubes and No. 1 rubber stoppers
6. Polypropylene test tube rack
7. Graduated cylinder: 10 mL
8. Graduated polypropylene cylinder: 100 mL
9. Transfer pipette: 1 mL
10. Polypropylene beaker: 150 mL
11. Filter papers: 12.5 cm

12. Polypropylene analytical filter funnel
13. Plastic stirring rod
14. Dropping pipette
15. 4 oz. polyethylene bottle with polyseal cap

Procedure

Obtain a suitable sample of solution to be checked.

1. If the sample is a fairly clear and colorless water solution proceed with the test (Step 3).
2. If the sample to be checked is fluid, filter the fluid to obtain 5.0 mL filtrate. If the filtrate is brown, dilute 5 mL of the filtrate to 30 mL with distilled water. Add one tablespoon of low-nitrate calcium hydroxide, shake well, then filter with funnel (dilution is 6:1). Repeat above process until the filtrate is colorless.
3. Select a practical test range and dilute a 4.5 mL sample of the colorless solution. The test range in mg/L nitrate is equal to the number of mL the 4.5 sample is diluted to at this point. For example:
   - 4.5 mL diluted to 10 mL = 10 mg/L at 100 on scale
   - 4.5 mL diluted to 25 mL = 25 mg/L at 100 on scale
   - 4.5 mL diluted to 100 mL = 100 mg/L at 100 on scale
4. Measure 10 mL of well-mixed diluted sample into a test tube. Add contents of one NO- reagent ampule, then stopper and shake for *one full minute*. Place in test tube rack and allow *three minutes* for full color development.
5. Pour 10 mL of same dilution into a test tube and place it in left hole to use as a blank behind color disc. Place the other test tube, in which color has developed, in the right-hand hole and slowly move color disc until color intensities are equal in the two windows when viewed against a reflected white light. Note the wheel reading at pointer and convert to its proper mg/L reading for the dilution selected in Step 3. The scale reading is respective of the dilution selected.

   For example: When diluting 4.5 mL colorless solution to 25 mL (Step 3),

   - Scale reading of 10 = 2.5 mg/L
   - Scale reading of 40 = 1 0 mg/L
   - Scale reading of 75 = 18.75 mg/L
   - Scale reading of 100 = 25 mg/L
6. If the sample color is darker than the wheel color at 100, then estimate the dilution needed to reduce the nitrate ion concentration to the range desired. Make this dilution and run the test again. If the sample color falls within the range of the color wheel and no other dilutions of the 4.5 mL were made, then the wheel reads the nitrate ion concentration of the sample. However, if other dilutions were made as in the case of a dark filtrate, find the concentration of the original sample by multiplying the dilutions made by the concentration in the 4.5 mL sample.
7. For example, if a dark filtrate was subjected to the dilution process twice (Step 2), then the concentration found in the 4.5 mL sample would be multiplied by 36 to obtain the ion concentration of the original sample.

Note: *When figuring the nitrate ion concentration in the original sample, subtract any nitrate added by the calcium hydroxide treatment or the filter paper used.*

Measuring Sulfite Ion Content of Drilling Fluids

Apparatus

1. Mason jar or 400 mL beaker
2. Graduated cylinders: three 10 mL
3. Measuring pipette: 10 mL
4. Volumetric pipettes: one 10 mL and one 25 mL (or comparable syringe)
5. Magnetic stirrer and stirring bar
6. Sodium sulfite solution: 500 mg/L Na_2SO_3
7. Hydrochloric acid: 1:1 HCl
8. Starch solution
9. Potassium iodide solution: 5% KI
10. Standard potassium iodate solution: 0.00625N KIO_3

Procedure

Note: *Method is applicable for determining the sulfite ion content of drilling fluids containing relatively low concentrations of organic materials.*

1. Place 200 to 300 mL deionized water in a 400 mL beaker (or Mason jar).
2. Add 1 to 2 mL of sodium sulfite solution, 10 mL 1:1 hydrochloric acid, 2 mL starch solution, and 5 mL potassium iodide solution.
3. With a measuring pipette, titrate the solution dropwise with 0.00625N KIO_3 to the first appearance of a persistent blue color. (If the end point is inadvertently passed, add another few drops of sodium sulfite solution and again titrate with KIO_3 to the first appearance of a persistent blue color.)
4. By volumetric pipette (or syringe), add 10.0 to 25.0 mL of fluid (freshly received from flow line) to the solution (V_2).
5. With a 10.0 mL measuring pipette, again titrate the solution dropwise with 0.00625N KIO_3 to the appearance of a persistent blue color. Record the volume of KIO_3 required to titrate the fluid sample (V_1).

Calculation

$$\frac{V_1 \times 0.00625 \times 40 \times 1000}{V_2} = \text{mg/L } SO_3^{-2} \qquad (1\text{-}12)$$

Miscellaneous Testing Procedures

Stickometer

Procedure

1. Start with a clean apparatus.
2. Be sure torque plate is clean. Scour face of plate with abrasive cleaning compound (Comet cleanser) until plate shines and rinse thoroughly with water. Then dry carefully.

3. Place filter paper on screen inside chamber. Use “specially hardened filter paper for high pressure filter press.”
4. Place rubber gasket on filter paper.
5. Place plastic gasket on rubber gasket and screw down hold-down ring on gaskets.
6. Center filter paper and gaskets on screen. If gaskets or filter paper extend over small lip around screen, a leak may occur.
7. Place torque plate on filter paper.
8. Fill chamber, within $\frac{1}{8}$ in. of top, with test fluid.
9. Place lid on chamber over torque plate shaft and tighten until lid shoulders against the chamber.
10. Fasten pressure line and tighten pressure release valve.
11. Pull torque plate and tighten nut.
12. Adjust regulator to 500 psi (3448 kPa).
13. Open pressure valve between regulator and chamber and record the time.
14. Allow fluid to filter to desired cake thickness: $\frac{1}{32}$ to $\frac{2}{32}$ inch, as per previous tests, and push torque plate down with lever. Record volume and time.[2] Hold until differential pressure on plate becomes great enough to hold plate down (one to three minutes).
15. Record filtrate volume, time, and torque plate position with dial indicator.
16. Allow plate to stick for five minutes or more and measure torque by rotating plate with torque wrench (always rotate in a clockwise direction).
17. Record set time, filtrate volume, and torque.
18. Repeat Steps 16 and 17 for future readings.

Clean-Up

1. At the conclusion of test, turn off pressure valve between chamber and regulator.

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[2] All subsequent tests on the same fluid should start (after first seating the plate) at the same filtration volume.

2. Open pressure release valve and allow pressure to be released.
3. Disassemble and clean thoroughly.

Calculation of Sticking Coefficients

1. To convert torque (in.-lb) to sliding force (in.-lb), multiply torque by 1.5.
2. The sticking coefficient is the ratio of force necessary to initiate sliding of the plate to the normal force on the plate.
   - **Ratio**

$$\frac{\text{Torque} \times 1.5}{\text{Difference pressure} \times \text{Core area}} = \frac{\text{Torque} \times 1.5}{1570} \qquad (1\text{-}13)$$

3. Sticking coefficients are usually plotted against set time or the total time the plate has been in contact with the filter cake.
4. Example of sticking coefficient calculation using 500 psi (3448 kPa) differential pressure:
   - **Torque reading of 100 in.-lb**

$$\text{Sticking coefficient} = \frac{(100\text{ in.-lb}) \times 1.5}{1570} = 0.0955$$

5. If a differential pressure of 475 psi (3275 kPa) is used the sticking coefficient will equal the torque reading divided by 1000. In the example above, the sticking coefficient would be 0.1.

Determining MIL-GARD Content in Field Fluid

Apparatus

1. Three-chamber Garrett Gas Train
2. Midget CO_2 cartridges
3. Drager H_2S analyses tubes:
   - Low range: marked H_2S 100/a (# CH-291-01)
   - High range: marked H_2S 0.2%/A (# CH-281-01)

4. Lead acetate paper disks (Hach)
5. Filter press apparatus
6. Hamilton Beach mixer or blender
7. Delivery pipettes
8. Sodium sulfide solution: 100,000 mg/L Na_2S
9. Sulfuric acid solution: 1:1 H_2SO_4
10. Defoamer: octyl alcohol

Procedure

1. To 1 bbl equivalent (350 mL) of MIL-GARD® treated fluid, add 2.5 mL of 100,000 mg/L sodium sulfide solution. This amount of sodium sulfide should react with the equivalent of 1.0 lb_m/bbl MIL-GARD.
2. Immediately stir the sample at moderate speed for 15 minutes.
3. Filter the sample to obtain 2.0 mL of filtrate.
4. Analyze 2.0 mL of filtrate per “Determination of Sulfide Content in Drilling Fluid Filtrate.” Either Drager tubes or lead acetate paper may be used to detect residual sulfide.
5. If sulfide is detected by a Drager tube or by a brown coloration of lead acetate paper, the concentration of MIL-GARD is less than 1.0 lb_m/bbl. If sulfide is not detected, repeat Steps 1 through 4, increasing the sodium sulfide content by increments of 2.5 mL until a slight positive sulfide test is obtained. The MIL-GARD concentration is reported as the equivalent concentration at which the last negative results were obtained.

   For example, if 7.5 mL of sodium sulfide solution (3.0 lb_m/bbl MIL-GARD) yields a negative sulfide test and 10.0 mL of sodium sulfide solution (4.0 lb_m/bbl MIL-GARD) yields a positive test, the sulfide scavenging capacity of the fluid is equivalent to approximately 3.0 lb_m/bbl MIL-GARD.

Determining DAP Content of Drilling Fluid

(Adapted from Drilling Specialties Company)

Apparatus

1. Hamilton Beach mixer or blender
2. Filter press
3. Serological pipettes: one 1 mL and one 5 mL
4. Hardness buffer
5. Hardness indicator
6. Measuring scoop
7. $CaCl_2$ solution: 2%
8. Beaker or titrating dish

Procedure

1. Prepare a 5 lb_m/bbl solution of DAP (diammonium phosphate) with a Hamilton Beach mixer or blender. The DAP used in this step should be the same material as that being added to the fluid system.
2. Filter to remove insoluble phosphates.
3. Pipette 1 mL of the filtrate into a titrating dish and dilute with approximately 25 mL of deionized water.
4. Add two scoops of hardness buffer and several scoops of hardness indicator.
5. Titrate the blue solution with 2% $CaCl_2$ (anhydrous) solution until the color changes from blue to red.
6. Calculate factor for the DAP material being used.

$$\frac{5\ lb_m/\text{bbl DAP}}{\text{mL of } CaCl_2 \text{ solution}} = \text{Factor} \qquad (1\text{-}14)$$

7. Repeat the titration, using 1 mL of fluid filtrate and calculate DAP concentration:

$$\text{mL } CaCl_2 \text{ solution} \times \text{Factor} = lb_m/\text{bbl DAP} \qquad (1\text{-}15)$$

Determining Potassium Concentration in Fluid Filtrate: Centrifuge Method

Apparatus

1. Clinical centrifuge tubes: Pyrex, Kolmer-type (Corning #8360) only, 10 mL
2. Centrifuge: horizontal-swing rotor head, manual or electric, 1800 rpm
3. Standard sodium perchlorate solution: 150 g in 100 mL distilled water[3]
4. Standard potassium chloride solution: 14.0 g dry KCl dissolved in distilled water and made up to 100 mL in a volumetric flask, 0.5 mL of standard KCl solution made up to 7.0 mL with H_2O = 1% KCl solution

Preparing Standard Curve for Potassium Chloride

1. Prepare standards over the range of 1% to 8% KCl by adding the appropriate number of milliliters of standard potassium chloride solution (0.5 mL per 1% KCl) to centrifuge tubes and diluting to the 7.0 mL mark with distilled water.
2. Add 3.0 mL of sodium perchlorate solution to each tube.
3. Centrifuge[4] for one minute and read precipitate volume immediately.
4. Plot milliliters of precipitate versus percent potassium chloride, using rectangular graph paper as shown in Figure 1-2.

Field Procedure

1. Measure 7.0 mL of APl filtrate into the centrifuge tube.

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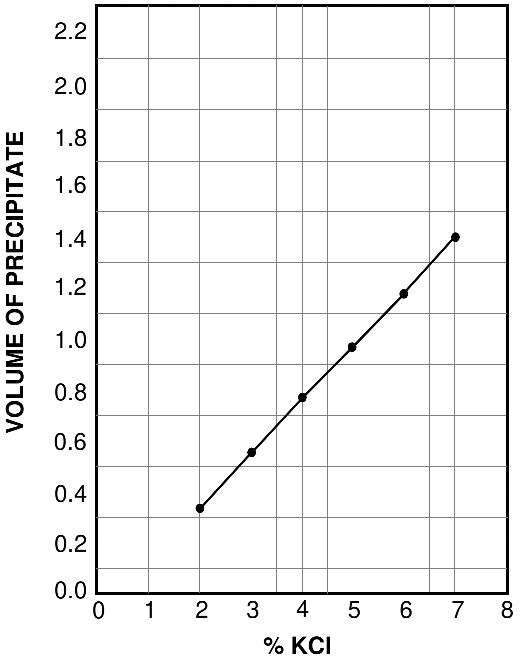
[3] Sodium and potassium perchlorates are explosive in the dry state if heated to a high temperature or allowed to contact organic reducing agents. The perchlorates are not hazardous if kept in water. They will decompose harmlessly if dispersed in a bucket of water and dumped in a remote area.

[4] KCl tests must be made with the same centrifuge used to construct the standard curve. Run the centrifuge at a constant speed, approximately 1800 rpm.

Figure 1-2 KCl Precipitate Curve



2. Add 3.0 mL of sodium perchlorate solution to the tube. If potassium is present, precipitation occurs immediately.[5]
3. Centrifuge for one minute and read precipitate volume immediately.
4. Determine potassium chloride concentration by comparing precipitate volume measured with the standard curve for potassium chloride.

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[5] Salts, lignosulfonates, polymers, clays, and pH do not interfere with the test. The precipitate may become slightly discolored in high-lignosulfonate concentrations, but the test is not affected.

5. Immediately dispose of precipitate by rinsing from tube into bucket of water. Dump water in a remote area of drilling site so that the precipitate can disperse and decompose.

Example

A Boekel hand-driven, two-tube centrifuge is used. Here is how to get approximately 1800 rpm with a hand-driven centrifuge.

1. Determine the number of revolutions of the rotor per each turn of the crank; i.e., very slowly turn the crank and count the number of revolutions of the rotor head during one turn of the crank. We obtain 15 revolutions of the rotor head per one turn of the crank.
2. Determine the number of crank turns it takes to get 1800 revolutions of the rotor head. We get 120 turns per 1800 revolutions (1800/15). If we turn the crank 120 times in one minute, the rotor head speed will be 1800 rpm.
3. To maintain a constant speed for one minute, take the required number of crank turns and divide by 12. This will give the number of crank turns needed per five seconds. We need 10 turns (120/12) per five seconds.
4. Start cranking the centrifuge rapidly and count the number of crank turns in five seconds. If the number of turns is greater than 10, slow down a little and count turns for the next five seconds. If the number of turns is still greater or smaller than 10, adjust your speed accordingly and count turns for the next five seconds. Usually, with a little practice, the required number of turns per five seconds can be achieved within 15 to 20 seconds. Maintain the speed for the remainder of the minute.

High Potassium Chloride Concentrations

The accuracy of the method is dependent upon measuring potassium concentrations between approximately 2% and 8% KCl. If the filtrate potassium concentration is much less than 2% KCl, the method becomes inapplicable.

If the filtrate potassium concentration is greater than 7% KCl, dilution may be accomplished as follows.

1. Pipette 2.0, 3.0, or 4.0 mL of filtrate into the centrifuge tube and dilute with water to the 7.0 mL mark.
2. Correct results by multiplying % KCl by 7, divided by volume of filtrate used (2.0, 3.0, or 4.0 mL).

Determining Potassium Concentration in Fluid Filtrate: STPB Method

(Procedure for Clear Filtrate)

Apparatus

1. Sodium tetraphenylborate (STPB) solution: containing 8.754 g per 100 cm^3
2. Quaternary ammonium salt (QAS) solution: prepared so that 4 cm^3 is equal to 1 cm^3 of the STPB solution
3. Sodium hydroxide solution: 20 g NaOH in 100 cm^3 water
4. Bromophenol blue indicator: 0.04 g of tetrabromophenolsulfonphthalein in 3 cm^3 of 0.lN sodium hydroxide and dilute to 100 cm^3 with water
5. Graduated pipette: 10 cm^3
6. Volumetric pipettes: one 1 cm^3 and one 25 cm^3
7. Volumetric flask: 100 cm^3
8. Funnel: plastic 100 mm diameter
9. Beaker: 150 cm^3
10. Filter paper: Whatman No. 541 or equivalent
11. Titration vessel: 100 to 150 cm^3, preferably white
12. Stirring rod

Procedure

1. Measure one or more cubic centimeters of fluid filtrate into the volumetric flask, add 4 cm^3 of the sodium hydroxide solution, 25.0 cm^3 of the STPB solution and distilled water to 100 cm^3. Mix by shaking and allow to stand 10 minutes. If potassium concentration is greater than 20,000 mg/L, less than 1 cm^3 of filtrate must be used.

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2. If a large amount of precipitate is formed, filter and transfer 25.0 cm^3 into titration vessel. Add 10 to 20 drops of bromophenol blue indicator. Titrate with QAS solution until color changes from purple-blue to light blue.
3. Calculate the potassium ion concentration of the filtrate,

$$\text{Potassium mg/L} = \frac{25\text{cm}^3\ \text{QAS} \times 1000}{\text{cm}^3\ \text{filtrate}} \qquad (1\text{-}16)$$

or, if correction factor is necessary,

$$\text{Potassium mg/L} = \frac{25\text{cm}^3\ \text{QAS} \times \dfrac{4}{\text{Ratio}} \times 1000}{\text{cm}^3\ \text{filtrate}} \qquad (1\text{-}16\text{a})$$

Note: *It is necessary to check the concentration of the QAS solution versus the STPB solution at monthly intervals. To determine the equivalent QAS, dilute 2.0 cm^3 of the STPB solution in a titration vessel with 50 cm^3 distilled H_2O, add 1 cm^3 20% NaOH solution and 10 to 20 drops of the bromophenol blue indicator. Titrate with the QAS solution until color changes from purple-blue to light blue.*

$$\text{Ratio of QAS to STPB} = \frac{\text{cm}^3\ \text{of QAS}}{2.0} \qquad (1\text{-}17)$$

If the ratio is other than 4.0 ± 0.05, it must be used as a correction factor in the calculation.

Oil- and Synthetic-Base Fluids

Determining CARBO-DRILL℠/SYN-TEQ℠ Whole Fluid Alkalinity, Chlorides, & Calcium

Apparatus

1. Solvent: ARCOSOLV® PNP
2. Titration vessel: pint jar or 400 cm^3 glass beaker
3. Phenolphthalein indicator solution: 1 g/100 cm^3 of 50% IPA/water solution
4. Standardized 0.1N (N/10) sulfuric acid solution
5. Potassium chromate indicator solution: 5 g/100 cm^3 water
6. Silver nitrate reagent: 0.282N, containing 47.91 g/L, stored in amber or opaque bottle
7. Distilled or deionized water
8. Disposable syringe: two 5 cm^3
9. Graduated cylinder (TC): one 25 cm^3
10. Serological (graduated) pipettes (TD): two 1 cm^3 and two 10 cm^3
11. Magnetic stirrer with 1.5-inch stirring bar (coated)
12. Calcium buffer solution: 1N sodium hydroxide, kept in a closed, sealed bottle to minimize absorption of CO_2 from air
13. Calcium indicator: Calver II or hydroxy naphthol blue
14. EDTA solution (Versenate or equivalent): 0.1 Molar, disodium (ethylenediamine) tetraacetate dihydrate, standardized (1 cm^3 = 10,000 mg/L $CaCO_3$, 1 cm^3 = 4000 mg/L calcium)

Note: *This EDTA is ten times more concentrated than that used in water-base fluid testing.*

Procedure: Whole Fluid Alkalinity

1. Add 100 cm^3 ARCOSOLV PNP to a 400 cm^3 beaker or pint jar (titration vessel).

2. Fill a 5 cm^3 syringe with whole fluid past the 3 cm^3 mark.
3. Displace 2.0 cm^3 of whole fluid into the titration vessel.
4. Swirl the mixture until it is homogeneous.
5. Add 200 cm^3 distilled water.
6. Add 15 drops of phenolphthalein indicator solution.
7. While stirring rapidly with a magnetic stirrer, slowly titrate with 0.1N sulfuric acid until the pink color just disappears. Continue stirring. If no pink color reappears within one minute, stop stirring.
8. Let the sample stand for five minutes. If no pink color reappears, the end point has been reached. Record the volume of acid used. If a pink color returns, titrate with acid a second time. If a pink color returns after the second titration, titrate with acid a third time and call the total volume of acid used for all three titrations the end point.
9. Calculate the whole fluid alkalinity.

$$P_{om} = \frac{0.1\text{N sulfuric acid, } cm^3}{(\text{fluid sample, } cm)^3} = \frac{0.1\text{N sulfuric acid, } cm^3}{2.0\ cm^3} \qquad (1\text{-}18)$$

To convert this value to lb_m/bbl $Ca(OH)_2$ (lime), multiply by 1.295. If CaO (quicklime) is used to activate the emulsifier, the conversion factor to lb_m/bbl is 0.98.

Procedure: Whole Fluid Chloride

1. Using the same sample as used for the alkalinity procedure, make sure the mixture is acidic by adding 1 to 2 drops, or more, of 0.1N sulfuric acid.
2. Add 10 to 15 drops of potassium chromate indicator solution.
3. While stirring rapidly with a magnetic stirrer, slowly titrate with 0.282N silver nitrate until a salmon pink color remains stable for at least one minute. If a question exists as to if the end point has been reached, it may be necessary to stop the stirring and allow separation of the two phases to occur.

4. Calculate the whole fluid chloride using the volume of 0.282N silver nitrate used.

$$Cl^{-}_{om} = \frac{10{,}000(0.282\text{N silver nitrate, cm}^3)}{\text{oil fluid sample, cm}^3} \qquad (1\text{-}19)$$

Procedure: Whole Fluid Calcium

1. Add 100 cm^3 of solvent to titration vessel.
2. Fill a new 5 cm^3 syringe with whole fluid past the 3 cm^3 mark.
3. Displace 2.0 cm^3 of oil fluid into titration vessel.
4. Cap the jar tightly and shake vigorously by hand for one minute.
5. Add 200 cm^3 distilled or deionized water to the jar.
6. Add 3.0 cm^3 1N sodium hydroxide buffer solution.
7. Add 0.1 to 0.25 g Calver II indicator powder.
8. Recap the jar tightly, shake vigorously again for two minutes. Set jar aside for a few seconds. If a reddish color appears in the aqueous (lower) phase, calcium is present. Continue the test.
9. Place the jar on the magnetic stirrer and drop in the stir bar. Begin stirring without mixing upper and lower phases.
10. Titrate slowly, adding EDTA (Versenate). When a distinct color change from reddish color to a blue-green color occurs, the end point is reached. Record the volume of EDTA titrated.
11. Calculate the whole fluid calcium using the volume of EDTA used.

$$Ca^{++}_{om} = \frac{4000\ (0.1\text{M EDTA cm}^3)}{\text{oil fluid sample, cm}^3} \qquad (1\text{-}20)$$

Measuring Water, Oil, and Solids

The direct retort reading provides oil, water, and solids measurements. The synthetic- or oil-base fluid is composed

of oil, brine, and solids, therefore, the solids and water content must be adjusted for the presence of the salt.

Description

The retort instrument facilitates the separation and measurement of oil and water volumes and the estimation of solids content in a sample of oil-base or invert emulsion fluid.

Retort tests are performed to determine the water content of oil-base fluid systems. This measurement is critical for proper control of fluid composition and fluid properties. Percent water is also used in the calculation of results from other tests, i.e., aqueous phase salinity of an oil-base fluid. In addition, the retort data measures the percentage of oil. Knowing the ratio of oil to water in a fluid is necessary for controlling fluid rheology, density, and filtration.

Test results providing solids content of oil-base fluids are not as accurate as the data obtained in the water-base fluid retort test. Nonetheless, solids content can be estimated from retort data for use in monitoring solids buildup and solids control in oil-base fluids.

Equipment

Retorts of two sizes (10 cm^3 and 20 cm^3) are commonly available and consist of the following components.

1. Sample cup
2. Heating element
3. Temperature controller: should limit temperature of retort to 930°F (± 70°F) [500°C (± 20°C)]
4. Liquid condenser
5. Liquid receiver: Kolmer-type clinical centrifuge tube, Pyrex®, or equivalent glass, transparent and inert to oil, water, salt solution, and temperatures up to 90°F (32°C)

Other Required Equipment

1. Hand cranked or electric centrifuge which is capable of holding at least two liquid receivers and having a speed of at least 1800 rpm
2. Fine steel wool (i.e., No. 000)

Note: *Liquid steel wool is not recommended.*

3. High-temperature silicone grease: used for a thread seal and a lubricant
4. Pipe cleaners
5. Putty knife or spatula with blade shaped to fit the inside dimensions of the retort sample cup

Procedure

Note: *Procedure will vary depending on type or retort used. See manufacturer's instructions for complete procedure.*

1. Ensure the retort sample cup, condenser passage, and liquid receiver are clean, dry, and cooled from previous use.
   - Thoroughly clean inside the sample cup (and lid) prior to each test. Periodically, lightly polish the interior of the sample cup with steel wool.
   - Using pipe cleaners, clean (and dry) the condenser passage before each test.
2. Collect a sample of oil-base fluid and let it cool to approximately 80°F (26°C). To remove LCM, large cuttings, and other debris, filter the sample through 12-mesh screen on the Marsh Funnel.
3. Stir the fluid slowly for 2 to 3 minutes to release gases.
4. Using a light coating of silicone grease, lubricate the threads on the sample cup and condenser tube. This prevents vapor loss through the threads and facilitates equipment disassembly and cleanup after testing.
5. To prevent boilover of solids into the liquid receiver, lightly pack a ring of steel wool into the chamber above the sample cup.

Note: *The correct amount of steel wool is determined from experience.*

6. Fill the retort sample cup with gas-free oil fluid, from Step 3.
7. Carefully position the lid on the sample cup. Allow an overflow of the sample through the hole in the lid. This ensures that the correct volume of gas is in the cup.

8. Holding the lid tightly in place, wipe the overflow from the sample cup and lid. Make certain the sample cup threads are still covered with silicone grease after wiping, and that the hole in the lid remains unplugged.
9. Screw the retort cup onto the retort chamber with its condenser.
10. Place a clean, dry liquid receiver under the discharge tube of the condenser.
11. Heat the retort and observe the liquid falling from the condenser. Continue heating for 10 minutes beyond the point where condensate collection stops, which may be as long as 45 minutes for some tests.
12. Remove the liquid receiver tube from the retort. Note the total volume of liquid recovered (oil plus water). Note if any of the recovered liquid contains solids. If so whole fluid has boiled over from the sample cup and steps 3 to 11 must be repeated.
13. Place the liquid receiver tube into one of the tube holders of the centrifuge rotor head.
14. Select an empty liquid receiver tube and fill it with water to a weight approximately equal to the receiver tube from the test. This tube will be used as a counterbalance in the centrifuge.
15. Place the counterbalance tube into the centrifuge tube holder on the side opposite the retort sample tube.
16. Spin the tubes in the centrifuge for at least 2 minutes at 1800 rpm.
17. If an emulsion band exists between the oil and water layers after spinning, warm the tube to about 120°F (49°C) before centrifuging again.
18. Allow the liquid receiver to cool to 75°F ± 25°F (24°C ±14°C). Read volumes of oil and water. Record volumes (or volume %) of water and oil collected.

Calculation

Using the measured volumes of oil and water and the volume of the original whole fluid sample (10 cm^3 or 20 cm^3), calculate the volume percent water and oil and estimate the volume percent solids in the fluid.

$$Volume\ \%\ water,\ V_W = \frac{100\ (volume\ of\ water,\ cm^3)}{volume\ of\ sample,\ cm^3}$$

$$Volume\ \%\ oil,\ V_O = \frac{100\ (volume\ oil,\ cm^3)}{volume\ of\ sample,\ cm^3}$$

Oil/Synthetic Fluid Lime, Salinity, Solids, & Fluid/Water Ratio Calculations

Equations and test procedures allow calculations for the lime content of the fluid, the $CaCl_2$ and/or NaCl content in the whole fluid, the $CaCl_2$ and/or NaCl in the brine phase, the low-density solids (NaCl and/or drill solids) content, and the high-density solids content. These equations do not utilize a “lime correction” for adjusting calcium content as determined by the calcium titration.

The following calculations and their respective Salt Tables (found in Chapter 5) may vary from other reference material. The information presented is based upon work being done by the API. Data known for these calculations include

ρ_{HDS} = density of weighting material,

ρ_{LDS} = density of drilled solids,

ρ_O = density of oil.

Data obtained from testing procedures previously enumerated include

P_{om} = whole fluid alkalinity
(cm^3 0.1N H_2SO_4/cm^3 fluid),

$Ca^{+2}{}_{om}$ = whole fluid calcium (mg/L),

$Cl^-{}_{om}$ = whole fluid chloride (mg/L),

V_O retort volume % oil,

V_W retort volume % water.

---

1. Total lime content:

   Lime hydrate [$Ca(OH)_2$], lb_m/bbl = 1.295(P_{om})

   Quicklime [CaO], lb_m/bbl = 0.98(P_{om})

2. Total $CaCl_2$ and NaCl content:

   The chloride ion associated with $CaCl_2$ based upon the $Ca^{+2}{}_{om}$ analysis is

$$Cl^-_{CaCl_2} = 1.77\left(Ca^{+2}_{om}\right) \tag{1-21}$$

where

$Cl^-_{CaCl_2}$ = mg Cl^-/L of fluid from $CaCl_2$.

Note: *If* $Cl^-_{CaCl_2} \ge Cl^-{}_{om}$, *then assume that only* $CaCl_2$ *is present in the fluid and no NaCl is present; go to Eqn. 1-27 and skip Eqns. 1-22 through 1-26.*

$$CaCl_{2_{om}} = 2.774(Ca^{+2}_{om}) \tag{1-22}$$

where

$CaCl_{2_{om}}$ = mg $CaCl_2$/L of fluid;

$$CaCl_{2_{salt}} = 9.71 \times 10^{-4}(Ca^{+2}_{om}) \tag{1-23}$$

where

$CaCl_{2_{salt}}$ = lb_m calcium chloride per bbl of fluid;

$$Cl^-_{NaCl} = Cl^-{}_{om} - Cl^-_{CaCl_2} \tag{1-24}$$

where

$Cl^-{}_{NaCl}$ = mg Cl^-/L of fluid from NaCl;

$$NaCl_{om} = 1.65\ (Cl_{NaCl}) \tag{1-25}$$

where

$NaCl_{om}$ = mg NaCl/L of fluid;

$$NaCl_{salt} = 3.5 \times 10^{-4}\,(NaCl_{om}) \qquad (1\text{-}26)$$

where

$NaCl_{salt}$ = lb_m sodium chloride per bbl of fluid.

Omit Eqns. 1-27 and 1-28.

If the test Eqn. 1-22 indicates that all of the chloride ion occurs from $CaCl_2$, the following equations are used:

$$CaCl_{2_{om}} = 1.57\,(Cl^{-}_{om}) \qquad (1\text{-}27)$$

where

$CaCl_{2_{om}}$ = mg $CaCl_2$/L of fluid;

$$CaCl_{2_{salt}} = 3.5 \times 10^{-4}\left(CaCl_{2_{om}}\right) \qquad (1\text{-}28)$$

where

$CaCl_{2_{salt}}$ = lb_m $CaCl_2$ per bbl of fluid.

Aqueous Phase Salt Calculations

Accurate salt calculations prevent the oversaturation of the brine with $CaCl_2$, which can lead to severe water wetting problems in the fluid system. The percent by volume solids, as determined by the retort, must be adjusted for the calculated salt volume that is retained in the retort assembly. This correction can be accomplished with simple calculations.

The following equations are designed to calculate the quantity of NaCl and $CaCl_2$ in the aqueous phase of the CARBO-DRILL^{SM} and SYN-TEQ^{SM} systems.

$$W_C = \frac{100\,(CaCl_{2_{om}})}{CaCl_{2_{om}} + NaCl_{om} + 10{,}000\,(V_W)} \qquad (1\text{-}29)$$

where

W_C = wt % $CaCl_2$ in brine,

V_W = volume% retort water.

$$CaCl_{2_{ppm}} = 10,000\,(W_C) \qquad (1\text{-}29a)$$

$$W_N = \frac{100\,(NaCl_{om})}{CaCl_{2_{om}} + NaCl_{om} + 10{,}000\,(V_W)} \qquad (1\text{-}30)$$

where

W_N = wt % NaCl in brine.

$$NaCl_{ppm} = 10,000\,(W_N) \qquad (1\text{-}30a)$$

Check mutual solubility of NaCl and $CaCl_2$, or use Figure 1-3.

$$W_{Nmax} = 26.432 - 1.0472\,(W_C) \qquad (1\text{-}30b)$$

$$+\,7.98191\,(10^{-3})\,(W_C) + 5.2238\,(10^{-5})\,(W_C)^3$$

where

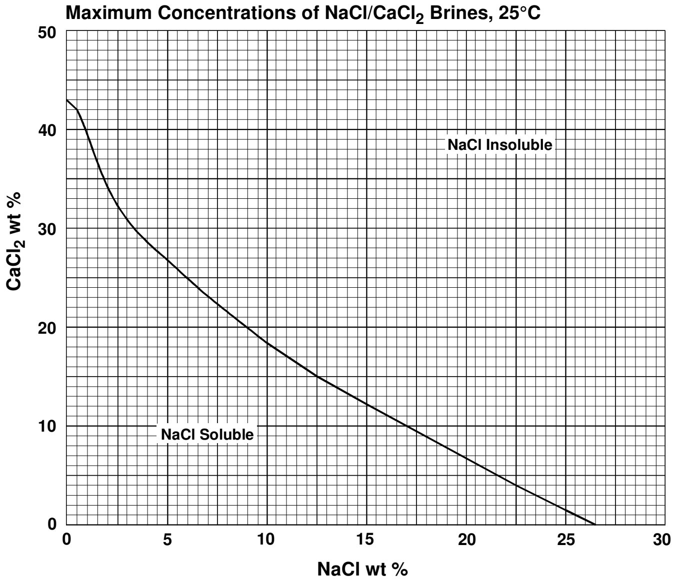
W_{Nmax} = maximum wt % NaCl in $CaCl_2$/NaCl brine at 25°C (77°F).

Mutual Solubility

Check Figure 1-3 or Eqn. 1-30b to determine the weight percent of sodium chloride, W_N, that is totally soluble in the $CaCl_2$/NaCl brine solution at 25°C (77°F).

If the calculated W_N is not totally soluble, a portion of the NaCl is a solid in the oil-base fluid.

Figure 1-3 Mutual Solubility Between NaCl and $CaCl_2$ at 25°C



$$W_{Nmax} = 26.432 - 1.0472(W_C) + 7.98191(10^{-3})(W_C)^2 + 5.2238(10^{-5})(W_C)^3$$

If the W_N is not totally soluble, the results of Eqns. 1-30 and 1-31 are not correct. They must be recalculated using a fraction of W_N as the $NaCl_{om}$, until the ratio of $\frac{W_{Nmax}}{W_N}$ is greater than 0.95. The following steps are used to determine more accurate salt solubilities.

Calculate the $NaCl_{ratio}$ to determine the accuracy of W_N.

$$NaCl_{ratio} = \frac{W_{Nmax}}{W_N} \qquad (1\text{-}30c)$$

---

where

$NaCl_{ratio}$ = the ratio of the maximum soluble wt % NaCl to the calculated wt % NaCl in the brine.

If $NaCl_{ratio}$ is greater than 0.95 proceed to Eqn. 1-31. Otherwise, the values for W_C (Eqns. 1-29 and 1-29a), W_N (Eqns. 1-30 and 1-30a), and W_{Nmax} (Eqn. 1-30b) must be recalculated using the value $NaCl_{om}$ as a *new* value calculated by

$$NaCl_{om_n} = NaCl_{ratio}\,(NaCl_{om}) \qquad (1\text{-}30d)$$

where

$NaCl_{om_n}$ = the new $NaCl_{om}$ to be used in Eqns. 1-29 through 1-30.

After substituting the new $NaCl_{om_n}$ in Eqns.1-29 through 1-30, recalculate the $NaCl_{ratio}$ (Eqn. 1-30c) using the new values. If $NaCl_{ratio}$ is still less than 0.95 the above procedures must be repeated.

Use **only** the soluble NaCl portion from the graph or equation iterations as the value of W_N in future equations. The remaining salt will be calculated as a solid in the following analysis.

The brine density of the mixed salt brine is calculated as

$$\rho_B = 0.99707 + 6.504\,(10^{-3})\,(W_N) + 7.923\,(10^{-3})\,(W_C) + 8.334\,(10^{-5})\,(W_N)\,(W_C) + 4.395\,(10^{-5})\,(W_N)^2 + 4.964\,(10^{-5})\,(W_C)^2 \qquad (1\text{-}31)$$

where

ρ_B = brine density (g/cm^3).

Note: *The density of single-salt brines can be found using the values or equations found in the* Chapter 5.

mg/L Salt

Weight percent units are based upon the density of the brine, as well as the salt content. The salt concentration, expressed as mg/L, is

$$CaCl_{2\,mg/L} = 10,000\ (W_C)\ (\rho_B) \tag{1-32}$$

$$NaCl_{mg/L} = 10,000\ (W_N)\ (\rho_B) \tag{1-33}$$

Solids Calculations

As mentioned previously, the solids content, measured from the retort testing procedure, must be corrected for the salt from the brine that remains in the retort assembly.

The corrected volume % brine is

$$V_B = \frac{100\ (V_W)}{\rho_B\ [100 - (W_N + W_C)]} \tag{1-34}$$

where

V_B = volume % brine.

The corrected volume % solids is

$$V_S = 100 - (V_O + V_B) \tag{1-35}$$

where

V_S = volume % corrected solids,

V_O = volume % retorted oil.

The solids in CARBO-DRILL^{SM}/SYN-TEQ^{SM} systems consist of low-density solids, usually drill solids, and high-density solids, generally MIL-BAR® or DENSIMIX®.

The average density of all suspended solids is

$$\rho_S = \frac{[100\ (MW)] - [(V_O)\ (\rho_O)] - [(V_B)\ (\rho_B)\ (8.345)]}{8.345\ (V_S)} \tag{1-36}$$

where

ρ_S = average density of solids (g/cm^3),

ρ_O = oil density (lb$_m$/gal),

MW = drilling fluid density (lb$_m$/gal).

The average density of suspended solids can be divided into the volume and weight of high-density and low-density solids.

The volume% high-density solids is

$$V_{HDS} = \frac{\rho_S - \rho_{LDS}}{\rho_{HDS} - \rho_{LDS}} \times V_S \tag{1-37}$$

where

V_{HDS} = volume % high-density solids,

ρ_{HDS} = density of high-density solids (g/cm^3),

ρ_{LDS} = density of low-density solids (g/cm^3).

The concentration of high-density solids is

$$M_{HDDS} = 3.5\ (\rho_{HDS})\ (V_{HDS}) \tag{1-38}$$

where

M_{HDS} = high-density solids (lb$_m$/bbl).

The volume of low-density solids is

$$V_{LDS} = V_S - V_{HDS} \tag{1-39}$$

where

V_{LDS} = volume % low-density solids.

The concentration of low-density solids is

$$M_{LDS} = 3.5\ (\rho_{LDS})\ (V_{LDS}) \tag{1-40}$$

where

M_{LDS} = low-density solids (lb$_m$/bbl).

Fluid/Water Ratio Calculations

The fluid/water ratio relates the oil or synthetic fluid and freshwater fractions as a percent of the liquid retort fraction. The fluid/brine (salt-content-corrected water) ratio relates the liquid fraction of the fluid as the ratio of oil or synthetic fluid and brine fractions. The fluid/brine ratio is the most meaningful ratio, since it relates more closely the liquid fractions of the drilling fluid. Oil/brine ratio is important when engineering most CARBO-DRILL$^{\text{SM}}$ systems, in that it can have a major effect on viscosity and/or filtrate loss.

The *oil/water* ratio is

$$W_R = \frac{100(V_W)}{V_O + V_W} \tag{1-41}$$

where W_R = water % in the ratio.

The oil % in the ratio (O_R) is

$$O_R = 100 - W_R \tag{1-41a}$$

The more accurate and useful ratio is the *oil/brine* ratio. The oil/brine ratio is

$$B_R = \frac{100(V_B)}{V_O + V_B} \tag{1-42}$$

where B_R = brine % in the ratio.

The oil % in the ratio (O_R) is

$$O_R = 100 - B_R \tag{1-42a}$$

Nomenclature

ρ_B = brine density

ρ_{HDS} = density of high-density solids (weight material)

ρ_{LDS} = density of low-density solids

ρ_O = density of oil

ρ_S = average density of solids

B_R = brine % in the ratio

Ca^{++} = calcium ion

Ca^{+2}_{om} = whole fluid calcium

$CaCl_{2_{add}}$ = additions of $CaCl_2$ to system volume

$CaCl_{2_{mg/L}}$ = mg/L of $CaCl_2$ in internal phase (brine density dependent)

$CaCl_{2_{om}}$ = mg $CaCl_2$/L of fluid

$CaCl_{2_{ppm}}$ = ppm of $CaCl_2$ in internal phase

$CaCl_{2_{salt}}$ = lb_m/bbl $CaCl_2$/bbl of fluid

Cl^- = chloride ion

$Cl^-_{CaCl_2}$ = chloride content from the $CaCl_2$ brine

Cl^-_{NaCl} = chloride content from the NaCl brine

Cl^-_{om} = whole fluid chloride

EDTA = ethylenediamine tetraacetate dihydrate

ES = electrical stability

F_B = volume of brine

F_O = volume of oil

F_W = volume of water

HT/HP = high-temperature/high-pressure

IPA = isopropanol

M_{HDS} = concentration of high-density solids

M_{LDS} = concentration of low-density solids

M_W = drilling fluid density

Na^+ = sodium ion

$NaCl_{om}$ = mg NaCl/L of fluid

$NaCl_{om_n}$ = adjusted mg/L of NaCl in internal phase when W_{Nmax}/W_N ratio is less than 0.95

$NaCl_{mg/L}$ = mg/L of NaCl in internal phase (brine density dependent)

$NaCl_{ppm}$ = ppm of NaCl in internal phase

$NaCl_{ratio}$ = ratio of maximum % NaCl to wt % NaCl

$NaCl_{salt}$ = lb_m/bbl NaCl/bbl of fluid

O_R = oil % in the ratio

P_{om} = whole fluid alkalinity

R_B = required brine ratio

R_O = required oil ratio

V_B = volume % brine

V_{EDTA} = volume of EDTA/cm^3 of fluid

V_{HDS} = volume % high-density solids

V_{LDS} = volume % low-density solids

V_O = retort volume % oil

V_S = volume % corrected solids

V_{SN} = volume of silver nitrate

V_W = retort volume % water

Vol_{sys} = system volume

W_C = wt % $CaCl_2$ in brine

W_N = wt % NaCl in brine

W_{Nmax} = max. wt % NaCl in $CaCl_2$/NaCl brine @ 25°C

W_R = water % in the ratio

Determining Electrical Stability

Equipment

Electrical Stability Meter

Procedure – Equipment Test

1. Run a voltage ramp test with the electrode probe disconnected, following instructions in the ES meter operating manual. If the meter is working properly, the ES reading should reach the maximum voltage permitted by the instrument.
2. With the electrode probe connected to the ES meter, repeat the voltage ramp in air. The ES reading should reach the maximum permitted voltage. If the maximum reading is not recorded, reclean or replace probe.
3. Repeat the voltage ramp test with the electrode probe in tap water. The ES reading should not exceed 3 volts. If ES does exceed 3 volts, reclean or replace electrode.
4. Check the accuracy of the ES meter with standard resistors and/or Zener diodes. The ES readings should fall within 2.5% of the expected values; if any of the ES readings fall outside this range, the instrument should be returned to the supplier for adjustment or repair.

Procedure – Measurements

1. Screen sample through 12-mesh screen (Marsh Funnel) and place in viscometer heating cup. Heat sample to 120° ± 5°F (50 ± 2°C).
2. The electrode probe can be cleaned using the base oil of the fluid system. After cleaning, the probe should be dried thoroughly.
3. Hand-stir the 120°F (50°C) sample with the electrode probe for approximately 10 seconds to ensure that the composition and temperature of the fluid are uniform. Position the electrode probe so that it does not touch the bottom or sides of the container, and be sure that the electrode surfaces are completely covered by the sample.
4. Initiate the voltage ramp. Follow the procedure described in the ES meter operating manual. Do not move the electrode probe during the voltage ramp.

5. At the conclusion of the test, note the ES value displayed on the readout device.
6. Repeat this test. The two ES values should not differ by more than 5%. If the values should differ by more than 5%, check the meter or electrode probe for malfunction.
7. Record the average of the two ES measurements on the fluid report.

Determining Relative Humidity (Activity)

Apparatus

The hygrometer is a precision ammeter equipped with a sensing probe that is sensitive to humidity.

Note: *The probe must not come in direct contact with any liquid, or be touched with the fingers.*

A clean, soft brush may be used to remove dust. Otherwise, handle the probe carefully by its rubber stopper only.

Procedure

Hygrometer – Digital Model

1. Prepare saturated solutions of the following salts.

Salt	a_w	Salt / 100 cm^3 H_2O
Calcium chloride	0.295	100 g
Calcium nitrate	0.505	200 g
Sodium chloride	0.753	200 g
Potassium nitrate	0.938	200 g

Table 1-3 Preparation and Activity of Saturated Salt Solutions

2. The solutions are prepared by adding the indicated amount of salt to 100 cm^3 of distilled or deionized water, stirring at an elevated temperature between 150° and 200°F (66° and 93°C) for one-half hour, then cooling to a temperature between 75° and 80°F (24° and 27°C). Solid salt must be visible in the bottom after equilibration.

   If no crystals are visible, some additional crystals or grains of the same salt should be added to induce precipitation. This is often necessary with calcium chloride. (Salts of reagent-grade purity are recommended. However, if necessary, field-grade NaCl or $CaCl_2$ can be substituted.)

3. Use a small wide-mouth jar of approximately 150 cm^3. The container should have a flexible elastomer cap which, when bored through, will form an air-tight seal around the shaft of a sensor probe. An example of such a container is the Fleaker, manufactured by Dow Corning.
4. Use an insulating cover made of synthetic foam for the wide-mouth jar. The cover should fit snugly and should insulate the side and bottom of the jar from temperature fluctuations.

Calibration of Hygrometer

1. Prepare the known relative humidity standard solutions. A total volume of 40 cm^3 is sufficient in each sample container. These solutions must be kept firmly capped to prevent spillage, evaporation, or contamination.
2. Desiccate the probe with anhydrous calcium chloride in a sample container. (Calcium sulfate “drierite” or silica gel may be used.) Place the sensor probe with cap in the air space above the salt. Wait 10 to 15 minutes. A reading indicating the probe is dry would be ≤ 24% RH.

Note: *Keep a distance of ½ in. (12 mm) between the sensing probe and desiccant and maintain the same distance for salt solutions and fluid samples. Never contact the probe directly with any samples or solutions.*

3. Transfer the probe and container cap to the first (lowest a_w) standard solution and allow 30 minutes for equilibrium to be reached. Allow each standard to equilibrate the same length of time. Record temperature and % RH.
4. Remove the probe from the first solution and place into the container with the second known solution. Measure the humidity for each solution going from the lowest to the highest a_w. A minimum of 2 solutions – one low humidity, one high humidity – must be used. Sodium and calcium chloride are recommended.

5. When complete data are obtained, plot % RH versus a_w on graph paper. This calibration graph is used to find the correct oil fluid activity.

Note: *The temperature of the standards and fluid samples should be maintained at 75°F to 77°F (24°C to 25°C) because the a_W values by the literature are within this range.*

Measuring Fluid Activity (a_{wm})

1. Desiccate the probe as described previously for 10 to 15 minutes.
2. Put a sample of room-temperature fluid (40 cm^3) in to the sample container. Insert the probe in to the air space ½ in. (12 mm) above the fluid surface. Turn on the hygrometer, wait 30 minutes (the same length of time as used for the calibration standards), and read and record % RH and temperature. Read the a_{wm} from the calibration graph.

Note: *Examine the fluid to assure that separation has not occurred. Separation of an oil layer will lead to erroneous readings. Make sure that the sample container and cap are clean and free of salt before each new sample is tested.*

3. To measure the a_{ws} of shale, obtain a sample of cuttings (approx. 100 g) from the shale shaker and wash with diesel oil or synthetic fluid to remove adhering drilling fluid. Carefully blot all traces of cleaning fluid or invert fluid from cuttings with paper. Test, using the hygrometer as outlined for fluid testing.

Note: *Freshwater or brine cuttings cannot be expected to yield useful a_{ws}, data. Shale a_{ws} must be measured on cuttings that have not been water-wet with drilling fluids. To measure a_{ws} on brine or water-base drilled shale, a core must be cut and inner shale pieces selected for measurement.*

Hygrometer – Analog Model

1. Connect probe to the socket in the face of the instrument. Leave the protective basket around the probe until ready to test % RH.
2. Connect the grounded plug to 115-volt AC.
3. Turn the control knob to the CHECK position, and observe the indicator needle for check position alignment, as shown on the meter. If the indicator needle does not align with the red check mark, set the needle with the smaller balance knob.
4. Calibration fluids, as outlined under instructions for digital models, must be available for construction of a calibration curve. After mixing the saturated solutions, pour approximately 75 to 100 mL into each Erlenmeyer flask and stopper each until ready for use.
5. After allowing the samples to reach ambient temperature, carefully insert the probe into the flask containing the saturated $CaCl_2$ solution. Seat the stopper firmly. Flasks should be set upright inside cut-outs in the case so there is no danger of the contents coming in contact with the probe.
6. Recheck the CHECK position as outlined above. Then, move the control knob to READ. Allow reading to stabilize 20 to 30 minutes. Note this meter reading and plot the reading opposite 0.32 on standard graph paper. *Do not* change the meter setting from the CHECK balance point. Corrected a_w readings will be read from the graph after calibration is completed.
7. After obtaining a reading with the saturated $CaCl_2$ solution, place the probe in to the flask containing the sodium chloride saturated solution. Recheck the CHECK point setting and then switch control knob to READ and allow the meter to stabilize. Plot the meter reading opposite 0.75 a_w on the graph paper.
8. After plotting the two known a_w points, connect the points on the graph paper and record the test solution temperature on the graph.

9. To measure fluid a_{wm}, set the instrument on the CHECK mark, switch over to READ and allow the meter to stabilize. Take the meter reading and read up to the calibration line, then across to a_{wm}.

Note: *If the temperature of the fluid sample varies from calibration fluid temperature, correct as indicated on the instrument face. This corrected reading is recorded as* a_{ws} *in a decimal factor; i.e.,* $a_{ws} = 0.6$.

10. Measure shale a_{ws} as previously discussed in Oil- and Synthetic-Base Fluids.

Calibration Curve for Hygrometer

See Figure 1-4.

Example

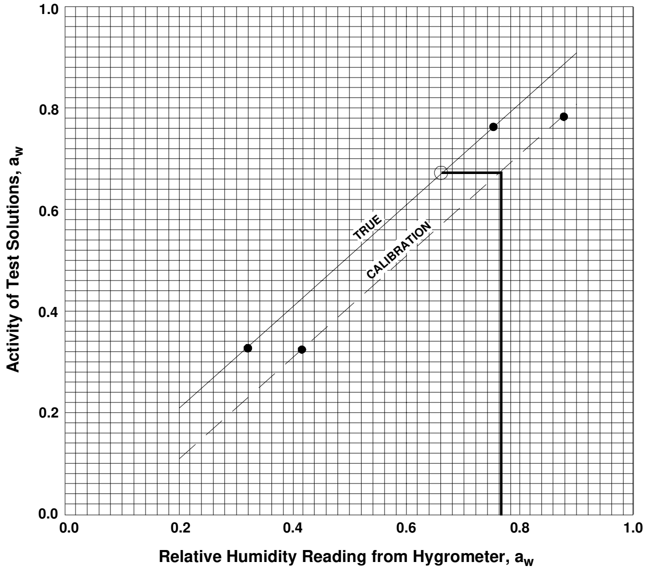
Test solution readings	$CaCl_2$ – 0.410 a_w NaCl – 0.840 a_w
Test solution temperature	86°F
Sample temperature	86°F
Sample reading (read from hygrometer)	0.765 a_w
Corrected sample reading	0.667 a_w

Procedure to Check Aniline Point

Apparatus

1. Test tube: 25 to 200 mm, graduated to 20 mL
2. Cork stopper: with holes for thermometer and stiff wire as described in #3 and #4
3. Thermometer: 0 to 200°F (–18° to 93°C)
4. Piece of stiff wire with one end bent to a loop so that it may slide up and down loosely around thermometer; the other end protruding through the second hole in the cork.
5. Chemically-pure aniline
6. Anhydrous sodium sulfate
7. Bunsen burner or other heat source

Figure 1-4 Calibration Curve for Hygrometer



For Example:

True a_w readings are plotted using $CaCl_2$ (0.320) and NaCl (0.750)
True a_w readings are represented by: ———
True a_w readings are plotted using prepared test solutions at ambient temperature.

Corrected a_w readings are represented by: — — —
Sample (fluid or cuttings) is plotted using meter reading to read up to true calibration line, then across to corrected curve.
Sample reading is represented by: ———○

Procedure

Note: *It is recommended that this test be run in the laboratory since **the aniline must be chemically pure and is very poisonous**.*

CAUTION: *Use dry apparatus. If oil appears to contain water add 5 to 10 grains of anhydrous sodium sulfate to test tube, add 20 to 30 mL of mixing oil, stopper, and shake vigorously. Let stand until top layers clear (usually about 15 minutes), pour off 10 mL of oil for aniline point test. Pour 10 mL of chemically-pure aniline into test tube. Place test tube about half submerged in a pan of hot water. Work wire loop up and down in mixture so that oil and aniline are mixed continuously.*

As mixture is heated, it will become homogeneous. Remove test tube from the bath and while still moving the wire, note the temperature at which the mixture just begins to cloud. This is the aniline point of the oil. Aniline point calculation with known values for diesel index and API gravity is

$$\text{Aniline point} = \frac{Diesel\ index \times 100}{API\ gravity} \qquad (1\text{-}43)$$

where

Diesel index = the measurement of ignition quality. This number is readily available from refinery.

Field Pilot Testing

Testing the response of a given drilling fluid to specific additives is referred to as pilot testing. The complex drilling fluid systems of today require a systematic approach to problem solving. The practice of pilot testing in the wellbore is no longer economical.

Pilot testing is not necessarily restricted to the treatment of problem fluids. It is often important to be able to predict the effectiveness of an additive, or additives, to alter fluid characteristics to meet specific downhole requirements as drilling progresses.

Recognizing that this method of testing can be utilized as a vital tool in correcting fluid problems or modifying fluid characteristics, a brief discussion of guidelines that will lead to more consistent and meaningful results should be useful.

Apparatus

A well-equipped pilot test kit should contain the following.

1. Prescription balance with weights (10 mg - 50 g)
2. Mixer with cup (115 VAC - 12 VDC)
3. Converter (115 VAC - 12 VDC)
4. Graduated cylinder (10 mL)
5. Serological pipettes (15 and 10 mL)
6. Spatula (4 in.)
7. Thermometer (0° to 220°F, metal dial)
8. Syringe (5 cm^3)
9. An assortment of dry chemicals (substitute well-site chemicals for testing when possible)
10. Roller ovens should be available on high-temp. wells.
11. High-temperature/high-pressure (HT/HP) filtration units will be required on high bottomhole temperature wells and on all jobs where oil fluids are employed.

Table 1-4 contains information for substituting small measuring spoons for a balance. The procedure for substituting measuring spoons is as follows.

Solids – Fill spoon to overflowing, tap lightly, and level with straight edge. Use the straight edge to pack the products.

Liquids – A 1 cm^3 volume is equivalent to 1 g. Use a plastic graduated syringe for liquid measurement. For greater accuracy, the actual weight of the liquid material in the syringe should be measured. This would require an instrument capable of weighing to 0.1 g. A syringe is weighed empty and then weighed with the amount of liquid to be added. The liquid weight equals the difference between the two weights.

The testing equipment, supplied by the technical representative on location, should be adequate to determine the results of the pilot test. Numerous items listed above can be obtained from local department or drug stores.

Some unique situations may arise where more sophisticated equipment, or various other chemicals, will be required to satisfactorily complete the testing. In these cases, provisions to obtain this equipment should be made as soon as possible.

See Table 1-5, Table 1-6, and Table 1-7 for other details related to pilot testing.

Sample Selections

The sample to be evaluated should be taken from the suction pit while no chemical additions are being made. A routine fluid check will confirm if it is representative of the problem that has been experienced, or if it exhibits properties consistent with previous analyses. A one gallon sample will normally be sufficient for a comprehensive evaluation. Several tests will usually be required to determine the most economical and effective treatment. It is important to use the *same fluid* when a suite of samples has to be run and the results of various additions are to be compared.

A convenient liquid volume for each “response to additive” evaluation is 350 cm^3, because 1 g/350 cm^3 is equivalent to 1 lb_m/bbl (1 bbl = 42 gal). This is normally an adequate volume to conduct the necessary measurements after sample preparation. Before removing each 350 cm^3 portion from the large sample, be sure that the sample is thoroughly mixed. Frequently, separation of the components of a fluid sample between tests will cause erroneous pilot test results.

Table 1-4 Pilot Testing Using Measuring Spoons

Product	1/4 tsp*	1/2 tsp*	1 tsp*	1 Tbsp*
Bicarbonate	1.00	1.8	3.9	12.3
Calcium Chloride (97%)	0.90	2.1	3.8	11.5
CARBO-GEL®	0.75	1.63	2.9	8.4
CARBO-VIS™	0.70	1.4	2.8	7.8
CHEMTROL® X	0.90	1.9	4.0	11.8
DESCO®	0.75	1.5	3.0	9.6
DESCO CF	0.90	1.9	4.0	10.1
DRISCOSE®	0.50	1.1	2.3	6.6
DRISPAC®	0.60	1.2	2.4	7.6
FILTREX®	0.60	1.4	2.8	8.5
Gypsum	1.30	2.3	4.9	12.8
KEM-SEAL™	0.90	1.8	3.8	10.9
LIGCO®	1.30	2.2	4.3	12.5
LIGCON®	1.10	2.0	4.0	11.6
Lime	0.60	1.3	2.4	7.7
MIL-BAR®	2.20	4.4	8.4	25.0
MIL DENSE	3.40	6.0	12.0	34.3
MILGEL®	0.90	1.9	3.6	11.1
MILSTARCH®	0.60	1.0	2.0	5.8
MIL-TEMP®	0.90	1.5	2.8	8.1
NEW-DRILL® HP	1.30	2.8	5.6	16.2
NEW-TROL™	0.60	1.5	2.8	9.1
OILFOS®	1.40	2.7	5.5	17.1
PERMA-LOSE® HT	0.50	1.2	2.4	6.8
Potassium Chloride	1.90	3.1	6.1	19.1
PROTECTOMAGIC® M	0.70	1.2	2.4	6.8
PYRO-TROL®	1.10	1.9	3.7	11.2
Salt	1.60	3.1	6.3	18.2
SALT WATER GEL®	0.70	1.5	3.0	8.8
SAPP	1.40	3.0	5.6	17.0
Soda ash	1.60	3.0	6.0	17.8
SOLTEX®	0.50	1.0	2.0	6.0
UNI-CAL®	0.70	1.4	2.7	8.2
UNI-CAL CF	0.50	1.1	2.1	6.2
XANPLEX® D	1.00	1.9	3.6	10.7

**Approximate grams of material*

Note: *DESCO, DRISPAC, DRISCOSE, and SOLTEX are registered trademarks of Drilling Specialties Co.*

Table 1-5 Pilot Testing Liquid Volumes

1 gal = 8.33 lb_m
1 lb_m ≈ 1 g
1 g = 1 cm^3
8.33 cm^3 = 8.33 g ≈ 1 gal

Table 1-6 Pilot Testing Conversion Factors (1 g/350cm^3 = 1 lb_m/bbl)

lb_m/bbl	g in 100 cm^3	g in 500 cm^3
1.0	0.286	1.428
2.0	0.571	2.857
3.0	0.857	4.286
3.5	1.000	5.000
4.0	1.143	5.714
5.0	1.428	7.140
6.0	1.714	8.571
7.0	2.000	10.000
8.0	2.286	11.428
9.0	2.571	12.856
10.0	2.857	14.286

Table 1-7 Pilot Testing Treating Solutions

1 cm^3 of 10% solution in 175 cm^3 fluid = 0.2 lb_m/bbl
1 cm^3 of 10% solution in 350 cm^3 fluid = 0.1 lb_m/bbl
1 cm^3 of 5% solution in 175 cm^3 fluid = 0.1 lb_m/bbl
1 cm^3 of 5% solution in 350 cm^3 fluid = 0.05 lb_m/bbl

Procedure

Once the sample has been selected, and the routine check has been completed, pilot testing can begin.

Several steps must be carefully observed in order to produce results that will reveal changes affected by *one* variable. The most important are as follows.

1. ***Time and Shear –*** The mixing device (especially variable-speed mixers) should be operated at the same speed for the entire suite of samples. Likewise, the mixing time should remain constant throughout the tests. The base fluid (Blank) should be subjected to the same shear and mixing time prior to testing. This will eliminate any confusion about whether the results are due to shear or treatment.

   In some cases, it may be desirable to evaluate a combination of products. When this occurs, always use another sample of base fluid. Sequential product additions to the same sample can lead to erroneous results because of extended mixing time and volume depletion.

2. ***Additives –*** All additives (chemicals, solids, or liquids) should be carefully weighed (solids) or measured (liquids) prior to incorporating them into respective fluid samples. Number the samples and record the quantity of additions in each. The additions should be made while the fluid is being stirred. This will improve homogeneity of the test samples.

   If testing requires the use of polymers, thinners, or filtration-control agents, be careful to evaluate only those that have thermal stability to perform at estimated bottomhole temperature conditions. When possible, *use additives that are stocked on location* for pilot testing.

3. ***Sample Dilution –*** If water dilution or oil dilution (if it is an oil fluid) is necessary in a weighted fluid, the sample should be restored to the original density prior to testing. This will more accurately reflect the true effects of dilution (8.3 cm^3 is the equivalent of 1 gal of dilution per bbl of fluid).

4. ***Testing –*** Measure the test sample properties as soon as possible after stirring. A time delay between mixing and testing can affect the rheological and filtration properties of the fluid. If a time delay cannot be avoided, maintain the same time lapse for each sample.

The test temperature can also affect certain properties, therefore, it should be maintained as constant as possible for all samples. Thermal heat cups should be used when testing rheological properties.

More accurate results can be obtained if the samples can be hot-rolled at 150°F for approximately three hours prior to testing, if time permits and a roller oven is available.

Application

The treatment of the circulating system, as determined by pilot testing, should be carried out in increments, especially if the treatment is to be chemical. The solubility and effectiveness of most drilling fluid additives will be increased with time and temperature.

A practical approach is to treat the system with approximately 50% to 75% of the quantity of additive, or additives, that have been determined by pilot testing. This treatment should be accomplished in one complete circulation, and the responses of the system to the treatment should be monitored. A trend in fluid property changes at this point will verify or negate the pilot test results and aid you in making a decision to either continue with the treatment or to consider another possible approach to the problem.

Packer Fluids

Typical test requirements for a packer fluid usually include long-term heat aging. The necessary laboratory equipment and time involved for these evaluations generally are not available to the Technical Service Representatives.

These tests should be referred to the Baker Hughes INTEQ Field Services Laboratory of Research and Engineering. The request should include any specifics which may be pertinent to the testing and an ample amount of time should be allowed to adequately perform the analysis.

Chapter 2

Water-Base Fluid Systems

INTEQ Drilling Systems

NEW-DRILL Fluids

A NEW-DRILL® fluid is composed of a high-molecular-weight partially-hydrolyzed polyacrylamide (PHPA) polymer contained in NEW-DRILL, NEW-DRILL HP, and NEW-DRILL PLUS. PHPA acts as a protective colloid and functions as a shale, cuttings, and well bore stabilizer. By bonding to sites on reactive shales, NEW-DRILL *inhibits* dispersion of formation solids into the fluid system. NEW-DRILL fluids are based upon low solids non-dispersed (LSND) fluid technology.

Operational Procedures

NEW-DRILL systems have been developed through experience in numerous geographic areas under various drilling conditions. Individual formulations and techniques have been developed for specific situations at different locations. The following are general guidelines for the preparation and maintenance of NEW-DRILL systems.

Methylene Blue Test (MBT)

The success of the NEW-DRILL system depends upon a low colloid philosophy. The MBT values should be maintained at 15 to 25 lb_m/bbl (42.8 to 71.3 kg/m^3). A MBT of less than 20 is ideal. MBT values above 20 lb_m/bbl (57 kg/m^3) will result in high rheological values and a requirement for dilution or a strong deflocculant.

Gel Strengths

It is common for 10-minute gels to reach 35 lb_f/100 ft^2. Drilling conditions and economics should determine the need to reduce gel strengths. Report initial, 10-minute, and 30-minute gels on all NEW-DRILL systems.

Filtrate pH

Freshwater System

Filtrate pH is normally maintained between 8.0 and 10.0. A pH of 8.0 to 9.0 is optimum for freshwater systems. Caustic soda or caustic potash additions must be made slowly to avoid a high pH at any given time. Add caustic carefully through the chemical barrel.

Seawater System

When hardness reduction is necessary for fluid-loss control, a pH of 9.5 to 10.0 should be maintained.

Range for Filtrate Hardness (Ca^{++} and Mg^{++})

Freshwater System

Maintain total hardness levels below 400 mg/L. A fluid with a concentration of 200 to 300 mg/L calcium tends to show the best stability.

Seawater System

If low rheology and fluid loss values are not necessary, seawater systems maybe run at natural pH and hardness. This is especially true when the objective of the system is to control gumbo shale.

Filter cake quality and fluid-loss control are adversely affected by high hardness. Therefore, when sand sections are drilled, the pH of the system may be increased to chemically suppress the hardness level. In seawater, the pH should be raised initially with caustic soda or potassium hydroxide to a maximum value of 9.5 to 9.7. This will precipitate most of the magnesium. Additions of soda ash and/or sodium bicarbonate should then be used to precipitate out calcium to the desired hardness level.

Fluid Loss

The filter cake quality of the NEW-DRILL® system makes fluid loss values of 10 to 20 cm^3/30 minutes sufficient in *most* situations. To determine cake compressibility, fluid loss values should be measured and reported at 100, 200, or 500 psi, and at 7½ and 30-minute intervals.

Lignosulfonate Additions

Lignosulfonate may be used in NEW-DRILL systems when excess solids cannot be mechanically removed or diluted. Avoid excessive use to ensure effective hole cleaning and to prevent mechanical erosion of the wellbore. Maintain pH values from 9.0 (freshwater) to 10.5 (seawater). This allows the lignosulfonate to function, while limiting hydroxide destabilization of shales.

Mixing Procedures

Freshwater

1. Add caustic soda and prehydrated bentonite
2. Add NEW-DRILL®
3. Add fluid-loss, deflocculants, and supplemental shale control additives
4. Add barite
5. Adjust yield point with XANPLEX® D

Seawater, Sodium & Potassium Chloride Brines

1. Prehydrate MILGEL® in drill water. Lignite or CHEMTROL X and caustic can be added, if needed.
2. Add the following to the brine.
   - Caustic for pH and hardness control
   - Prehydrated MILGEL
   - Lignite and/or CHEMTROL® X
   - Adjust salinity with sodium or potassium chloride, as needed
   - NEW-DRILL
   - Starch
   - Supplemental shale-control additives
   - Barite
   - Adjust yield point with XANPLEX D

Refer to Table 2-1 for typical NEW-DRILL formulations.

Calculations

$$\text{KCl, lb}_m\text{/bbl} \cong (\text{K}^+\text{, ppm}) \div 1496$$

$$\cong (\text{K}^+\text{, ppm}) \div 2853.9$$

$$\text{KCl, \%wt} = \frac{\text{KCl, lb}_m\text{ / bbl}}{3.5}$$

$$\text{K}^+\text{, ppm} = (\text{KCl, ppm}) \times 0.52$$

$$\text{K}^+\text{, ppm} = (\text{K}^+\text{, ppm}) \times 1.91$$

$$= \frac{\text{KCl, mg/L}}{\text{Solution density}}$$

or, where only KCl is present (new make-up only),

$$\text{K}^+\text{, ppm} = (\text{Cl}^-) \times 2.1 \times \text{\% purity}$$

Table 2-1 NEW-DRILL® Formulations

	Fresh Water	Sea Water	NaCl	KCl
Make-Up Water (% by vol.)				
Fresh water	100	50	50	100
Sea water	—	50	50	—
Electrolyte				
NaOH	*	*	*	*
NaCl, % by wt	—	—	up to 20%	—
KCl, % by wt	—	—	—	up to 15%
Viscosifier				
MILGEL®, lb$_m$/bbl	10-20	10-20**	10-20**	10-20**
XANPLEX® D, lb$_m$/bbl	—	0.1-0.5	0.1-1.0	0.1-1.0
Fluid Loss (lb$_m$/bbl)				
MIL-PAC™	0.5-1.0	0.5-1.0	0.5-2.0	0.5-2.0
MIL-PAC LV	0.5-1.0	0.5-1.0	0.5-2.0	0.5-2.0
LIGCO®	1.0-6.0	2.0-8.0***	2.0-8.0***	2.0-8.0***
BIO-LOSE™, BIO-PAQ™	—	1.5-2.0	1.5-3.0	1.5-3.0
CHEMTROL® X,†	0.5-6.0	0.5-6.0	1.0-8.0	0.5-8.0
or				
FILTREX®†	0.5-6.0	0.5-6.0	—	—
Rheology (lb$_m$/bbl)				
NEW-THIN™	0.25-1.5	—	—	—
MIL-TEMP®, ALL-TEMP™	0.25-2.0	0.25-2.0	0.25-2.0	0.25-2.0
UNI-CAL®	1.0-4.0	1.0-4.0	2.0-6.0	2.0-6.0
Shale-Control Additives				
NEW-DRILL®, lb$_m$/bbl or	0.25-3.0	0.25-3.0	0.25-4.0	0.25-4.0
NEW-DRILL HP, lb$_m$/bbl	0.25-3.0	0.25-3.0	0.25-4.0	0.25-4.0
or				
NEW-DRILL PLUS, lb$_m$/bbl	0.10-1.5	0.10-1.5	0.10-1.5	0.10-1.5
Supplemental Shale-Control Additives				
PROTECTOMAGIC®, lb$_m$/bbl or	4.0-8.0	4.0-8.0	4.0-8.0	4.0-8.0
SHALE-BOND®, lb$_m$/bbl	2.0-6.0	2.0-6.0	2.0-6.0	2.0-6.0
or				
AQUA-MAGIC™, % by vol.	1.0-3.0	1.0-3.0	1.0-3.0	1.0-3.0

*To pH = 10.5

**Prehydrated in fresh water / ***Prehydrated in pre-mix

†For high-temperature/high-pressure (HT/HP)

Determination of NEW-DRILL HP, NEW-DRILL, or NEW-DRILL PLUS in Fluid Filtrate

Apparatus

The Clapper Gas Train test involves measurement of the rate of ammonia generation while the fluid filtrate is heated in the presence of sodium hydroxide solution. The ammonia is removed from the reaction vessel with a slow air purge and is detected with a Drager tube. The approximate concentration of NEW-DRILL® is determined by measuring the time required for the Drager tube to turn blue. The procedure can be used to analyze all filtrates except those containing lignosulfonates and acrylamide-containing filtration-control additives.

1. Ungraduated hydrometer cylinders: two
    - Height – 250 mm
    - Diameter – 38 mm
2. Hot plate
3. Flowmeter
4. Air pump
5. Rubber stoppers with glass tubing: two
6. Drager tubes: two boxes, Part No. CH20501
7. Power cord
8. Stainless steel beaker: 1200 cm^3
9. Carrying case
10. Thermometer: 500°F (260°C)
11. Timer
12. Wash bottle
13. Box filter paper: Whatman No. 50 or equivalent
14. 20% (w/w) NaOH solution: 500 cm^3 bottle[1]
15. Syringe: 20 cm^3
16. Syringe: 50 to 60 cm^3
17. Graduated cylinder: 50 cm^3
18. File
19. Brush

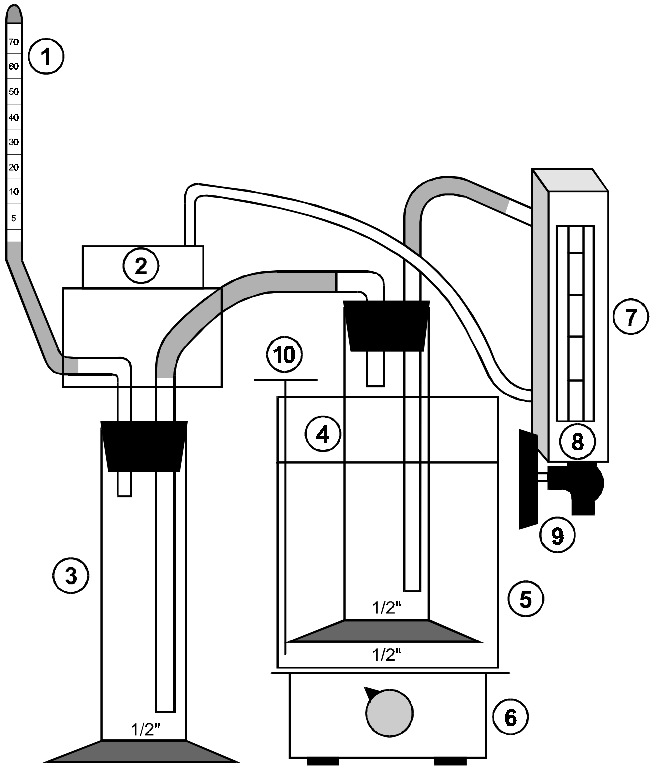
---

[1] Additional 20% (w/w) sodium hydroxide solution may be prepared by dissolving sodium hydroxide (flakes or pellets) in deionized or distilled water in the ratio of 20 g sodium hydroxide for every 80 g (80 cm^3) of water.

Procedure

1. Proper assembly of the Clapper Gas Train is illustrated in Figure 2-1.
2. Unit must be calibration to obtain accurate results.
3. Be sure that equipment is clean and dry.
4. Obtain 5 or 10 cm^3 of fluid filtrate with an API filter press (see API RP13B for description of filter press).
5. Remove reaction cylinder (inside beaker) from kit. Fill stainless steel beaker with approximately 800 cm^3 of water. Place the beaker containing the water on the hot plate. Heat water to 190° to 194°F (88° to 90°C). The temperature may be controlled with the hot plate thermostat and by the addition of water (to the water bath) from the wash bottle.
6. Break both ends of the Drager tube and insert (with numbers increasing from bottom to top) into holder and attach outlet tubing from Cylinder 3. Fill 50 cm^3 syringe with 40 cm^3 of 20% sodium hydroxide solution.
7. Inject sodium hydroxide into reaction cylinder. Add filtrate into Cylinder 4. Attach cylinder to apparatus. Turn on the air pump, set at 100 cc/min, start the timer.
8. Record time required for blue color to reach line marked "70" on the Drager tube.
9. Compare the time required for blue color to reach "70" mark with the times on the calibration chart. Report concentration of available NEW-DRILL® as lb_m/bbl of product.
10. If the test time to the "70" mark is less than 11 minutes, reduce the sample size by 50% and report the concentration of NEW-DRILL as twice that shown on the calibration chart.
11. To clean the gas train, remove the reaction cylinder and rinse well with water. The other cylinder may be attached directly to the air pump and flushed with air for several minutes. Both cylinders should be dried before reuse.

Figure 2-1 Clapper Gas Train Polymer Analysis Kit



PROPER ASSEMBLY OF CLAPPER GAS TRAIN POLYMER ANALYSIS KIT

(1) Drager Tube
(2) Air Pump
(3) Hydrometer Cylinder (moisture trap)
(4) Hydrometer Cylinder (reaction cylinder)
(5) Stainless Steel Beaker
(6) Hot Plate
(7) Flowmeter
(8) Air Flow Adjustment
(9) Air Flow Adjustment
(10) Thermometer

Calibration

The procedure is performed with an aqueous solution containing the required lb_m/bbl NEW-DRILL as per the calibration chart (see Table 2-2). The air flow should be adjusted, using the adjustment at the base of the flowmeter and the excess flow valve, so that the time required for the blue color to reach the “70” mark is 24 to 25 minutes. This will require a flow of approximately 100 cm^3/min.

Although there is some batch-to-batch variation in the Drager tubes, one calibration is sufficient for all Drager tubes having scale lengths of 51 to 56 mm. However, the unit should be recalibrated for Drager tubes having scale lengths less than 51 mm. or greater than 56 mm. When possible, use Drager tubes from only one batch to obtain the best accuracy. Batch numbers for Drager tubes are located on the outside of each box.

For any other acrylamide product, a separate calibration chart should be made.

Table 2-2 NEW-DRILL Concentration in Filtrate

Time to “70” Mark (min-sec)	NEW-DRILL® or NEW-DRILL HP Concentration (lb_m/bbl)[a] 10 cm^3 Filtrate	NEW-DRILL PLUS Concentration (lb_m/bbl)[b] 5 cm^3 Filtrate
Less than 11'	Greater than 1	0.60
11' to 13'	1.0	0.60
13'-01" to 15'-59"	0.9	0.55
16' to 19'	0.8	0.50
19'-01" to 21'-59"	0.6	0.40
22' to 27'	0.5	0.30
Greater than 30'	Less than 0.2	0.10

a. Calibrate with 0.5 lb_m/bbl NEW-DRILL solution.
b. Calibrate with 0.3 lb_m/bbl NEW-DRILL PLUS solution.

Deepwater Drilling Fluid System

Drilling in water depths ranging from 500 to greater than 7000 ft (152 m to greater than 2134 m) presents several operational challenges. One of these challenges concerns the potential for the formation of natural gas hydrates at and slightly below the mud line, in the riser pipe, and in the BOP equipment. Gas hydrates are ice-like crystalline solids formed by the reaction of gas and water at elevated pressure. They can form in aqueous systems at temperatures well above the freezing point of water. Low temperatures coupled with the pressures encountered during well-control operations in deep water, create an environment conducive to the formation of gas hydrates. These hydrates have plugged riser pipes, preventing circulation and rendered BOP equipment inoperable.

Extensive research on natural gas hydrates has shown that hydrate formation can be suppressed through the use of drilling fluids containing high salt concentrations. Various alcohols and other compounds that hydrogen bond with water are also known to suppress hydrate formation. With these factors in mind, a sodium chloride/NEW-DRILL® (salt/PHPA) fluid system containing a proprietary glycol additive has been developed. The system has been shown to have excellent hydrate suppression characteristics. Hole stability coupled with near gauge holes have been added benefits of the system. Refer to Table 2-3 for a typical deepwater drilling formulation.

Table 2-3 Deepwater Drilling Formulation

Function	Product	Concentration
Electrolyte	NaCl, % by weight NaOH	Up to 20% pH = 10.5 - 11.0
Viscosifier	MIL-GEL®, lb_m/bbl	10 - 15
Fluid Loss (lb_m/bbl)	MIL-PAC™ or MIL-PAC LV, PERMA-LOSE® or BIO-LOSE™ BIO-PAQ™ CHEMTROL® X LIGCO®	0.5 - 2.0 4.0 - 6.0 2.0 - 4.0 2.0 - 4.0 2.0 - 8.0 2.0 - 8.0
Rheology	UNI-CAL®, lb_m/bbl	2.0 - 6.0
Shale Control	NEW-DRILL®, lb_m/bbl or NEW-DRILL PLUS, lb_m/bbl	.25 - 4.0 .10 - 1.5
Defoamer	LD-8®	As needed
Shale/Gas Hydrate Inhibition	AQUA-COL™, % V/V	Up to 30% as required
Gas Hydrate Inhibition	NF-2®, % V/V	10 - 40% as required

AQUA-DRILL Glycol-Base Fluids

INTEQ's AQUA-DRILL℠ system is a glycol-base drilling fluid designed as an environmentally safe alternative to traditional oil- and synthetic-base fluids.

System Components

The system is composed the following.

1. A primary aqueous phase which may be composed of fresh water, or any of a number of brines.
    - Calcium Bromide
    - Calcium Chloride
    - Calcium Nitrate
    - Potassium Acetate
    - Potassium Chloride
    - Potassium Formate (CLEAR-DRILL™ K)
    - Sodium Acetate
    - Sodium Bromide
    - Sodium Chloride
    - Sodium Formate (CLEAR-DRILL™ N)
2. The type and concentration of the brine selected may be used to adjust the cloud point, lower the activity of the water phase, and provide additional shale stability. In addition, in deep water applications offshore, the brine phase is generally the primary agent for gas hydrate suppression.
3. One or a combination of several engineered glycols (AQUA-COL™, AQUA-COL B, AQUA-COL D, AQUA-COL S, AQUA-COL XS) selected by the desired cloud point and brine compatibility. Also, in deep water applications, the glycol phase will contribute to gas hydrate suppression.
4. Supplemental polymeric shale inhibitors (AQUA-SEAL™, NEW-DRILL® PLUS)
5. Biopolymers for rheological control (INTEQ's XANPLEX® D, Xanvis)
6. PAC and starch products (PERMA-LOSE™ HT, BIO-LOSE™, BIO-PAQ™, MILSTARCH®) for filtration control
7. Rate of penetration enhancing agents (PENETREX®)

8. Additional components to address further reduction in Pore Pressure Transmission through near-wellbore precipitation mechanisms (ALPLEX™).

System Application

The principal application for low molecular weight, water soluble glycols is the drilling of reactive shales. Well bore stability is significantly improved through the inhibition mechanisms which are thought to be multi-fold in both number and nature.

As a result of the cloud point mechanism, as filtrate with glycol in solution begins to invade the *hotter* formation, the temperature of the filtrate increases and the glycol in solution continues to come out of solution and adsorbs onto the shale matrix, thereby effectively blocking further filtrate invasion through the shale's pore network.

Further, the glycol which stays in solution in the filtrate remains a component of the filtrate as it invades shales upon drilling contact. Because it is a viscous agent, the dissolved glycol impedes further filtrate invasion through the mechanism of increased filtrate viscosity.

Another beneficial mechanism is the direct attachment of clouded glycol to the cuttings as they appear at the bit/rock face. The cuttings, heated by their recent high energy encounter with the bit, cloud the glycol from the fluid they encounter in their *hot* state, thereby making more free glycol available to adsorb to the cutting through the near-instantaneous heat transfer. Due to an attraction between the lightly anionic glycol and the positively charged sites on the clay particles within the cuttings, the free glycol is attracted to the clay and is adsorbed onto the cutting surface. This protective film of glycol remains associated with the cuttings until carried well up the wellbore, into a cooler environment, where the glycol goes back into solution, and is not discarded with the cuttings.

This significantly reduces cuttings degradation resulting in much lower dilution rates to maintain fluid properties compared to other water-base systems. Thus, waste volumes are not only reduced, but are also of an environmentally acceptable nature. Selection of the proper glycol allows brine systems to saturation to be used. See the **AQUA-DRILL℠ System Reference Manual** (Part No. 750-500-068) for a detailed discussion of glycol chemistry and inhibition qualities.

System Preparation

1. Determine or estimate the bottomhole circulating temperature. Note that the static temperature is not an appropriate value upon which to base calculations.
2. Use GLY-CAD® 2.0 to determine the proper combination of glycol and brine for this temperature. Table 2-4 is a compilation of various brine and glycol cloud points. It can be used for planning purposes in lieu of GLY-CAD. However, the final system formulation should be prepared from GLY-CAD.
3. Pretreat the water with caustic and bicarb to remove hardness.
4. Mix the viscosifier into the water to achieve proper hydration.
5. Add the amount of supplemental shale stabilizer desired.
6. Adjust the pH of the system to the range of 8.5 to 9.0, if necessary.
7. Add sufficient salt to the water to achieve the level determined in Step 2. Note that it may be desirable to add the salt prior to additions of viscosifying polymers, as they may significantly slow the wetting of the salt while mixing.
8. Mix the fluid loss control materials.
9. Add the weighting agent.
10. Add the appropriate volume of the selected cloud point glycol. The glycol volume is calculated based only upon the total liquid volume of the system.
11. Add additional rheology modifiers (viscosifiers or deflocculants) as necessary to achieve the required rheological properties.

The proper concentrations for the rheology modifiers, supplemental shale control agents, and fluid loss control agents is best determined by pilot testing. The order of addition is important for optimum fluid property development. General guidelines for fluid properties are shown in Table 2-5.

Table 2-4 Range of Glycol Cloud Points in Various Brines

Product	Brine	Salt, %	CPT, °F
AQUA-COL, 1-10% by wt.	DI Water	N/A	107 - 165
	$CaBr_2$	5 - 9	93 - 145
	$CaCl_2$	5 - 9	72 - 120
	K_2CO_3	5 - 10	41 - 116
	KCl	5 - 20	42 - 130
	$KHCO_2$	5 - 10	54 - 116
	NaCl	5 - 26	25 - 124
	$NaHCO_2$	5 - 10	58 - 123
AQUA-COL B, 1-10% by wt.	DI Water	N/A	218 - 425
	$CaBr_2$	9 - 39	172 - 225
	$CaCl_2$	5 - 37	128 - 212
	$Ca(NO_3)_2$	7 - 28	186 - 240
	KCl	5 - 20	104 - 241
	NaBr	5 - 40	112 - 255
	$NaC_2H_3O_2$	5 - 10	131 - 270
	NaCl	5 - 26	62 - 225
AQUA-COL D, 1-10% by wt.	DI Water	N/A	182 - 425
	$CaBr_2$	29 - 39	213 - 270
	$CaCl_2$	5 - 37	132 - 425
	$Ca(NO_3)_2$	7 - 28	135 - 425
	KCl	5 - 20	92 - 242
	$KHCO_2$	5 - 10	107 - 164
	NaBr	5 - 40	130 - 425
	$NaHCO_2$	5 - 10	147 - 270
	$NaC_2H_3O_2$	5 - 10	147 - 425
	NaCl	5 - 26	74 - 425
	$NaHCO_2$	25 - 40	108 - 196

Table 2-4 Range of Glycol Cloud Points in Various Brines

Product	Brine	Salt, %	CPT, °F
AQUA-COL S, 1-10% by wt.	$CaBr_2$	39 - 44	304 - 425
	$CaCl_2$	37 - 41	294 - 308
	$Ca(NO_3)_2$	21	450
	KCl	15 - 20	195 - 286
	$KHCO_2$	30 - 50	22 - 139
	NaBr	40	269 - 288
	$NaC_2H_3O_2$	20 - 30	136 - 230
	NaCl	15 - 26	146 - 262
	$NaHCO_2$	25 - 40	52 - 178
AQUA-COL XS, 1-10% by wt.	$CaBr_2$	5 - 44	412 - 450
	$CaCl_2$	28 - 41	272 - 333
	K_2CO_3	10	208
	$KHCO_2$	30 - 50	30 -140
	NaBr	40	334 - 374
	$NaC_2H_3O_2$	30 - 35	172 - 200
	NaCl	20 - 26	200 - 425
	$NaHCO_2$	30 - 40	30 - 165

Table 2-5 AQUA-DRILL Fluid Properties Guidelines

Hole Size	Yield Point lb/100 ft^2	Initial Gel lb/100 ft^2	10 Min. Gel lb/100 ft^2
17.5" / 16"	25 - 40	5 - 10	9 - 20
12.25"	18 - 25	4 - 8	7 -15
8-3/8" / 8"	10 - 15	4 - 8	7 -15

Test Procedures

Two simple and effective tests for the AQUA-COL™ product line are available.

Colorimetric Method (GLY-KIT®)

This is the standard method for the determination of AQUA-COL in drilling fluid filtrates. The AQUA-COL is extracted into dichloromethane using a blue complexing agent. The resulting blue color of the dichloromethane is compared to standard solutions and the concentration determined.

Equipment

- Eppendorf Variable Volume Pipette, 100 (µL)
- Pipette tips, 10 to 100 (µL range)
- Test Solution Vials
- Color Wheel for viewing samples and holding vials
- Box of Kemwipes

Procedure

1. Determine the appropriate volume of filtrate for the test from the GLY-KIT instructions.
2. Attach pipette tip to pipette.
    - Press the yellow control knob down to the first stop.
    - Hold the pipette vertically and immerse tip about 3 mm into the filtrate.
    - Let the yellow control knob rise slowly to fill the tip with liquid.
    - Slide the tip out of the filtrate along the wall of the container.
    - Wipe off any droplets on the outside of the tip with a towel.
3. Open the test vial and dispense the filtrate.
    - Hold the pipette tip at an angle against the inside of the vial.

- Press the yellow control knob slowly down to the first stop and wait about three seconds.
- Press the button down to the second stop to empty the tip completely.
- Hold the button down and slide the tip along the wall on the vial and remove.
- Let the yellow control knob glide back to its rest position.
- Eject the tip by pressing the tip ejector button.

4. Cap the vial and shake for 1 minute.
5. Allow vial to rest for 2 to 3 minutes while the phases separate.
6. Place vial in the top of the color wheel viewer to best match its color to one of the standard solutions. Tilt the color wheel forward and view the % by volume AQUA-COL™ in the aqueous phase on the scale which is visible through the small hole on top of the color wheel. Record.

Note: *Although the GLY-KIT® procedure remains essentially the same for all AQUA-COL types and concentrations, some variations in the amount of filtrate required for the test are necessary. Refer to the detailed instructions accompanying the GLY-KIT.*

Cloud Point Method

This method makes use of the AQUA-COL's cloud point properties. A filtrate sample is collected in a graduated cylinder or small vial and placed in a beaker of water on a heating element. The temperature is raised until the AQUA-COL™ in the filtrate *clouds out*. At this point, there will be a phase separation initially characterized by a sharp increase in turbidity, or cloudiness. If clouding does not occur at a low enough temperature, then the cloud point can be lowered by increasing the salinity of the filtrate by adding a measured quantity of the salt in use.

The cloud point temperature, the AQUA-COL type, and the salt variety and concentration can then be entered into the GLY-CAD® 2.0 program, and the concentration of the AQUA-COL can be determined via back calculation.

Cloud Point Maintenance

Under normal drilling circumstances, there is a temperature differential between the *bottomhole circulating temperature* (BHCT) and the formation temperature. To achieve the optimum performance from cloud point glycols, the cloud point of the fluid should be maintained close to, or somewhat lower than, the BHCT.

Baker Hughes INTEQ AQUA-COLs are available so that any cloud point between approximately 20°C (68°F) and 218°C (425°F) can be achieved. Higher and lower values are attainable, but are seldom necessary.

Glycols can be run in combination, however, the cloud point determination becomes difficult, as one glycol clouding out tends to mask the cloud point of the second glycol.

Generally, AQUA-COLs are effective at concentrations as low as 2% to 3%. Where possible, the AQUA-DRILL℠ system should be engineered to contain at least 3% by volume of AQUA-COL.

Logistics

In order to minimize the amount of material transported to the rig, the fluid can be shipped as a concentrated bulk liquid. Elevated concentrations of AQUA-COL, salt, and polymers in the premix are such that when the brine is diluted with drill water or seawater, all products come to the desired concentration. This process has a potential limitation. If the levels of AQUA-COL™ or salt are too high, the glycol may cloud out, thereby allowing the premix to develop separate phases. GLY-CAD® 2.0 analysis of the proposed premix concentrations, and the expected temperatures the fluid will encounter during transport, should be performed to determine if the glycol will remain in solution.

Table 2-6 lists typical fluid compositions and properties for several AQUA-DRILL℠ fluids used in the North Sea.

Table 2-6 Typical Fluid Compositions and Properties

Product Concentrations					
Well	**1**	**2**	**3**	**4**	**5**
KCL, ppb	37.60	39.58	35.52	33.83	30 - 32
MIL-PAC™ REG, ppb	0.87	1.07	0.58	1.03	–
MIL-PAC™ LV, ppb	2.01	3.91	1.00	1.10	1 - 2
NEW-DRILL® L, ppb	1.99	1.78	1.17	1.65	–
XANPLEX® D, ppb	0.31	0.47	0.49	0.80	0.75 - 1.25
AQUA-COL™, % by vol.	3.40	3.94	3.10	3.11	–
Caustic Soda, ppb	0.94	0.57	N	0.80	0.25 - 0.5
MIL-BAR®, ppb	223.90	282.30	141.89	120.0	–
AQUA-COL D, % by vol.	–	–	–	–	10
PERMA-LOSE® HT	–	–	–	–	2 - 4
Ground Dolomite	–	–	–	–	30 -60
Soda Ash	–	–	–	–	0.25 - 0.5
Typical Drilling Fluid Properties					
Fluid Weight, ppg	12.5 - 13.2	13.1	11.4	9.8 - 11.1	9.6
Plastic Viscosity, cP	30 - 35	25 - 35	20 - 25	18 - 25	15 - 20
Yield Point, lbs/100 ft^2	25 - 30	28 - 32	20 - 27	20 - 34	14 - 18
Gel Strength, lbs/100 ft^2	4-7 / 5-14	3-5 / 7-8	4-5 / 6-9	6 / 12	–
MBT, ppb	5 - 22.5	5 - 15	5 - 11.5	5 - 20	< 10
KCL, ppb	33 - 36	25 - 35	30 - 35	35	30 - 32
Chlorides, g/L	45 - 57	35 - 45	40 - 46	55	50 - 80
API Filtrate, cc	3.0 - 5.6	4.0 - 4.8	5.0 - 6.4	5.0	< 5.0
P_f / M_f, cc	0.2 / 0.6	0.4 / 1.2	0.2 / 0.4	0.3 / 1.0	–
pH	9.0 - 9.5	9.5	9.5 - 10	9.5 - 10	8.5 - 9.5

BIO-DRILL

The BIO-DRILL® fluid system contains a water insoluble polyol. The system is designed to enhance ROP by eliminating the adhesion of hydrated shale cuttings onto the face of PDC bits. The result is a system which provides an environmentally safe alternative to oil-base fluid and allows the use of a PDC bit in softer formations that have traditionally been difficult to drill with water-base fluids.

Table 2-7 BIO-DRILL Water-Base Fluid System

Features	Benefits
Preferentially wet metal surfaces with a hydrophobic coating	Improves Rate of Penetration (ROP)
Borehole stability	Prevents bit-balling
Thermally stable	Reduces torque and drag
Non-damaging to production formations	Environmentally safe

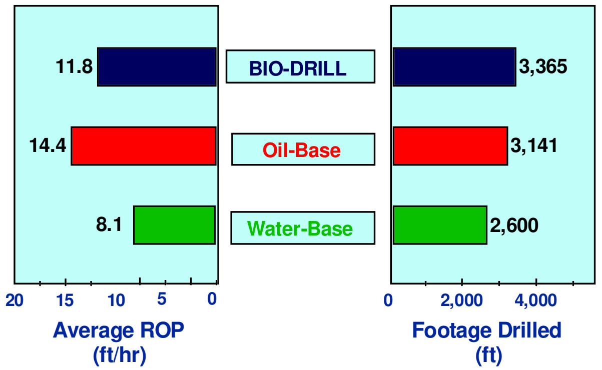
BIO-DRILL covers metal with a hydrophobic coating by displacing water from the metal's surface. This polyol coating prevents the adherence of sticky cuttings to the metal. The bonds formed by the adsorption of the polyol to the metal are not easily broken. Consequently, low concentrations of BIO-DRILL can produce dramatic improvements in penetration rate.

The BIO-DRILL system is recommended for the following conditions.

- "Sticky" shale drilling
- Operator preference for PDC bits
- High torque
- Drilling formations with historically low penetration rates with water based fluids
- Sliding problems

Figure 2-2 gives a comparison of the rates of penetration achieved with the BIO-DRILL system to both water- and oil-base alternatives.

Figure 2-2 Rate of Penetration Comparison: South Texas Wells



System Preparation

The BIO-DRILL® system is made from the products listed in Table 2-8. Alternatively, the BIO-DRILL component can be added to any other Baker Hughes INTEQ water-base fluid system, including AQUA-DRILL℠. BIO-DRILL is added through the hopper or via a chemical pump. BIO-DRILL is an insoluble polyol, has a Specific Gravity of 1.00 and a pH of 6.8 to 7.0. The effect of adding BIO-DRILL on the drilling fluid system's properties is minimal. Depending upon the amount of BIO-DRILL added, an increase in plastic viscosity may be noted.

Table 2-8 BIO-DRILL System Components

Product	Quantity
PYRO-TROL®	1 - 2 lb_m/bbl
MIL-PAC™ LV	0.5 - 1.0 lb_m/bbl
NEW-THIN™	0 - 0.75 lb_m/bbl
XANPLEX® D	to supplement viscosity
MIL-BAR®	as needed
Caustic Soda	to pH of 8.5 - 9.5
BIO-DRILL®	1% - 5%

The amount of BIO-DRILL® to be added to the system should be established by pilot testing prior to spudding. The full complement of BIO-DRILL should be added to the system prior to the expected trouble interval.

System Maintenance

The BIO-DRILL component concentration is determined by retort analysis. The BIO-DRILL will appear as an oily looking layer in the retort collection cylinder. Multiplying the correction factor of 1.5 times the volume % of the BIO-DRILL component determined by the retort gives the actual concentration of BIO-DRILL in the drilling fluid. The volume percent solids should then be corrected for the BIO-DRILL by subtracting the incremental BIO-DRILL volume % increase from the total solids volume % obtained from the retort.

Maintain the LGS concentration of the system below 5%. Ensure that the LGS concentration is below 3% prior to the initial addition of the BIO-DRILL component to the fluid.

The original water-base fluid type will continue to be the basis for identifying system problems and for deciding on corrective actions. The BIO-DRILL component will benefit the operator with ROP improvement and torque reduction as long as the concentration of BIO-DRILL® is maintained.

BIO-DRILL is immune to hardness and can tolerate a small rise in pH. Every effort should be made to maintain the drilling fluid's pH in the 8.5 to 9.5 range. BIO-DRILL has been tested and proven to be stable to 475°F. At higher temperatures, laboratory tests should be conducted to determine the optimum BIO-DRILL content.

AQUA-MAGIC

AQUA-MAGIC™ is a polyol based drilling fluid additive designed to prevent differential sticking in depleted or sub-normally pressured zones. AQUA-MAGIC is environmentally friendly, being both non-toxic and oil-free.

AQUA-MAGIC is designed to bridge depleted sands, decrease torque and to allow trouble-free logging and casing running. This is achieved through the creation of a thin, tough, filter cake under dynamic conditions. The character of the filter cake will reduce torque and drag for both drilling and running casing.

The system is recommended when the following conditions exist.

- Drilling depleted sands
- Drilling under-pressured sands
- High torque
- Low penetration rates
- Sliding problems

Table 2-9 AQUA-MAGIC Applications

Application	Description	Concentration
Drilling	To reduce torque, and as a differential sticking preventative, especially through depleted and sub-normally pressured sands	2% to 3% by volume
Running Casing	Running casing and liners through depleted and sub-normally pressured sands	10% to 15% by volume

System Preparation

The base fluid is made up in-situ or transported to the site. After adjusting the fluid properties to the program range, AQUA-MAGIC™ can then be added. AQUA-MAGIC is added through the hopper or via a chemical pump into any Baker Hughes INTEQ water-base fluid system without any further pre-treatment. AQUA-MAGIC is soluble, has a Specific Gravity of 1.06 and a pH of 7.0. The effect of adding AQUA-MAGIC on the drilling fluid system's properties is minimal.

The amount of AQUA-MAGIC to be added to the system should be established by pilot testing prior to spudding. The full complement of AQUA-MAGIC should be added to the system prior to the expected trouble interval.

The addition of AQUA-MAGIC has caused foaming in seawater-base fluids and some screening of material has been noted. Always ensure that a defoamer, such as LD-9® is available at the location.

Table 2-10 AQUA-MAGIC Application Statistics

Concentration Range, vol. %	Density Range, ppg	Depth (feet)	Hole Angle	Hole Size (inches)	Differential Pressure
1¾ - 15%	9.3 - 17.6	6000 to 17,000 TVD	0° to 55°	4¾ - 12¼	0 - 6170 psi

System Maintenance

The benefits of AQUA-MAGIC™ are best maintained by ensuring that the correct concentration is kept in the system. The best means of maintaining the concentration is by matching the AQUA-MAGIC replacement volume to the dilution rate.

The fluid to which AQUA-MAGIC is added will continue to be the basis for identifying system problems and for deciding on corrective actions. The AQUA-MAGIC will benefit the operator with torque reduction and improved filter cake quality as long as the concentration is maintained.

AQUA-MAGIC is immune to hardness and tolerates high pH. AQUA-MAGIC has been tested and proven to be stable to 250°F. The cloud point of the glycol will vary with salinity. The use of AQUA-MAGIC is not advised in HP/HT applications and with slim-hole drilling MWD tools (< 3½") since it may plug ports and internal flow channels. Laboratory testing should always be done to optimize the AQUA-MAGIC content.

ALPLEX Aluminum-Base Fluids

ALPLEX™ is a dry aluminum complex designed to control drilling problems associated with borehole instability. This product is soluble in all water-base drilling fluids provided the pH is above 10.5. Although some base exchange occurs, ALPLEX's primary function is to minimize pore pressure transmission. This ability to prevent pore pressure transmission allows the drilling fluid to maintain a differential pressure with the wellbore thus providing wellbore stability. (See **Pore Pressure Transmission** for further discussion on ALPLEX interaction with shales.)

Since ALPLEX has an alkaline pH, it requires no caustic soda for neutralization. In freshwater systems, it can be applied directly through the mixing hopper. To increase its performance in saltwater systems, presolubilization of ALPLEX is recommended.

As ALPLEX reduces clay hydration, more water becomes available which decreases the requirement for deflocculants, especially in polymer systems. Because clay solids are less hydrated, fluid rheological properties are very stable. Clays with less hydration have lower viscosity, allowing polymer-base systems to be more tolerant of contaminants.

The ALPLEX induced shale stabilization increases shale inhibition in UNI-CAL® lignosulfonate systems, as well as NEW-DRILL® polyacrylamide systems using seawater, saltwater, potassium ions, and freshwater. ALPLEX can be used to replace potassium ions which are effective in limiting hydration because of their size and the cationic exchange that takes place in the clay structure.

Environmental concerns about chloride pollution limit the use of cations from simple salts such as KCl and NaCl. Fortunately, aluminum chemistry reduces or eliminates the need for these cation additions. Extremely reactive clays, however, can be inhibited by using a combination of potassium ions from potassium acetate and ALPLEX.

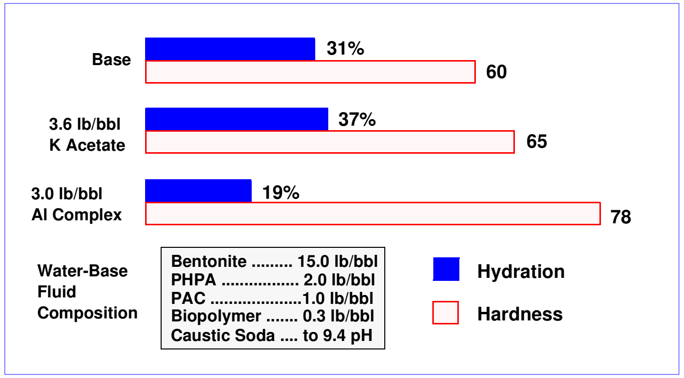


Figure 2-3 ALPLEX Economically Replaces Potassium Ions without Flocculation

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Application Guidelines

Basic Formulation

This basic formulation can be used in wells with bottomhole temperatures not exceeding 300°F. For higher BHT, special formulations may be developed.

Water	Fresh to saturated NaCl
MILGEL®, ppb	5 - 15
NEW-DRILL® HP, ppb	1 - 3
BIO-PAQ™, ppb	2 - 3
XANPLEX® D, ppb	As needed for desired yield point
ALPLEX™, ppb	1 - 6 depending on shale reactivity

Mixing Procedure

Freshwater System

ALPLEX can be added directly to the circulating system through the hopper. To achieve maximum effectiveness, the water should be treated for any possible hardness.

Seawater System

1. The seawater system should be pretreated with NaOH and Na_2CO_3 to precipitate any magnesium and calcium. The pH of seawater should reach the 10.5 level to precipitate most of the magnesium. This will increase the performance of the PHPA and eliminate the pH lowering due to magnesium.

   The ALPLEX™ should be presolubilized in fresh water at a high concentration (80 to 120 ppb) in the slug or separate pit and then fed slowly to the active system (10 bbls/hour+ depending on the total circulating time).

Note: *Do not add ALPLEX directly to untreated seawater for it will not go into solution properly.*

2. The PHPA, MIL-PAC™, or BIO-PAQ™ should be premixed in the pretreated brine water and sheared adequately to enhance the performance of the polymers and prevent any possible blinding of the shaker screens.

3. The MILGEL® should be prehydrated in fresh water to ensure good filter cake quality.
4. The PHPA can be either NEW-DRILL® HP (liquid or plus). However, to avoid any possible blinding of the shaker screens, and for better performance, the PHPA should be well sheared prior to drilling.
5. MIL-PAC™ LV (0.75 to 1.0 ppb) can be substituted for BIO-PAQ™ (2 to 3 ppb).
6. MIL-PAC R can be used in combination with XANPLEX® D to increase yield point for better hole cleaning.

Note: *Due to its strong inhibition characteristics, the initial ALPLEX treatment will depend on the amount of solids in the initial fluid. In unweighted fluid having a CEC < 10 meg/100 g and less than 2% LGS, the initial ALPLEX treatment should be about 1 ppb. The desired ALPLEX concentration in the total system should be increased as drilling progresses. This measure will prevent a sharp drop in rheological properties, especially when good hole cleaning properties are required.*

Treatment and Maintenance

Formation uptake of ALPLEX™ is generally dictated and directly proportional to the reactivity of the shale being drilled and the extent of any microfractures present. The following are maintenance guidelines for an ALPLEX system.

1. For maximum effectiveness, the fluid pH should be kept between 10.5 and 11.5. Higher treatment regimens of ALPLEX will result in higher fluid alkalinities. For extremely high treatments (> 8 lb/bbl), fluid pH may occasionally drift above 11. Addition of high concentrations of LIGCO® with ALPLEX should be avoided because it will be difficult to maintain the pH above 10. Viscosity increases caused by the addition of ALPLEX to a low pH fluid can be minimized by adjustment of the fluid pH to 10 prior to introducing ALPLEX. The pH of the fluid should be maintained above 10.0 with small ALPLEX additions.

A normal fluid pH varies between 10 and 11.5 depending on the ALPLEX™ concentration.

2. Although the ALPLEX system is solids tolerant, the low gravity solids should be maintained at less than 6%.
3. Use MIL-PAC™ R and XANPLEX® D for sweeps instead of MILGEL®.
4. In seawater or high salt ALPLEX systems, use presolubilized lignite for additional filtration control. To avoid pH drop due to additional lignite, compensate with caustic soda, using a 4:1 (lignite:caustic) ratio. If mixing in same pit, add caustic to lignite first, then add ALPLEX.
5. When the fluid system becomes depleted of ALPLEX, any or a combination of the following should happen.
   - The pH of the fluid will drop below 9.5.
   - The cuttings over the shakers will become soft and sticky. Blinding of the shaker screens may occur.
   - The fluid viscosity and rheological properties will generally increase.
   - Tight spots, excessive torque and drag, and bit balling may develop.
6. Because the consumption of ALPLEX is directly related to surface area of introduced drill solids, use of lignosulfonates may increase consumption of ALPLEX.
7. An ingredient of ALPLEX reacts with calcium and magnesium to form inert precipitates. This reaction accounts for the ability of ALPLEX fluids to tolerate cement contamination. However, when introducing ALPLEX into systems containing greater than 400 mg/L hardness, the system should be treated to reduce hardness prior to the ALPLEX addition.

Aluminum Determination by Fluoride Electrode

Equipment and Reagents

1. pH/mv Meter (Orion or instrument capable of using a fluoride electrode and having concentration mode capabilities)

2. Combination Fluoride Electrode with BNC connector – Orion 9609BN (currently supplied with Ionplus A Optimum Results filling solution)
3. Reference Electrode Filling Solution – Orion Ionplus A Optimum Results filling solution (Orion 900061) or IONALYZER reference electrode filling solution (Orion 900001)
4. **Plastic** Pipette – 0.5 mL
5. **Plastic** Beakers (2) – 150 mL
6. **Plastic** Graduated Cylinder (2) – 50 mL
7. Pipette (3 mL) or 10cc plastic syringe
8. Potassium Fluoride Solution – 0.0010 M (10 Standard)
9. Potassium Fluoride Solution – 0.010 M (100 Standard)
10. Acetic Acid/Potassium Acetate Buffer

Standards Preparation for Instrument Calibration

Note: *Graduated cylinders, beakers, and pipettes should be rinsed with distilled water and dried before each use.*

1. Place 30 mL of 0.0010 M (10 Standard) Potassium Fluoride solution into a **plastic** graduated cylinder.
2. Pour the 30 mL of 0.0010 M Potassium Fluoride solution into a **plastic** beaker.
3. Deliver by pipette or 10cc plastic syringe 3mL of the Acetic Acid/Potassium Acetate Buffer into the **plastic** beaker of 0.0010 M Potassium Fluoride solution.
4. Swirl the beaker contents to ensure proper mixing. *Allow the solution to set for 5 minutes.*
5. Place 30 mL of 0.010 M (100 Standard) Potassium Fluoride solution into a **plastic** graduated cylinder.
6. Pour the 30 mL of 0.010 M Potassium Fluoride solution into a **plastic** beaker.
7. Deliver by pipette or 10cc plastic syringe 3 mL of the Acetic Acid/Potassium Acetate Buffer into the **plastic** beaker of 0.010 M Potassium Fluoride.
8. Swirl the beaker contents to ensure proper mixing. *Allow the solution to set for 5 minutes.*

Instrument Calibration, Measuring, and Electrode Care

Electrode Preparation

The electrode is shipped without filling solution in the reference chamber. To fill from the flip-spout bottle:

1. Lift the spout to a vertical position.
2. Insert the spout into the filling hole in the outer sleeve and add a small amount of filling solution to the chamber. Tip the electrode to moisten the O-ring at the top and return electrode to a vertical position.
3. Holding the electrode by the barrel with one hand, use the thumb to push down on the electrode cap, allowing a few drops of filling solution to drain to wet the inner cone.
4. Release sleeve. If sleeve does not return to its original position immediately, check to see if the O-ring is moist enough and repeat Steps 2 through 4 until the sleeve has returned to the original position. Add filling solution up to the filling hole.
5. The probe is now ready for use.

Note: *Add filling solution each day before using electrode. The filling solution should be at least one inch above the level of sample in the beaker to ensure a proper flow rate. If the filling solution is less than one inch above the sample solution level, electrode potentials may be erratic.*

6. Fasten electrode into the appropriate jack on the meter.
7. Turn the instrument on and wait approximately one minute.
8. Calibrate the meter according to the meter’s instruction manual.

Sample Preparation for Analysis

1. Place 430 mL of 0.010 M (100 Standard) into a **plastic** graduated cylinder.
2. Transfer the 30 mL of solution to a **plastic** beaker.
3. With a **plastic** pipette, add 0.5 mL of sample (fluid filtrate) to the beaker and swirl the contents to ensure proper mixing.

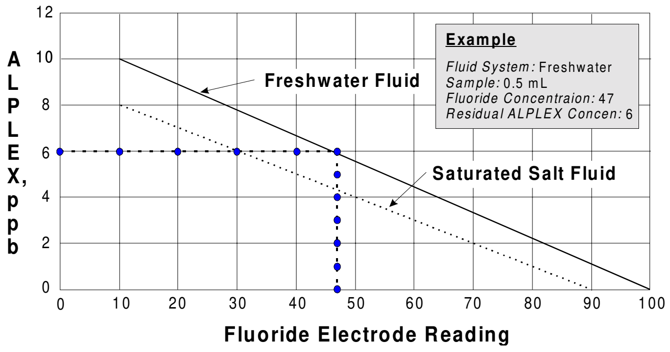
4. With a 3 mL pipette or 10cc syringe, add 3 mL of Acetic Acid/Potassium Acetate Buffer to the beaker.
5. Swirl the solution to ensure proper mixing. *Allow the solution to set for 5 minutes* prior to measurement.
6. Repeat Steps 1 through 5 for each sample.

Sample Analysis

1. Rinse the electrode with distilled water.
2. Blot probe dry. *Do not wipe dry.*
3. Prepare samples as previously described above. Place the probe in the sample and record sample readings after one minute.
4. Check calibration every 4 hours by analyzing the 100 Standard. Recalibrate if the standard differs by more than ± 3.
5. Rinse probe with distilled water and blot dry between tests.

Note: *Should the concentration readings be greater than 100, the buffer may have been forgotten!*

Figure 2-4 Fluoride Electrode Correlation Chart



Note: *Saturated salt curve should be used when NaCl concentration > 18%.*

PYRO-DRILL High-Temperature Fluid

The PYRO-DRILL^{SM} system is a flexible water-base drilling fluid that is used when temperature and/or contaminants make conventional water-base systems unstable or uneconomical. An unstable drilling fluid can result in problems such as loss of circulation, stuck pipe, and wellbore instability.

PYRO-DRILL is designed to be thermally stable and resistant to contaminants. It has been used in geothermal wells with bottom hole temperatures in excess of 600°F. Weighted fresh and salt water fluids have been used at temperatures approaching 500°F.

PYRO-DRILL^{SM} fluids have been prepared in brines with magnesium concentrations exceeding 30,000 mg/L.

Table 2-11, Table 2-12, and Table 2-13 give typical PYRO-DRILL formulations for fluids prepared with various salinity water.

Table 2-11 PYRO-DRILL Freshwater Formulation

Product (lb/bbl)	Density, lb/gal.			
	10 - 12	12 - 14	14 - 16	16 -18
MILGEL®	10 - 20	7.0 - 15	5.0 - 15	5.0 - 10
Caustic Soda	.25 - .50	.25 - .50	.50 - .75	.50 - .75
MIL-TEMP®, ALL-TEMP™	.25 - .50	.50 - .75	.75 - 1.5	1.0 - 2.0
CHEMTROL® X	1.0 - 5.0	1.0 - 5.0	3.0 - 8.0	4.0 - 10
PYRO-TROL®	.25 - 2.0	0.5 - 1.0	1.0 - 2.0	1.0 - 2.0
KEM-SEAL™	0.5 - 2.0	0.5 - 2.0	0.5 - 2.0	0.5 - 2.0
Properties				
PV, cP	10 - 25	15 - 30	15 - 30	20 - 45
YP, $lb_f/100\ ft^2$	10 - 15	10 - 15	10 -15	10 - 15
HT/HP, cc/30 min.	10 - 25	10 - 25	10 - 25	10 - 25

Table 2-12 PYRO-DRILL Seawater and Light Brine Formulation

Product (lb/bbl)	Density, lb/gal.			
	10 - 12	12 - 14	14 - 16	16 -18
MILGEL	10 - 20	7.0 - 15	5.0 - 15	5.0 - 10
Caustic Soda	.25 - .50	.25 - .50	.50 - .75	.50 - .75
MIL-TEMP, ALL-TEMP	.25 - .50	.50 - .75	.75 - 1.5	1.0 - 2.0
CHEMTROL X	1.0 - 5.0	1.0 - 5.0	3.0 - 8.0	4.0 - 10
PYRO-TROL	.25 - 2.0	0.5 - 2.0	1.0 - 2.0	1.0 - 2.0
KEM-SEAL	0.5 - 2.0	0.5 - 2.0	0.5 - 2.0	0.5 - 2.0
Properties				
Plastic Viscosity, cP	10 - 25	15 - 30	15 - 30	20 - 45
Yield Point, $lb_f/100\ ft^2$	10 - 15	10 - 15	10 -15	10 - 15
HT/HP, cc/30 min.	10 - 25	10 - 25	10 - 25	10 - 25

Table 2-13 PYRO-DRILL Saltwater Formulation

Product (lb/bbl)	Density, lb/gal.			
	10 - 12	12 - 14	14 - 16	16 -18
MILGEL®	10 - 20	7.0 - 15	5.0 - 15	5.0 - 10
Caustic Soda	.25 - .50	.25 - .50	.50 - .75	.50 - .75
MIL-TEMP®, ALL-TEMP™	.25 - .50	.50 - .75	.75 - 1.5	1.0 - 2.0
CHEMTROL® X	1.0 - 5.0	1.0 - 5.0	3.0 - 5.0	4.0 - 6
PYRO-TROL®	.25 - 2.0	0.5 - 2.0	1.0 - 2.0	1.0 - 2.0
POLY-DRILL®	5.0 - 10	5.0 - 10	5.0 - 10	5.0 - 10
KEM-SEAL™	0.5 - 2.0	0.5 - 2.0	0.5 - 2.0	0.5 - 2.0
Properties				
Plastic Viscosity, cP	10 - 25	15 - 30	15 - 30	20 - 45
Yield Point, $lb_f/100\ ft^2$	10 - 15	10 - 15	10 -15	10 - 15
HT/HP, cc/30 min.	10 - 25	10 - 25	10 - 25	10 - 25

System Preparation

1. For all brine systems, prehydrate the MIL-GEL in fresh water before addition to the brine. The minimum prehydration time will be dependent on the mixing equipment available. With a standard hopper, a minimum of 6 hours is recommended.
2. For salinity greater than 50,000 mg/L, presolubilization of the CHEMTROL X in high pH fresh water is recommended.
3. Mix the components in the order indicated in the tables.
4. All of the components are mixed through the hopper. Each of the polymer components (MIL-TEMP®, ALL-TEMP™, PYRO-TROL®, POLY-DRILL® and KEM-SEAL™) should be added slowly to ensure uniform distribution throughout the fluid and to ensure complete dispersion and effectiveness of the materials.
5. The pH of all fluids containing PYRO-TROL should be maintained below 10.5. At higher pH, alkaline hydrolysis of the PYRO-TROL will reduce its effectiveness in the system.

System Maintenance and Treatment

Maintenance and treatment of the system are indicated by the results of heat aging pilot tests under downhole conditions. After either static or dynamic aging at the expected bottomhole static temperature, the viscosity and fluid loss of the system should remain within the range established on the tables. If they are not, the system is treated with a premix that consists of the fully formulated base PYRO-DRILL℠ fluid. Because the system is a balanced system, maintaining the proper ratio of components in the system is a key to rheological stability.

Guidelines

1. Always treat with a fully formulated premix. Pilot test at the anticipated bottomhole static temperature to establish the proper treatment level.
2. Monitor the low gravity solids content of the fluid carefully. Suggested levels for various temperatures are shown in Table 2-14.

3. If severe carbonate contamination is encountered, pilot test with lime, gyp and caustic to establish the appropriate treatment program.

Table 2-14 Suggested Low Gravity Solids Content for PYRO-DRILL Fluids

Temperature, °F	Low Gravity Solids, Volume %
To 300	6
300 - 350	4
> 350	3

Specialty Fluid Systems

Silicate-Base Systems

History

Drilling fluids based on soluble silicates were first used in the 1930s for the control of *heaving shale* (shales that slough into the wellbore in sufficient quantities to interfere with the drilling operation). The first sodium silicate-base fluids contained high concentrations of silicates (20% to 50% by volume) and were used successfully to drill more than 100 wells in the U.S. Gulf Coast area. The system did provide shale stabilization, but the system's rheology was extremely difficult to control. It was replaced in the early 1940s by lime-quebracho fluids which provided much easier to control rheology.

Silicate-base fluids were re-introduced in the late 1960s by Darley who had found that most shales could be stabilized by the use of more dilute solutions (typically 5% to 10% by volume) of sodium or potassium silicate, the latter appearing to be the more effective. Addition of salts (e.g., KCl, NaCl) contributed significantly to the stability of the shales. This additional stabilizing effect was caused by shale dehydration through an osmotic gradient generated by the solutes. Three wells were drilled using the formulations suggested by Darley.

Recently, pore pressure transmission (PPT) investigations have resulted in a strong renewed interest in silicate drilling fluids. For additional information on PPT, refer to the **Borehole Problems** section of this chapter.

Structure of Silicate Solutions

Commercially available solutions of sodium or potassium silicate can be divided into two fractions.

1. Dissolved ions, e.g., sodium or potassium cations, hydroxide ions and silicate ions (SiO_4^{4-})
2. A colloidal fraction

In a concentrated sodium silicate solution, up to 75% of the silica is present in the polymerized or colloidal form. The basic building block of the silica polymers is monosilicic acid $Si(OH_4)$. It is an unstable compound and polymerizes by sharing OH^- groups between Si atoms, resulting in the formation of siloxane (Si-O-Si) bonds and the elimination of water as shown in the following equation.

$$2Si(OH)_4 \rightarrow (HO)_3 - Si - O - Si - (OH)_3 + H_2O$$

The polymeric species are not of uniform size and may be linear or cyclic. Polysilicate species with up to 12 Si atoms have been identified.

Mechanism for Wellbore Stabilization

Drilled shales require an effective radial support stress for stability. This is provided by fluid overbalance. The overbalance drives fluid filtrate and fluid pressure into the shales causing a number of destabilizing effects. The most profound of those is near wellbore pore pressure elevation (pore pressure transmission) which effectively negates the fluids's pressure support. When this occurs, the in-situ stresses can overcome the shale strength, causing plastic deformation and failure of the shale.

Improving the shale stabilizing characteristics of water-base fluids involves reducing the filtrate flow into shales. There are four possible mechanisms for reducing this flow.

1. Increasing the filtrate viscosity
2. Reducing the shale permeability

3. Balancing the flow of fluid filtrate into the shale by a back flow of pore water driven by osmotic pressure
4. A combination of all three mechanisms

Shale/fluid interfaces may behave as a membrane. The membrane is *semi-permeable* if it does not allow solute ions to pass through, but allows water molecules through. This preferential water flow is referred to as *osmosis*. This term is also used for a preferential movement or flow of water across a shale/fluid interface. Water will always flow across this membrane to equalize activity. The membrane's ability to transmit water can be decreased by additives that block the pore throats.

Silicate fluids stabilize shales by a combination of mechanisms. Silicate structures (at pH of 11 to 12.5) are small enough to enter shale pores by hydraulic flow or by diffusion. On entering the shale pores, the following would be expected.

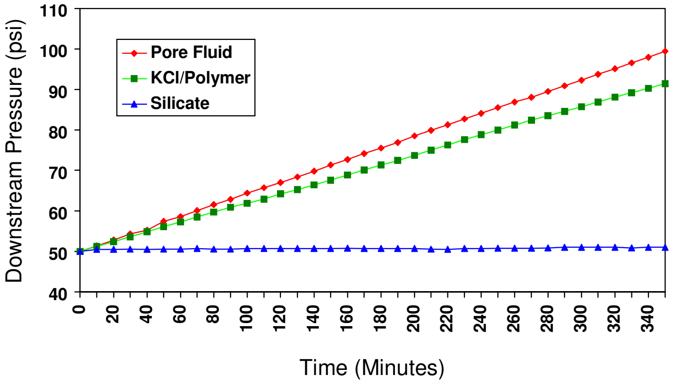
- Pore fluid pH is typically close to neutral (pH~7). When the silicates are diluted and the pH drops, the silicates will gel.
- Pore water normally contains divalent cations (e.g., Ca^{2+} and Mg^{2+}) that will rapidly induce silicate precipitation.

The gelled and/or precipitated silicates now stabilize the shales by:

- providing a physical barrier that prevents further fluid filtrate invasion and pressure penetration. Thus, the wellbore and shale formation are effectively pressure isolated. The gelation/precipitation process occurs very rapidly and is completed before significant fluid loss and pressure invasion occurs;
- enhancing the efficiency of the osmotic membrane. To prevent water flow from the fluid to the shale, the activity of the silicate drilling fluid should at least balance the shale activity.

Figure 2-5 illustrates how a silicate fluid stopped pore pressure transmission (PPT) in a shale, while a KCl/polymer fluid had little effect.

Figure 2-5 Silicate Drilling Fluid PPT Results Comparison



Applications

Shales

Silicate drilling fluids are most suitable for drilling highly dispersive shales. They may prove to provide even more stability than oil- and synthetic-base fluids. The primary protective mechanism is the generation of a film that reduces filtrate and pressure invasion between shale particles.

Microfractured Shales and Chalks

Shales which contain small fractures are rapidly destabilized by drilling fluids that invade the cracks and elevate the fluid pressure in them. Soluble silicates have the ability to fill small cracks and seal them. The mechanism is again rapid gelation and precipitation of silicate compounds when the filtrate encounters the neutral pore fluid containing polyvalent ions in the microfractures.

It has been reported that cracks up to 0.5 mm in diameter have been *healed* in the laboratory by silicate fluids. The minimum SiO_2 concentration for crack-sealing was found to be 10,000 mg/L.

Fractured chalks can be sealed by the silicate system in the same manner as fractured shales. Field reports have indicated that lost circulation in chalks has quickly self-sealed without any requirements for additional LCM.

Chalks

Some chalks ($CaCO_3$) are soft and easily dispersible. They tend to wash out and rapidly disperse in the drilling fluid necessitating high dilution rates. Silicates prevent the cuttings dispersion and wellbore wash-outs normally experienced when drilling soft chalk with water-base fluids. This is accomplished by the reaction of the silicate with the Ca^{2+} ions present on the chalk surfaces.

Limitations

Temperature

A fluid system stable to 225°F (107°C) has been developed. Work is underway to extend this to 250°F (121°C). Fluid system stability is currently limited by the stability of the polymers used for rheology and fluid loss control in the high pH environment of the system.

Density

The maximum density fluid successfully formulated in the laboratory is 15 lb/gal. (1.8 S.G.). Silicate fluids to 18 lb/gal have been reported by external sources.

Formation Damage

Significant permeability reduction has been seen in laboratory core flow studies. Until the damage mechanisms are better understood, producing formations should not be exposed to fluids containing silicate. This may be accomplished by allowing the silicate to deplete before penetrating the producing formation or by changing to a **PERF***Flow* drill-in fluid. The extent of formation damage and the possibilities for clean-up, stimulation, or bypassing the damage are being investigated.

Formulations and Fluid Properties

Three typical silicate fluid formulations are shown in Table 2-15. Formulation #1 and #2 were made with fresh water, #3 with sea water. Higher concentrations of caustic soda and soda ash are needed to precipitate divalent ions in sea water formulations.

Table 2-15 Typical Silicate Fluid Formulations and Properties

Formulation	#1	#2	#3
Fresh Water, bbl/bbl	0.64	0.74	—
Sea Water, bbl/bbl	—	—	0.78
KCl, lb/bbl	27.03	31.10	35.71
Soda Ash, lb/bbl	0.10	0.10	0.50
Caustic Soda, lb/bbl	0.20	0.20	1.60
Sodium Silicate, bbl/bbl	0.09	0.11	0.60
XANPLEX® D, lb/bbl	0.40	0.75	0.75
MIL-PAC™ LV, lb/bbl	5.00	5.00	5.00
MIL-BAR®, lb/bbl	334.7	163.7	157.8
NOXYGEN™, lb/bbl	1 - 2	1 - 2	1 - 2
Properties	**#1**	**#2**	**#3**
Fluid Density, lb/gal (S.G.)	15 (1.8)	12.1 (1.456)	12.1 (1.456)
Plastic Viscosity, cP	alap	alap	alap
Yield Point, lb/100 ft^2	18 - 22	24 - 28	24 - 28
A.P.I. Fluid Loss, cc/30 min	< 7	< 7	< 7
pH	11.5-12.5	11.5-12.5	11.0-12.0
Silicate Content (as SiO_2), g/L	50	50	30
KCl, ppb	35	35	40

The three formulations above were developed using a formulation that runs on MS Excel® 5.0. The file is available through ***InSource*** as *SILCOM.xls.* Additional information on silicate drilling fluids can be found in the Silicate Manual also accessible through ***InSource***.

Carbonate Systems

INTEQ has pioneered the development of potassium carbonate-base fluids for use in particular drilling situations. The brine phase allows densities of up to 13 lbs/gal (1.56 S.G.) to be achieved without the addition of non-soluble weighting materials. This feature makes the fluids particularly suitable for slim hole and coiled tubing drilling and as a base for drill-in fluids. They are also used in environmentally sensitive areas where the potassium ion is needed for shale control and the chloride ion from potassium chloride is considered environmentally unacceptable. The density of any of the fluids can be further increased by adding barite, calcium carbonate or ground dolomite. The fluids are prepared and maintained with common oil field additives.

Because potassium carbonate is an alkaline salt, fluids prepared from it will have considerably different properties than fluids prepared from other salts. Treatment of these fluids for common contaminants will be somewhat different. The following sections provide explanations of these differences.

Fluid Alkalinity

Potassium Carbonate is a weak base. The pH of the brine can reach 13.5 in a saturated solution. However, a normal pH in a fluid prepared from seawater is 10.2 to 10.8. Drilling cement may cause an increase in pH to over 12.5. Under these conditions, filtration and viscosity can be affected. Cement contamination should be treated with citric acid to reduce the pH. If large amounts of cement are to be drilled, then pre-treatment is advised.

The P_m is sometimes used to calculate excess lime content in drilling fluids. The carbonate fluids have a naturally high P_m that is a result of the alkaline nature of the salt. Consequently, the P_m cannot be used to determine the excess lime or cement content of a carbonate fluid.

Filtrate Alkalinity

The M_f / P_f method is quite satisfactory for these systems. The standard P1/P2 method will work if the concentration of barium chloride solution is doubled due to the high concentration of carbonate ions in these systems.

The P_f and M_f are best determined with a pH meter. The equivalence point for the formation of bicarbonate occurs at pH 8.3, the P_f. Further titration with acid results in the formation of carbonic at a pH of 3.7, the M_f value.

$$CO_3^{2-} + H^+ \Leftrightarrow HCO_3^- + H^+ \Leftrightarrow H_2CO_3$$

The concentrations of carbonate and bicarbonate ion can then be determined with the following equations. Unless there is an influx of an acid gas, the M_f should almost always be higher than twice the P_f. Therefore the carbonate ion concentration is given by $1200 \times P_f$ and the bicarbonate ion by $1220 (M_f - 2 \times P_f)$, both in mg/L.

Typical examples in a fresh water potassium carbonate system would be a P_f of 12 and an M_f of 26 for a concentration of 15 lb/bbl (42 kg/m^3) of potassium carbonate. In a new make up, the P_f may equal the M_f as only carbonate ions will exist in solution.

The hydroxide ion content can be calculated using the equation $17{,}000 \times 10^{pH-14}$. This will be an overestimate. A normal carbonate pH will not exceed 11.7. If this pH is due to hydroxyl ions alone, it represents an equivalent of 85 mg/L of hydroxyl ions. The 85 can be deducted from the value obtained above to give a more accurate estimate.

Example: For drilling cement with a pH of 12.9, the Hydroxyl content is

$$17{,}000/10^{1.1} = (17{,}000 \div 12.58) - 85 = 1266 \text{ mg/L.}$$

Calcium Determination.

Since a large excess of carbonate ions are in solution, calcium ions will be rapidly precipitated out of solution. Some magnesium ions will also be precipitated. The amount depends upon the concentration of the carbonate and hydroxyl ions. If the standard hardness test is run while drilling, erroneously high values for hardness will be obtained due to unidentified interferences in the titration. This can also be the case when drilling cement. Since a carbonate fluid is already a highly flocculated system, the addition of total hardness to the system has very minor effects on the fluid's performance and the total hardness titration has little relevance in these systems.

Chloride Determination.

In seawater or salt treated systems, the end point of the titration can be improved by adding 1 mL of potassium chromate indicator to each milliliter of filtrate used. This results in better endpoint reproducibility. No chloride titration problems have been identified in freshwater systems.

Potassium Determination.

The API centrifuge method is known to be inaccurate at potassium salt concentrations below 2% by weight and above 7%. Higher concentrations can be determined by dilution, but some potassium carbonate fluids may have potassium levels at the lower limit of this test's sensitivity. For these fluids, either an ion selective electrode or the STPB method can be used. See **Miscellaneous Testing Procedures** in Chapter 1 for the STPB and centrifuge methods.

Smectite Clays and Carbonate Contamination

Those familiar with water-base fluids will be aware of the problems of *carbonate and bicarbonate* contamination. These "problems" stem from the fact that most water-base drilling fluids contain hydrated clay solids and commercial bentonite. The effect of both carbonate and bicarbonate ions on hydrated bentonite clays is well documented and produces a significant increase in gel strengths and yield point.

These problems were largely overcome by using a polymer formulation (AQUA-SEAL™) specifically designed for use in potassium carbonate fluids. As a result, large quantities of reactive clay solids can be incorporated into the system without large increases in rheology.

It has been found from experience that freshwater clay based top hole fluids can be converted to potassium carbonate fluids by the addition of potassium carbonate and AQUA-SEAL. However, as the MBT rises, a rise in the viscosity, yield point, and gel strengths of the fluid will be seen. At some point, either a major dilution or the addition of AQUA-COL™ is required. A concentration of only 1% to 2% by volume of AQUA-COL is sufficient to deflocculate the system and restore good fluid properties.

Table 2-16 contains typical formulations and properties for laboratory prepared fluids. Table 2-17 gives typical field fluid properties. A potassium carbonate brine formulation table can be found in the *Salt Tables* section of Chapter 5.

Table 2-16 Typical Freshwater Formulations and Properties

	Density		
Component, lb/bbl	**9 lb/gal**	**11.4 lb/gal**	**13.5 lb/gal**
Potassium Carbonate	15.0	15.0	15.0
AQUA-SEAL™	2.25	2.50	2.75
XANPLEX® D	2.0	1.0	0.6
Barite	—	115.0	225.0
OCMA Clay Solids	—	35.0	35.0
Ground Shale Solids	—	25.0	25.0
	Density		
Property	**9 lb/gal**	**11.4 lb/gal**	**13.5 lb/gal**
Plastic Viscosity, cP	9	15	39
Yield Point, lb/100 ft^2	18	25	18
Gels, lb/100 ft^2	7 / 12	7 / 11	6 / 12
API Filtrate, cc/30 min	12.4	8.5	8.0
pH	10.0	9.4	9.4
P_m	8.0	7.5	7.2
P_f	8.2	8.6	11.1
M_f	23.7	24.2	29.6

Table 2-17 Typical Field Fluid Properties

Property	Seawater Fluid	Freshwater Fluid
Density, lb/gal	10.5	8.7 - 11.7
Plastic Viscosity, cP	18 - 27	15 - 35
Yield Point, lb/100 ft^2	20 - 54	14 - 25
Initial Gel, lb/100 ft^2	5 - 6	3 - 7
10-Min Gel, lb/100 ft^2	10 - 30	5 - 10
API Filtrate, cc/30 min	3.2 - 4.7	5 - 10
Cake, $^1/_{32}$ inch	$^1/_{32}$	$^1/_{32}$
pH	10 - 10.5	11 - 11.8
P_m	20 - 24	8 - 12
P_f	17 - 25	8 - 12
M_f	34 - 50	17 - 27
Chlorides, mg/L	22,000 - 28,000	1500 - 2500

Drill-In Fluid Systems

The PERF*FLOW* System

PERF*FLOW*® fluids were designed to be used as drill-in fluids. A drill-in fluid possesses the properties of a good drilling fluid and provides the necessary attributes of a completion fluid. In this respect, a **PERF***FLOW* fluid should be the only fluid the producing formation sees during the final drilling operation.

The **PERF***FLOW* system is based upon a bridging technique that positively controls leak-off of the fluid into the producing formation and provides a bridging zone (filtercake) that can be easily and effectively removed by the produced fluid. The **PERF***FLOW* system provides effective leak-off control over a wide range of formation permeabilities. Depending on the type of completion programmed for the well, no breakers or fluids to dissolve the bridging solids are required. Removal of the filter cake from the formation face is accomplished by flowing the well.

PERF*FLOW*'s fluid loss control mechanism is the direct result of the mechanical bridging of properly sized calcium carbonate particles on pore throat openings. The graph in Figure 2-6 illustrates the particle size distribution of the graded calcium carbonate used in **PERF***FLOW*. Note that a broad particle size distribution is used to bridge a wide range of pore sizes.

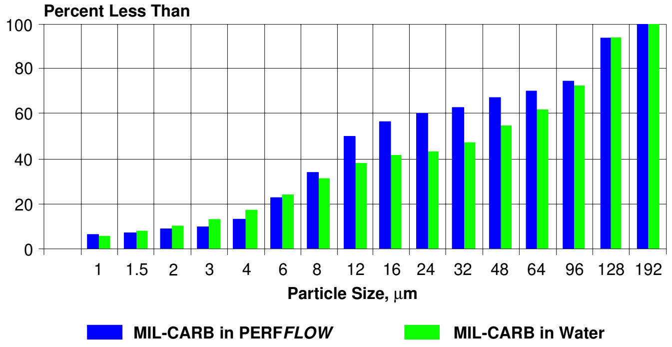


Figure 2-6 Particle Size Distribution (PSD) of the Graded Calcium Carbonate Used in PERF*FLOW*

System Application

One of three products is used to prepare a **PERF***FLOW*® fluid. W-306™ and **PERF***FLOW* DIF are used in preparing **PERF***FLOW* fluids utilizing potassium chloride, sodium chloride, calcium chloride, calcium bromide, zinc bromide, formate brines or mixtures of these brines.

PERF*FLOW* 100 is specifically designed for use where the reservoir temperature is expected to be near or below 100°F and acid will be used to stimulate the reservoir. As a result of the temperature, it is normally only used in low density brine systems (sodium, potassium, and calcium chloride).

PERF*FLOW* DIF and **PERF***FLOW* 100 are powdered products that contain all of the polymers and bridging agents necessary for the selected brine system. W-306™ is a liquid suspension of the polymers. The addition of 2% to 4% potassium chloride to all low density brines as a clay stabilization agent is recommended.

MIL-CARB™ is the bridging material used with W-306 and as a density adjustment material. Fluid density is primarily determined by the brine phase.

Standard System Formulation

LOW-DENSITY **PERF***FLOW* FLUIDS (9.2 to 10.5 ppg)

1. *Preferred Barrel Formulation*
    - 0.94 bbl of brine (including 2% to 4% KCl)
    - 1 **PERF***FLOW* DIF or 100 (55 lb/25 kg bag)
    - 1 gal/100 bbls X-CIDE® 102
2. *Optional Barrel Formulation*
    - 0.89 bbl brine (containing 2% to 4% added KCl)
    - 2 gallons W-306 (to YP ≅ 20)
    - 1 MIL-CARB (50 lb bag)
    - 1 gal/100 bbls X-CIDE 102

HIGH-DENSITY **PERF***FLOW* FLUIDS (> 10.5 ppg)

1. *Preferred Barrel Formulation*
    - 0.94 bbl of brine (no KCl)
    - 1 **PERF***FLOW*® DIF (55 lb/25 kg bag) YP ≅ 20
    - 2 to 3 ppb magnesium oxide to buffer pH ≅ 8.0

- 1 gal/100 bbls X-CIDE® 102

2. *Optional Barrel Formulation*
    - 0.95 bbl brine
    - 2 gallons W-306™ (to YP ≅ 20)
    - 1 50-lb bag MIL-CARB™
    - 1 gal/100 bbls X-CIDE® 102

Table 2-18 PERF*FLOW* Applications

Product	FLC Pills & Inside Screen Leak-off Control		FLCM after Perforation Prepacking		Coring Fluid		Drill-In Fluid		Under Reaming Fluid		Gas Well Killing Fluid *	
	≤10 ppg	>10 ppg	≤10 ppg	>10 ppg	≤10 ppg	>10 ppg	≤10 ppg	>10 ppg	≤10 ppg	>10 ppg	≤10 ppg	>10 ppg
W-306	×	×	×	×	×	×	×	×	×	×	×	×
PERF*FLOW* DIF	×	×	×	×	×	×	×	×	×	×	×	×
PERF*FLOW* 100 **	×	×	×	×	×	×	×	×	×	×	×	×

Note: *For other applications or variations to the normal mixing procedures, contact BHI Technical Services*

** Application to be discussed with Technical Services before implementation.*

*** **PERF**FLOW® 100 is recommended for use in monovalent brines and $CaCl_2$ up to 10.5 ppg.*

General Engineering Guides

Drilling fluids for vertical wells are often chosen primarily for their ability to stabilize or control the formation surrounding the reservoir. By modifying the fluid properties and dynamics, these same fluids, in many cases, have been used to drill horizontally. The potentially severe borehole problems intrinsic with horizontal drilling can be minimized dramatically by selecting a non-damaging drilling fluid system possessing optimum hole-cleaning and lubrication properties.

The drill-in fluid should be designed to minimize damage to the reservoir. If the proposed drill-in fluid design conflicts with fluid designs uphole, then a change in the fluid program may be warranted. The carrying capacity, inhibition, and lubricity of the fluid should suit the formations drilled and the prospective well profile.

It is important to devote particular attention to the cleaning, lubrication, and pay zone protection capabilities of the fluid system. For gravel packed completions, pay zone protection is extremely important. Damage to the formation will inhibit perforation filling and reduce well productivity. It is extremely important to obtain a clean interface between the gravel pack sand and the formation sand.

As with vertical wells, deciding which fluid system, or combination of systems, to use in a horizontal application depends upon the geology of the prospect, historical successes and failures, environmental constraints, and the experience of the fluid company and operator.

Even though a **PERF***FLOW*® fluid can be formulated to handle most hole conditions during the drilling operation, it may be more economical and effective to use conventional fluids such as oil-base fluids, PHPA systems, or simple bentonite-base fluids for most of the drilling operation. When to introduce the **PERF***FLOW* fluid becomes a judgement call on the part of the drilling and production engineers. The following guidelines and comments are provided to assist in making this decision.

Underreaming Operation

- *Where a cased hole exists to the top of the pay zone and it is desired to drill and underream for an open-hole completion.*

PERF*FLOW*® can be introduced to drill the pilot hole but *must* be used before starting the underreaming operation so that the final exposed producing formation sees only the drill-in fluid. In most cases, it may be best to change to the drill-in fluid while in the casing to avoid delay once the drilling operation has started. Displacement would also be more efficient in the cased hole, and exposure of the formation to two different fluids would be avoided.

- *Where an old perforated cased hole exists through the pay zone and it is desired to cut a section through the pay zone and to underream.*

The rheology and hole cleaning capacity of the **PERF***FLOW* system can be adjusted (if required) to effectively carry steel cuttings out of the hole. In a milling operation, it may be more economical to utilize a fluid specifically designed for milling or a modified version of the existing fluid. Change to the **PERF***FLOW* system before initiating the underreaming operation.

Drilling and Completing Horizontal Section

The **PERF***FLOW* fluid can be used to cut a window and to drill the build section of the horizontal well. If the existing fluid is deemed satisfactory for the milling operation and will effectively stabilize the formation to be immediately drilled, then it may be more economical to use that fluid. Where the existing fluid will require extensive treatment or a complete change-out, then consideration should be given to using the **PERF***FLOW* fluid for this purpose.

Extended Drilling Required from Casing Point or Kick-Off Point

Since **PERF***FLOW* is used as a drill-in fluid, it does not contain any highly active drill solids such as clays. Therefore, using a **PERF***FLOW* system to drill several thousand feet of hole prior to encountering the producing formation would not be the optimum choice, unless the used system is replaced with a clean **PERF***FLOW* fluid prior to drilling into the pay zone.

Mixing Procedures

Ensure all pits, lines and pumps are clean and have been flushed with water/sea water prior to mixing. The mixing sequence depends on the products being used. When using W-306™, the following mixing order is recommended.

Water/Brine	.87 - .90 bbls
W-306	2.0 gals/bbl
MIL-CARB™	50 lbs/bbl
X-CIDE® 102	0.01 - 0.015 gals/bbl
KCl*	1% - 3%

**Recommended in lower density brine applications, especially where reactive shales or clays are anticipated.*

In higher brine weights, (above 12.5 ppg), W-306 is the product of choice. When mixing W-306 in brines (above 11.0 ppg $CaCl_2$), a shearing device that would also increase the temperature of the mix water to the range of 120°F to 130°F is recommended. This will enhance hydration of the polymers and allow optimum fluid property development.

KCl additions are recommended for additional inhibition should shale stringers be encountered while drilling the production zone. Also, the W-306 should be allowed to disperse in the mix brine for 1 to 2 hours before the addition of the MIL-CARB™.

The following mixing order is recommended if **PERF***FLOW* DIF is used.

Water/Brine	.94 bbls
PERF*FLOW*® DIF	55 lbs/bbl
X-CIDE® 102	0.01 - 0.015 gals/bbl
Magnesium Oxide	3 lbs/bbl
KCl	1% - 3%

The **PERF***FLOW* DIF can be mixed in all types and densities of brines. When using divalent salts such as $CaCl_2$ to build a **PERF***FLOW* system, 3 lbs/bbl of Magnesium Oxide as a pH buffer are recommended. Once the **PERF***FLOW* system has been mixed, and additional viscosity is required, small additions of W-306 can be added to the system. Prior to these additions, pilot testing should be performed to determine the exact quantity required to achieve the desired results.

If displacement volumes are to be mixed on location, care should be taken when mixing the initial volume. Small batch mixes are recommended initially to prevent calcium carbonate from settling out of the system due to a poorly agitated fluid tank.

Should time constraints prohibit mixing small batches of fluid, consideration should be given to adding a small quantity (⅛ to ¼ lb/bbl) of Xanvis® or XANPLEX® to the initial mix water before the **PERF***FLOW*® additions are initiated. This will prevent any calcium carbonate from settling out of the system.

Typical PERF*FLOW* System Properties

Brine	**KCl**	**NaCl**	**$CaCl_2$**	**$CaCl_2/CaBr_2$**
Fluid Weight	9.2	9.7	11.4	13.5
Funnel Viscosity	40 - 50	40 - 50	40 - 50	55 - 65
Plastic Viscosity	10 - 20	15 - 25	20 -30	60 - 70
Yield Point (YP)	20 - 25	20 - 25	20 -30	20 - 30
Gel Strengths	4 / 7	4 / 7	4 / 7	5 / 8
API Fluid Loss	< 4	< 4	< 4	< 4
pH	8.5 - 9.0	8.5 - 9.0	7.5 - 8.5	7.5 - 8.5

Maintenance and Treatment of PERF*FLOW* Systems

A **PERF***FLOW* fluid is essentially a polymer-base fluid with varying salt content, and therefore, treatment and maintenance are similar to these fluids. There is one important exception. The integrity of the fluid composition should be maintained to preserve the formation protection properties of the fluid.

In preparing new volumes of **PERF***FLOW*, the recommended amount of each additive should be strictly followed. Build whole dilution volume or displacement volume for the system. Do not simply add neat brine.

In the same respect, drilling fluid additives not normally used in the system should be pilot tested before use to determine if they have any adverse affect on the bridging properties of the fluid and increase formation damage.

Density – Final fluid density will depend primarily on the density of the starting brine. The addition of the **PERF***FLOW*® components to the brine will increase the final fluid density by 0.5 to 0.6 lbs/gal. Therefore, the density of the starting brine should be chosen with this increase in mind. Should increases in fluid density be required, there are three options available.

1. Weight the system with the salt being used (NaCl, $CaCl_2$, etc.)
2. Weight the system with MIL-CARB™
3. Add a higher density **PERF***FLOW* fluid.

Note: *Be aware that using MIL-CARB to weight the system may compromise the system's effectiveness since the original system design is based on 50 lb/bbl of specially graded calcium carbonate.*

Rheology – Under normal circumstances, fluid treatment for incremental increases in rheology are not required with the system. However, should increased rheology be necessary, small additions of W-306™ (depending on the initial system make-up) or other products such as Xanvis® or XANPLEX® can be used.

Note: *Please note that additions of W-306 will lower the fluid loss of the system as well as increase rheology. Prior to these additions, pilot test to determine the exact quantity needed.*

Fluid Loss – Initial API fluid loss of the **PERF***FLOW* systems should be ≤ 5.0 cc and in most cases, ≤ 4.0 cc per 30 minutes, and should require no adjustment. However, should reduced fluid loss become necessary, small additions of W-306 (depending on the initial system make-up) can be used.

pH – The fluid's pH should be maintained within the 7.5 to 9.0 range. The choice of the system's brine phase will determine the product used to make any adjustments. Most salts such as NaCl or KCl fall in this pH range and, for this reason, no alkalinity control agents, such as caustic soda or caustic potash, are added to the preparations, initially. They may be used if required. The pH of the brine to be used in the preparation of the fluid may dictate an acid environment such as in the case with $ZnBr_2$ or sometimes in the 11 pH range as noted for some commercial $CaCl_2$ brines. In a calcium type brine, magnesium oxide is recommended. Prior to making the addition, pilot test to determine the exact quantity needed.

The polymers used in the **PERF***FLOW*® fluids are reasonably tolerant of pH extremes, but where the fluid is to be used for an extended period of time, higher maintenance of viscosity and filtration control properties should be expected. In the case of cement contamination, the pH of the fluid should be allowed to drift downward as quickly as possible. Where repeated contamination with cement occurs, or the cement is quite green, it may be advisable to treat with a mild acid such as citric or acetic. These acids should be used only to moderate the high pH, thus lowering a 12 pH into the 10.5 to 11 pH range. Never attempt to adjust the fluid pH below 10 as the acid will be spent on the calcium carbonate in the system. An alternative fluid should be used to drill cement plugs and casing shoes to preserve the purity of the **PERF***FLOW* fluid for the drill-in operation.

MBT – The MBT values should be monitored closely as the initial system is built with no reactive clays. An increase in MBT indicates shale stringers are being drilled in the producing formation. These increases will help determine when displacement volumes are required to keep the system in optimum ranges. Lab data indicates a severe reduction in return permeability when MBT values are allowed to increase above 5 lbs/bbl. Partial displacement with fresh fluid should be made to maintain the MBT below 5 lbs/bbl.

System Troubleshooting Guide

Problem	Possible Cause	Recommended Action
Increase in Fluid Loss	1. Shift in particle size 2. Polymers degrading 3. Bacterial problem	1. Pilot test to determine displacement volume required. 2. Pilot test with W-306™. 3. Pilot test 1 gallon X-CIDE® 102 per 100 bbls fluid.
Increase in Rheology	1. Shift in particle size 2. Incorporated solids	1. Pilot test to determine displacement volume required. 2. MBT increased, pilot test for displacement volume.
Decrease in Rheology	Polymers degrading	Pilot test with W306, Xanvis®, or XANPLEX to determine treatment level.
Slugging Pipe for trip	Air entrapment	Add 1/8 to 1/4 gallon LD-8® per 10 bbls of slug volume. Use Salt for a portion of the slug weight
Foaming	High Surface Tension	Elevate pH to 9.0. Add defoamer LD-8
Stuck Pipe	Aggressive build rate	Acetic Acid spot. Consult Tech. Services before spotting.

Solids Control

It is necessary to limit the amount of reactive and non-reactive drill solids in the **PERF***FLOW*® fluid, particularly just prior to drilling the pay zone. Therefore, the most effective shaker screen size must be used while using the fluid for drilling. Approximately 95% of the calcium carbonate particles in a **PERF***FLOW* fluid are less than 128 µm. A good linear motion shaker should be able to use a screen size of 80 to100 mesh without excessive loss of fluid or the bridging components.

Desanders and desilters should be bypassed at this stage of drilling. If sand content in the system appears to be a problem, check that the sand content readings are in fact sand. Add a small amount of HCl acid to the sand content tube with the suspected sand. If the sample effervesces, calcium carbonate is being mistaken for sand.

Should the sample actually be sand, installing smaller mesh screens (up to 100 mesh) would be recommended before running the desander. Should the sand continue to increase, run the desander periodically until sand levels become acceptable.

Note: *Use of centrifuges is not recommended.*

Drilling and Wellbore Behavior

As a drilling fluid, the **PERF***FLOW* system provides similar performance to polymer-base fluids which, because they exhibit shear thinning rheology, should enhance the rate of penetration. However, the use of higher-density salt brines such as calcium chloride or calcium bromide will result in higher apparent viscosity which may retard ROP to some extent. The **PERF***FLOW* fluids have inherent lubricity and should be adequate for most well conditions. Lubricants should be checked for formation damage potential before addition of a **PERF***FLOW* fluid.

Displacement of PERF*FLOW* Drill-In Systems

Once the well has reached TD, circulate a minimum of one bottoms up, short trip into casing. Go back to bottom, circulate a minimum of one bottoms up. If well conditions are stable, displace the **PERF***FLOW* DIF system with a completion brine or “virgin” **PERF***FLOW* system (contains no calcium carbonate; same weight as standard **PERF***FLOW* system) as follows.

Brine (same weight as **PERF***FLOW* system), volume = to open hole + 500 ft inside casing

Completion Brine and *W-306™* — Equivalent density brine or brine with 2 gal/bbl W-306

- Once the completion brine or “virgin” pill has been spotted in open hole, pull 500 ft inside casing.
- Monitor well conditions to ensure stability. If no losses are observed, pump the following displacement pill followed by the completion fluid.

Brine (same weight as **PERF***FLOW*® system) — 50 bbls; W-306 @ 3 gpb

- Pump out of hole and pick up completion equipment.
- Once all equipment has been picked up, circulate through equipment to ensure there are no restriction problems.
- Once equipment is on bottom, circulate the “virgin” **PERF***FLOW* out of the open hole and above the packer with a high viscosity pill, as follows, if “virgin” **PERF***FLOW* was used.

Brine (same weight as **PERF***FLOW* system) — 50 bbls; W-306 @ 3 gpb

- Circulation rate should be the maximum allowable, but caution should be exercised as over pressure can cause the packer to set prematurely.
- Once the high-viscosity pill has been circulated above the packer, reset the running tool and reverse circulate the high-viscosity pill and **PERF***FLOW* out of the well.

It is the operator’s decision to pump acid. An acid wash, however, is usually unnecessary if a gravel pack job is performed. If prepack screens are run, produce the well and evaluate its productivity. If performance does not meet expectations, acidize.

Note: *Never use HEC in conjunction with any* **PERF***FLOW system.*

Acid Clean-up Procedure

PERF*FLOW* DIF, 100 & HD Systems (for Applications < 180°F)

The following PERF*FLOW*® Clean-up Procedure is intended as a back-up procedure if a well is not producing as expected after drilling with PERF*FLOW* DIF or PERF*FLOW* 100. The formulation is designed to oxidize and hydrolyze the biopolymer and starch found in each system by spotting a strong oxidizing agent mixed with 10% HCl. The HCl will assist in the polymer breakdown and will also dissolve the MIL-CARB™ in the filtercake.

Typically, coiled tubing with a jet tool is used to deliver a clean-up solution across the gravel pack and/or completion screens. If coiled tubing is not available, an open ended workstring can be used. Just as with coiled tubing, the treatment soak is pumped across the inside of screens through the workstring beginning at the toe and retrieved at a rate necessary for coverage of the spot across the entire reservoir interval. An ISAP tool can be used to place acid across long intervals. This is especially useful in cleaning up horizontal wells.

If the anticipated BHT is 100°F or lower, it is recommended that PERF*FLOW* 100 be used as the drill-in fluid. As the BHT approaches 150°F, either PERF*FLOW* DIF or PERF*FLOW* 100 filtercakes can be successfully treated with acid.

The recommended volume of the acid/oxidizer soak is based on applying 5 to 10 gallons per perforated foot of reservoir. The volume of acid required per foot can be calculated using the amount of calcium carbonate left on the borehole from the PERF*FLOW* filtercake. (See acid volume calculation at end of section.) Once the clean-up solution is spotted, allow to soak for one hour if the BHT is > 150°F (4 hours if < 120°F). Reciprocate and circulate out soak fluid with the coil or workstring prior to placing the well on production.

Acid/Oxidizer Soak Formulation

- 10% HCl – quantity dependent on the open hole annular volume
- W-326 – (50 lb/1000 gal. acid) – Oxidizing agent
- FE-400 – (25 lb/1000 gal. acid) – Iron chelating agent
- CI-200 – (2 gal/1000 gal. acid) – Corrosion inhibitor
- MS-100 (5% by vol.) – Mutual solvent

Notes/Comments

1. FE-400, MS-100 and CI-200 are Baker Oil Tool products.
2. Corrosion inhibitor concentration will increase as the BHT exceeds 180°F and or contact time exceeds 4 hours. A corrosion inhibitor intensifier may be deemed necessary for long contact times or temperatures exceeding 180°F.
3. Oxidizer (W-326) should be added to cool pre-mix 10% HCl
4. MS-100 (Mutual Solvent)
   - Can be used in oil & gas well applications
   - Water wets fines which could stabilize emulsion blocks
   - Minimizes adsorption of cationic surfactants and improves their solubility
   - Eliminates water blocks; improves relative permeability to oil & gas
   - Aids in water wetting the formation which allows for more effective acid contact
5. Disclaimer – The clean-up solution containing HCl acid should be tested for compatibility to the formation and formation fluids prior to pumping. An alternative acid, such as acetic acid, may need to be used in place of HCl for formation compatibility reasons.

6. Pickling of workstring prior to placement of the soak is also suggested. The pickling fluid can be the same as the clean-up fluid.

Acid Calculation

Given the following chemical facts:

1. $CaCO_3 + 2HCl \text{ -----> } CaCl_2 + H_2O + C0_2$
2. Stochiometrically, 100 lb $CaCO_3$ reacts with 73 lb HCl or 0.73 lbs HCl dissolves 1 lb of $CaCO_3$
3. Concentrated HCl is 36% by weight with a density of 1.18 or 9.84 lb/gal
4. Therefore, there is (0.36)(9.84) = 3.54 lb. of HCl in one gallon of concentrated HCl.

On this basis:

1. 10% HCl has 0.354 lbs of HCl per gallon
2. 15% HCl has 0.531 lbs of HCl per gallon

   and

3. 2.062 gal of 10% HCl dissolves 1 lb of calcium carbonate or,
4. 1.375 gal of 15% HCl dissolves 1 lb of calcium carbonate

Given the following wellbore conditions:

With this information, *estimate* the amount of acid that must be spotted to remove the MIL-CARB™ in the filtercake:

1. Hole size = 6' or 15.24 cm
2. Cake thickness = 1 mm or 0.1 cm
3. Cake solids are 30% by vol. water
4. MIL-CARB™ is 92% calcium carbonate
5. Cake solids are essentially all calcium carbonate
6. MIL-CARB density = 2.7 g/cc

Assuming:

1. There is (1cm)(1cm)(0.1cm) = 0.1 cc of volume of cake in 1 cm^2 of hole area.

2. There is (3.14)(15.24)(30.48) = 1458.6 cm^2 of surface area in 1 ft of open hole.
3. Therefore, cake volume = (1458.6)(0.1) = 145.9 cc of cake per ft of hole.
4. MIL-CARB estimate per ft of hole = (145.9)(0.70)(2.7)(0.92) = 253.6 g MIL-CARB in 1 ft of cake or 253.6/454 = 0.559 lbs of MIL-CARB.
5. If 1 lb of calcium carbonate requires 2.062 gal of 10% HCl, then 0.559 lbs requires 1.12 gal of 10% HCl or a little over 1 gal of 10% HCl per ft of 6" hole. The rule of thumb in the field is about a 50% over this. The excess is used because field acid concentrations are not always known accurately and because the acid is partially expended on the other downhole materials.

BIO-LOSE 90

Introduction

The BIO-LOSE™ 90 system was developed for use as a low solids horizontal drilling fluid which would provide low dynamic fluid loss and rheology parameters which are compatible with long horizontal sections. Its primary use is in fractured formations, both sand and calcareous.

The primary viscosifier used is DRISPAC®, with BIO-LOSE™ added to control fluid loss. BIO-LOSE is a nonfermenting, chemically modified starch which does not require any biocides and can be used over a wide pH range in most water-base fluids. The third product required in the make-up of a BIO-LOSE™ 90 system is MILBREAK®, which will prevent any emulsification from occurring as drilling progresses. When mixed according to guidelines, no further additives will be required.

Rheology

The BIO-LOSE 90 system can easily be adjusted to the operators specifications if changes in rheology are required. The Yield Point (YP) is usually maintained at 3 to 4 Pa (6 to 8 lb/100 ft^2) to ensure the system will be in turbulent flow.

Fluid Loss

Under normal conditions, the fluid loss is < 6.0 cc/30 min. A very tight filter cake will be formed and laboratory tests have shown the dynamic fluid loss to be very low. The concentration of BIO-LOSE required is 13 to 14 kg/m^3 (4 to 5 lb/bbl).

Reservoir Considerations

After drilling over 180 wells with the BIO-LOSE 90 system, Baker Hughes INTEQ has found this fluid system to be very compatible with formation fluids. Laboratory testing is available and return permeability tests have been conducted on this fluid system with very favorable data results. The presence of an emulsification inhibitor ensures that minimal formation damage will occur as the reservoir is penetrated.

Fluid Density

The BIO-LOSE 90 system can be maintained in a density range of 1020 to 1030 kg/m^3 (8.5 to 8.6 ppg) if adequate solids control equipment is available. The solids content of the fluid should be monitored closely and if the level climbs above 2%, consideration should be given to discarding fluid. In most cases, the hole volume should be displaced with fresh fluid every 175 to 200 m (575 to 650 ft) of new hole.

Directional Tools

In the BIO-LOSE 90 system, there are no additives which could prove detrimental to the directional drilling equipment. If a bridging agent is required, Baker Hughes INTEQ recommends the addition of various grades of calcium carbonate, which will not affect the performance of downhole tools. Drilling fluid losses have been minimal when using the BIO-LOSE™ 90 system without any bridging agent – even when drilling a carbonate zone where the primary porosity comes from microfracturing.

Recommended Fluid Properties

Fluid Density	1020 - 1030 kg/m^3 (8.5 - 8.6 lbs/gal)
Funnel Viscosity	35 - 45 sec/L (33 - 43 sec/qt)
Yield Point	2 - 4 Pa (4 - 8 lbs/ft^2)
pH	7.5 - 8.0
Fluid Loss	4.0 - 6.0 cc/30 min.
MILBREAK	0.5% - 1.0% by volume

Sample Well

Estimated Product Usage

Listed below is the recommended concentration of products required to make-up one cubic meter or one barrel of BIO-LOSE 90 horizontal drilling fluid.

- BIO-LOSE — 14.0 kg/m^3 (5.0 lbs/bbl)
- DRISPAC® — 1.4 kg/m^3 (0.5 lbs/bbl)
- MILBREAK® — 5.0 L/m^3 (0.2 gal/bbl)

The total product usage has been estimated assuming the hole volume will be replaced with fresh fluid every 175 to 200 m (575 to 650 ft). The surface system has been estimated to be 80 m^3 (500 bbl). This results in a total volume of 430 m^3 (2700 bbl) if drilling a 1200 m (3900 ft) lateral section.

Horizontal Section Requirement

- BIO-LOSE – 265 sacks (55# sacks)
- DRISPAC – 27 sacks (55# sacks)
- MILBREAK – 2100 Liters (Ten 55-gal barrels)

Conventional Fluid Systems

Spud Fluids

Spud fluids are used to initiate drilling operations. These fluids have maximum hole-cleaning characteristics and should be capable of being built quickly. They are often required to support unconsolidated formations. Table 2-19 shows a typical spud fluid formulation.

Table 2-19 Spud Fluid Formulations

Fluid Type	Product	Concentration (lb_m/bbl)
Fresh water spud fluids	MILGEL® MIL-LIME™ SUPER-COL Soda ash	20 - 25 1 - 2
SUPER-COL®/ Fresh water	SUPER-COL Soda ash	10 - 12 To reduce hardness below 150 mg/L
Salt water	SALT WATER GEL®	25 - 35
Seawater/Prehydrated Gel (Mix sea water and prehydrated gel 50:50)	MILGEL Caustic Lime	30 - 40 (Prehydrate in freshwater) 0.5 - 1.0 0.5 - 1.5

Maintenance and Tips

1. Build fresh volume as hole is drilled.
2. Add SUPER-COL or MILGEL as required for viscosity.
3. Use water to reduce viscosity. Thinners are not normally used with spud fluids.
4. Small amounts of lime may be added along with SALT WATER GEL to increase the yield of the clay.

Contaminants

Usually contaminants are not a problem, but SUPER-COL should not be used where chlorides are above 2000 mg/L or hardness cannot be reduced to less than 150 mg/L.

Clearwater Drilling

In areas where it is practical to drill with clearwater, it has been established that even small concentrations of clay solids cause significant penetration rate reductions. The most common method for removing drill solids is to add a flocculant such as MF-1 (a water-soluble organic polymer) at the flow line. The drill water is then circulated through large settling pits where the flocculated solids fall to the bottom and the clarified water is recovered for drilling. The flocculant is added continuously as a water solution during drilling. Table 2-20 indicates the amount of material to be used. If clearwater is not obtained with these amounts, increase treatment by increments of 1 lb_m per tour.

Table 2-20 Using Flocculants in Clearwater Drilling

	Rate of Penetration (ft / hr)					
	50	100	150	200	250	300
Hole Size	**lb_m per Tour**					
Up to 7"	1	2	3	4	5	6
8" to 10"	2	3	5	6	8	9
11" to 13"	2	4	6	8	10	12

Low-Solids Nondispersed Fluids

Low-solids nondispersed fluids are primarily used to obtain improved penetration rates and hole cleaning in areas where conventional gel-chemical fluid systems give poor to moderate performance. This type system uses various materials to *extend* the yield of the clays resulting in a significantly lower total solids content. Laboratory and field data show a strong correlation between use of *low-solids* fluids and improved penetration rates. In addition, proper use of these polymer *extenders* results in flocculation of low-yield solids (drill solids) and optimum effectiveness of mechanical removal equipment. Secondary benefits derived from this system include the following.

- Reduced water requirements
- Lower total transportation cost
- Reduced wear on pumps and surface equipment
- Improved bit life

Low-Solids Fluids (Freshwater)

The basic system is freshwater, bentonite, and an extender-flocculant such as BEN-EX. The concentration depends upon the suspension properties required for hole cleaning.

A typical system contains the following.

- 8 to 14 lb_m/bbl (22.8 to 39.9 kg/m^3) MILGEL®
- 0.05 to 0.1 lb_m/bbl (0.14 to 0.29 kg/m^3) BEN-EX
- 9.5 pH (adjusted with caustic soda)
- Ca^{++} below 150 mg/L (control with soda ash)

A typical BEN-EX composition exhibits the following properties.

Property	Value
Funnel viscosity	34 - 38 sec/qt
Plastic viscosity	5 - 7 cp
Yield point	6 - 9 $lb_f/100\ ft^2$
Gels	4 - 6 $lb_f/100\ ft^2$
Filtrate	12 - 15 cm^3

If additional filtrate control is required, 0.5 to 1.0 lb_m/bbl (1.4 to 2.8 kg/m^3) of water-soluble polyacrylate such as SPA may be used.

This system is easily maintained in the following manner.

1. Fluid density should not exceed 9.0 lb_m/gal (6% solids, by volume), and for maximum penetration rates, the fluid density should be controlled at 8.8 lb_m/gal (3%) or less solids.
2. The typical amount of BEN-EX required per ft of hole drilled to flocculate drilled solids is as follows.

Hole Size	6"	6" to 7"	7" to 8"	9" to 11"	11" to 13"
BEN-EX (lb_m/ft)	0.02	0.02	0.03	0.04	0.04

3. Always add the appropriate amount of extender when adding bentonite or barite to the system.
   - 2 lb_m extender for every 500 lb_m bentonite
   - 2 lb_m extender for every 4000 lb_m barite
4. Use available solids-control equipment, or dilute with water to control the drill solids to bentonite ratio at 2:1 or less.
5. Treat new volume (from water addition) with the extender and chemicals daily.
6. With weighted fluids, as weight increases, maintain lower bentonite concentration. See Table 2-21.

Table 2-21 Materials Required for Preparation of Nondispersed Weighted Fluids: For 100 bbl of Finished Fluid

Fluid Weight) (lb_m/gal)	Water (bbl)	MILGEL® (sacks)	BEN-EX or LO-SOL (lb_m)	MIL-BAR® (sacks)	SPA (lb_m)
9.0	96	14	7	38	10
9.5	94	14	8	56	15
10.0	92	14	9	83	20
10.5	90	14	10	110	25
11.0	88	14	12	138	30
11.5	86	14	13	166	35
12.0	84	13	15	194	40
12.5	82	13	15	221	45
13.0	80	12	17	249	50
13.5	78	11	19	277	55
14.0	76	10	20	304	60
14.5	75	10	22	332	65
15.0	74	9	23	360	70
15.5	72	9	24	385	75
16.0	70	8	25	412	80

Acceptable ranges for MILGEL and low-gravity solids are outlined in Table 2-22.

Table 2-22 Acceptable Ranges for MILGEL and Drilled Solids in Weighted Nondispersed Fluids

Fluid Weight (lb_m/gal)	MILGEL® (lb_m/bbl)	% Total Solids	MIL-BAR® (lb_m/bbl)	Drilled Solids (lb_m/bbl)
9.0	14	3 - 4	29 - 13	0 - 28
10.0	14	7 - 8	83 - 64	0 - 28
11.0	14	11 - 12	138 - 115	0 - 28
12.0	13	14 - 16	194 - 166	0 - 26
13.0	12	18 - 20	249 - 218	0 - 24
14.0	10	22 - 24	300 - 269	0 - 20
15.0	9	25 - 27	360 - 335	0 - 18
16.0	8	29 - 30	420 - 400	0 - 16

Contaminants

Low-solids nondispersed fluids are quite sensitive to chemical contaminants such as Ca^{++}, Mg^{++}, Cl^{-}, HCO_3^{-}, $SO_4^{=}$. In addition, improperly treated drill solids, and even bentonite and barite, can act as contaminants. The most common problem relating to fluid viscosity is inadequate treatment with an extender.

Specific chemical contaminant levels are as follows.

- [Ca^{++}] maximum, 100 mg/L: treat with soda ash or bicarbonate of soda.
- [Cl^{-}], 5000 to 10,000 mg/L: dilute with freshwater.
- [HCO_3^{-}], [$CO_3^{=}$] should be minimized.

Refer to Table 2-23 and Table 2-24 for problems in unweighted and weighted low-solids nondispersed fluids respectively.

Note: *For Table 2-23 and Table 2-24, N = Normal, L = Low, and H = High*

Table 2-23 Checklist for Unweighted Fluids (Low-Solids, Nondispersed)

Problem	Wt[1]	Viscosity	MBT[2]	Low-Density Solids	Ca[3]	Treatment
Weight too high	—	N	N	H	N	Increase settling time. Add extender or flocculant
	—	H	H	H	N	Potential bentonitic formation. Dilute, add extender
Viscosity too high	N	—	H	N	N	Dilute, add extender. Stop adding bentonite
	N	—	L	H	N	Add extender and bentonite. Check solids equipment
	H	—	H	H	N	Use solids-control equipment. Add extender and water
	N	—	N	N	N	Add extender
	N	—	N	H	H	Add soda ash and extender or flocculant
Viscosity too low	N	—	L	N	N	Add bentonite and extender
	N	—	H	N	N	Pilot test with extender. Add extender or reduce treatment
	N	—	H	N	H	Treat calcium with soda ash
Fluid loss too high	—	N	L	N	N	Add bentonite and extender
	—		N	N	N	Add WL-100, SPA, or CMC.
	—	H	N	N	H	Remove calcium with soda ash or bicarbonate of soda

[1] Wt = Weight

[2] MBT = Methylene Blue Titration

[3] Ca = Calcium

Table 2-24 Checklist for Weighted Fluids (Low-Solids, Nondispersed)

Problem	Wt	Viscosity	MBT	Low-Density Solids	Ca	Treatment
Viscosity too low	N	—	L	N	N	Add extender and bentonite
	N	—	N	N	N	MBT, due to drilled solids, dilute, add gel and extender
Viscosity too high	N	—	H	N	N	Add extender or WL-100, SPA, or CMC
	N	—	N	N	N	Add extender or WL-100, SPA, or CMC
	N	—	N	N	H	Treat with soda ash or bicarbonate of soda (high pH)
HT / HP Fluid loss too high	N	N	N	N	N	Add bridging or coating agent (i.e., asphalics)
	N	N	L	N	N	Add bentonite-extender, and WL-100 or SPA
	N	N H	N	N	H	Remove calcium

Dispersed Fluids

Phosphate-Treated Fluids

Phosphates are used for deflocculating drilling fluids. The ones most commonly used are sodium tetraphosphate (OILFOS®), which has a pH near 7.0, and sodium acid pyrophosphate (SAPP), which has a pH near 4.0. They are most commonly used to control rheological properties in freshwater, low-solids systems. Treatments of 0.1 to 0.2 lb_m/bbl (0.3 to 0.6 kg/m^3) are normally sufficient when the system is maintained in the 8.0 to 9.0 pH range. Care should be taken to avoid overtreatment, which results in excessive viscosity.

Since SAPP sequesters calcium and reduces pH, it is often used to combat cement contamination. The amount required depends upon the severity of the contamination. However, as a general guide, 0.2 lb_m/bbl (0.6 kg/m^3) of SAPP will treat out approximately 200 mg/L of calcium ion.

Monitor the chemical properties of the fluid (P_m, pH, P_f, Ca^{++}) carefully. When the P_m to P_f ratio approaches 3:1, discontinue use of SAPP to avoid overtreatment.

Tannin and Lignin Fluids

Additives rich in tannin, namely quebracho, were commonly employed as thinners prior to the advent of lignosulfonates. The material is derived from the quebracho tree and normally has a pH of 3.8.

Most quebracho products are a quebracho-extract blend. These are used primarily as a thinner in freshwater drilling fluids for moderate-depth wells. The product is unstable at temperatures above 240°F (114°C). It also loses its effectiveness in environments containing excess salt (6000 to 7000 mg/L) or calcium ion (240 mg/L). The system can be maintained at a pH as low as 9.0, but it will tolerate more salt and calcium contamination at pH ranges of 10.5 to 11.5. When used as a thinner for freshwater fluids, 1.0 to 2.0 lb_m/bbl (2.8 to 5.7 kg/m^3) are usually sufficient.

The tannin most likely to be used is DESCO®. It is a sulfomethylated quebracho, applicable across a wide range of pH, with the optimum being 9 to 11. DESCO has a high tolerance for salinity and is used in sodium chloride brines. DESCO CF is a chrome-free version of DESCO.

Lignite materials (LIGCO®, LIGCON®, and CHEMTROL® X) are normally used for filtration control and are sometimes used in low-solids, freshwater fluids as thinners. When using lignitic materials, add sufficient caustic soda to obtain a fluid pH of 9.5 to 10.5. Generally, 1 lb of caustic will be required for every 2 to 4 lbs of lignite used. Treatments of 1.0 to 2.0 lb_m/bbl (2.8 to 5.7 kg/m^3) are normally recommended when these materials are used as thinners in freshwater fluids.

Lignosulfonate Fluids

Freshwater lignosulfonate fluids are commonly employed for drilling in areas where *mud making* formations are prevalent. They provide rheological control and afford a degree of inhibition to drill solids. Table 2-25 represents a typical freshwater/seawater lignosulfonate fluid formulation.

Table 2-25 Freshwater/Seawater Lignosulfonate Fluid Formulation

Fluid Type	Product	Concentration (lb_m/bbl)
UNI-CAL®	MILGEL® UNI-CAL® Caustic soda LIGCO® MIL-TEMP®/ALL-TEMP™ CHEMTROL® X	12 - 20 2 - 8 (for pH of 10.0 - 10.5) As needed As needed As needed

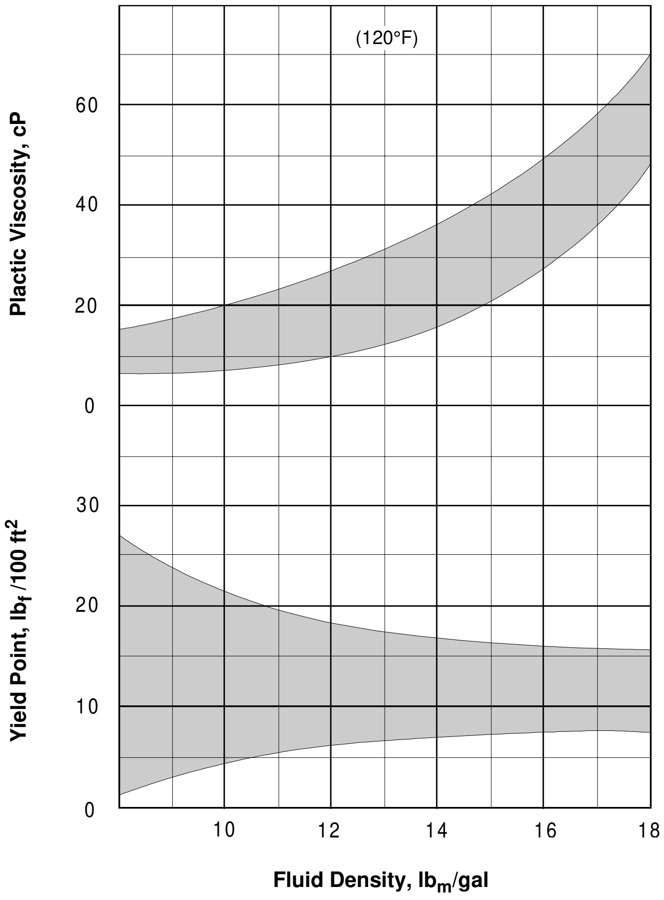
Maintenance and Tips

1. Add UNI-CAL daily or tourly to control yield point values. Treatment ranges between 0.5 and 1.0 lb_m/bbl will be sufficient for average penetration rates if a good solids-removal program is utilized.
2. MILGEL should be added as necessary to maintain desired filtration rates and give necessary suspension properties. MILGEL should be prehydrated before adding to the active system.
3. Water additions are required to maintain the plastic viscosity in the desired range. Depending on the fluid density, both UNI-CAL and water are usually required.
4. Drill solids may cause excessive problems with fluid rheology and should be kept as low as possible with mechanical-control devices and water.
5. CHEMTROL X and MIL-TEMP (or ALL-TEMP) may be utilized when fluid loss and rheology stabilization are required at high temperatures.

Seawater Fluids

Seawater is often used for fluid make-up and maintenance on inland barge and offshore drilling operations, primarily because of its availability and shale inhibition characteristics.

Figure 2-7 Average Range of Plastic Viscosity and Yield Point for Dispersed Water-Base Fluids



The composition of a typical seawater sample is shown below.

Constituent	mg/L
Sodium	10,400
Potassium	375
Magnesium	1,270
Calcium	410
Chloride	18,970
Sulfate	2,720
Carbon dioxide	90
(Density above – 8.5 lb$_m$/gal)	

Prehydrated bentonite mixtures can be prepared by mixing 30 to 35 lb$_m$/gal of MILGEL® in freshwater, containing 2 to 4 lb$_m$/bbl of UNI-CAL® and 0.2 to 0.4 lb$_m$/bbl of caustic soda. This mixture is generally added to the seawater at an initial concentration of 25% to 30% of circulating volume, then added as required while drilling. A defoamer such as LD-8® may be required (0.5 to 1.5 gal/100 bbl of volume) to control foaming.

As drilling progresses, it is usually necessary to disperse or deflocculate solids and lower fluid loss. Addition of 3 to 6 lb$_m$/bbl of UNI-CAL, 1.5 to 3 lb$_m$/bbl of LIGCON® or CHEMTROL® X, 0.25 to 1.0 lb$_m$/bbl of MIL-PAC™ and caustic soda as required for a 1.0 to 1.5 P$_f$ (10.0 to 10.5 pH). These concentrations result in a fluid with excellent flow properties and a filtrate value in the range of 4 to 8 cm^3.

To aid in filtrate control and cake quality, bentonite should be maintained (by Methylene Blue Test) in the 15 to 25 lb$_m$/bbl range. If inhibition from magnesium is desired, pH should be maintained below 10 (magnesium begins to precipitate as magnesium hydroxide at higher pH). Rheology and filtration control will be less difficult, however, if magnesium is precipitated.

Seawater fluids require substantially greater additions of caustic soda for alkalinity control. This is due in part to the loss of hydroxyl ion by reaction with magnesium.

MIL-PAC™, MIL-PAC LV, BIO-LOSE™, UNI-CAL®, LIGCO®, and/or LIGCON® are normally used for filtration control.

Saturated Saltwater Fluids

Saturated saltwater fluids are generally limited to drilling operations encountering salt formations and to workover operations. Saturated salt fluids are prepared by adding NaCl to water for saturation and then adding appropriate viscosifiers and fluid-loss control agents.

Characteristics

1. Normally utilize a saturated or near-saturated NaCl brine base (also use KCl).
2. Require good mixing conditions (high shear) or circulating time to develop good suspension properties.
3. Exhibit high gel strengths and yield point.
4. MILSTARCH ® or PERMA-LOSE™ HT begin to degrade at temperatures above 250°F (121°C). BIO-PAQ™ is effective to 300°F (149°C). MIL-PAC or MIL-PAC LV may be used as a supplemental filtration-control agent in these higher temperature applications.
5. Higher alkalinities are less corrosive and, where $P_f = 1.0$ or greater, reduce the tendency to foam.
6. LD-8® or W.O.™ DEFOAM help reduce foaming problems. These materials are most effective when added to the brine before mixing other materials.
7. Starch fermentation is generally not a problem if the system is saturated with salt or if pH is 11.5 or above. However, to ensure against starch fermentation, a suitable biocide may be added. BIO-LOSE or BIO-PAQ can also be substituted for starch. These products do not need a biocide.
8. Solids contents (retort analyses) of these fluids should be corrected to compensate for the effect of soluble salts.

Refer to Table 2-26 for a typical saturated salt fluid formulation.

Table 2-26 Saturated Salt Fluid Formulation

Product	Concentration
NaCl, lb_m/bbl	110
Prehydrated MILGEL®, lb_m/bbl	10 - 15
MIL-PAC™, lb_m/bbl	0.5 - 2.0
MIL-PAC LV, lb_m/bbl	0.5 - 2.0
BIO-LOSE™, BIO-PAQ™, lb_m/bbl	1.5 - 3.0
or	
PERMA-LOSE™ HT, lb_m/bbl	4.0 - 6.0
NEW-DRILL® HP, lb_m/bbl	0.25 - 4.0
LID-8	As required for foam
UNI-CAL®, lb_m/bbl	2.0 - 6.0
Caustic soda	pH = 10.5 - 11.0
CHEMTROL® X, lb_m/bbl	1.0 - 8.0
Prehydrated LIGCO®, lb_m/bbl	2.0 - 8.0

Calcium-Base Fluids

Calcium-based fluids are often used in areas where shale hydration and swelling result in significant borehole instability (i.e., sloughing and heaving). Increased levels of soluble calcium are maintained in these fluids to provide an inhibitive environment to minimize shale swelling.

The two basic types of calcium-base fluids are as follows.

- Lime [$Ca(OH)_2$]
- Gypsum [$CaSO_4 \bullet 2H_20$]

Refer to Table 2-27 for calcium-based formulation.

Refer to Table 2-28 for properties of lime and gypsum fluids.

Table 2-27 Calcium-Base Formulation

	Product	Concentration (lb_m/bbl)
Breakover to LIME fluid[1]	UNI-CAL®	2.0 - 4.0
	Caustic Soda	1.0
	Lime	4.0 - 8.0
	MIL-PAC™	0.5 - 1.0
Breakover to GYPSUM fluid[1]	UNI-CAL	3.0 - 6.0
	Gypsum	4.0 - 6.0
	Caustic Soda	1.0
	MIL-PAC	0.5 - 1.0

Table 2-28 Typical Properties of Lime and Gypsum Fluids

Low Lime[2]		Gypsum[2]	
Wt	10.0 lb_m/gal	**Wt**	10.0 lb_m/gal
Viscosity	40 - 44 sec/qt	**Viscosity**	40 - 44 sec/qt
PV	18 cP	**PV**	18 cP
YP	6 lb_f /100 ft^2	**YP**	6 lb_f /100 ft^2
Gels	0/0 lb_m/ft^2	**Gels**	2/10 lb_m/ft^2
API filtrate	6 - 12 mL	**API filtrate**	4 - 8 mL
Calcium	75 - 200 mg/L	**Calcium**	600 - 1200 mg/L
pH	11.5 - 12.0	**pH**	9.5 - 10.5
P_f	1.0 - 2.0 mL	**P_f**	0.2 - 0.7 mL
P_m	5.0 - 10.0 mL		
Excess lime	1 - 2 lb_m/bbl	**Excess gypsum**	2 - 4 lb_m/bbl

1. Concentration may vary with the condition of the fluid and its total solids content before breakover. When the solids content is high, a 10% to 15% water dilution will help to reduce the severity of the “viscosity hump”.
2. These numbers are estimates and may vary due to nature and quantity of solids in a converted fluid.

Maintenance and Tips

1. Conversion to a lime or gypsum fluid is best accomplished after a bit trip inside casing before drilling ahead.
2. Stack the necessary chemicals (gypsum or lime, deflocculant, caustic soda) close to their point of use. Add gypsum and deflocculant through the hopper. Add caustic soda directly to the fluid in the mixing pit.

CAUTION: *Do not add caustic soda through the hopper.*

3. Conversion materials should be added at timed intervals over one or two complete circulations.
4. Maximum agitation should be maintained in the suction and/or mixing pit.
5. The addition of gypsum or lime and DRISPAC® simultaneously through the hopper should be avoided because of drastic viscosity increases.
6. Treatments of gypsum or lime, caustic soda, UNI-CAL®, and a fluid-loss control agent are normally required each tour.
7. Lime or gypsum is added to maintain filtrate calcium. Sodium chloride can also be added to increase soluble calcium concentration.
8. In the absence of sodium chloride, the solubility of lime or gypsum is controlled by the pH of the system. The solubilities of lime and gypsum, as well as the corresponding soluble calcium content, decrease as pH increases (this effect is much more pronounced in lime fluids). Therefore, pH control is important in maintaining the proper level of free calcium.
9. Lime fluids are normally considered to be in good shape when the gel strengths are low and flat ($\frac{1}{2}$ to $\frac{2}{5}$). Lime additions do not cause viscosity increases.

10. Classification of Calcium-Base Fluids

High-lime Fluid

- 5 to 10 P_f
- 5 to 15 lb_m/bbl (14.3 to 42.3 kg/m^3) excess lime
- 100 to 300 mg/L calcium

Low-lime Fluid

- 0.8 to 2.0 mL P_f
- 1.0 to 2.5 lb_m/bbl (2.85 to 7.1 kg/m^3) excess lime
- 100 to 300 mg/L calcium

Gypsum Fluid

- 0.2 to 0.7 P_f
- 2 to 4 lb_m/bbl (5.7 to 11.4 kg/m^3) excess lime
- 600 to 1200 mg/L calcium

Fluid Contamination and Treatment

Table 2-29 summarizes the various contaminants and treatment methodologies of water-base fluid systems.

Table 2-29 Common Fluid Contaminants and Treatment

Contaminant	Compound/ Ion	Source	Method of Measurement	Possible Effect on Fluid	Course of Action
Anhydrite, Gypsum	$CaSO_4$, $CaSO_4 \bullet 2H_2O$ / Ca^{++}, SO_4^2	Formation, Commercial gypsum	Ca^{++} titration	High yield point. High fluid loss. High gels. Thick filter cake. Ca^{++} increase.	Treat with Sodium carbonate (soda ash) Ca^{++} (mg/L) $\times 0.00093 \equiv Na_2CO_3$ (lb_m/bbl) Break over to a gypsum fluid.
$MgCl_2$	$MgCl_2$ / Mg^{++}, Cl^-	Formation, Seawater	Total hardness, Cl^- titration	High yield point. High gels. High fluid loss. Thick filter cake. Total hardness increase. pH decrease. P_f decrease. Cl^- increase	Treat with caustic soda, NaOH ($pH \geq 10.0$) for moderate contamination, e.g., seawater Mg^{++} (mg/L) $\times 0.00116 \equiv NaOH$ (lb_m/bbl) Treat with additional thinner and fluid-loss chemicals. Convert to $MgCl_2$ fluid if contamination is severe. **NOTE**: *For severe contamination, continued additions of Na(OH) or $Ca(OH)_2$ will result in an unacceptable viscosity increase.*

Table 2-29 Common Fluid Contaminants and Treatment (continued)

Contaminant	Compound/ Ion	Source	Method of Measurement	Possible Effect on Fluid	Course of Action
Cement, Lime	$Ca(OH)_2$ / Ca^{++}, OH^-	Cement, Commercial lime, Contaminated barite	Titration for Ca^{++}, P_m	High yield point. High fluid loss. Thick filter cake. pH increase. P_m Increase. Ca^{++} increase.	Treat with sodium bicarbonate Ca^{++} (mg/L) × 0.00074 ≡ $NaHCO_3$ (lb_m/bbl)
					Treat with SAPP Ca^{++} (mg/L) × 0.00097 ≡ $Na_2H_2P_2O_7$ (lb_m/bbl)
					Treat with lignite, 7 to 8 lb_m/bbl precipitates 1 lb_m/bbl $Ca(OH)_2$ to form Ca^{++} salt of humic acid.
					Additional thinner/fluid loss chemicals.
					Centrifuge to remove contaminant particles.
					Dilution
					Dump if flocculation cannot be controlled
					Allow $Ca(OH)_2$ to remain and convert to lime fluid or allow $Ca(OH)_2$ to deplete over time.
					In some cases, use acids such as HCl, phosphoric.
					Treat with soda ash if light contamination Ca^{++} (mg/L) × 0.00093 = Na_2CO_3 (lb_m/bbl)

Table 2-29 Common Fluid Contaminants and Treatment (continued)

Contaminant	Compound/ Ion	Source	Method of Measurement	Possible Effect on Fluid	Course of Action
Cement, Lime					Since effects of pH are often more detrimental to fluid order, chemical treatment should be: 1. Sodium bicarbonate 2. Lignite 3. SAPP 4. Soda ash
					Sodium bicarbonate is treatment of choice.
Salt	NaCl / Na^+, Cl^-	Formation, i.e., salt dome, stringers, saltwater, make-up water	Cl^- titration	High yield point. High fluid loss. High gels, Thick filter cake. Cl^- increase.	Dilution with fresher water.
					Addition of thinner/fluid-loss chemicals reasonably tolerant of NaCl.
					Convert to salt fluid using chemicals designed for salt.
					Presolubilize chemicals where possible.
					Dump if flocculation is too severe for economical recovery

Table 2-29 Common Fluid Contaminants and Treatment (continued)

Contaminant	Compound/ Ion	Source	Method of Measurement	Possible Effect on Fluid	Course of Action
Carbonate, Bicarbonate	CO_3^{-2}, HCO_3^-	Formation CO_2 gas, thermal degradation of organics, contaminated barite, overtreatment with soda ash or bicarbonate.	Garrett Gas Train, pH/P_f method, P1/P2, P_f /M_f titration	High yield point. High 10-min gels. High HT HP fluid loss. Ca^{++} decrease. M_f increase. pH decrease	Treat with lime HCO_3^- (mg/L) × 0.00021 ≡ $Ca(OH)_2$ (lb_m/bbl) and CO_3^{-2} (mg/L) × 0.00043 ≡ $Ca(OH)_2$ (lb_m/bbl)
					Treat with gypsum CO_3^{-2} (mg/L) × 0.001 ≡ $CaSO_4 \bullet 2H_2O$ (lb_m/bbl) and caustic soda HCO_3^- × 0.0025 ≡ NaOH (lb_m/bbl)
Hydrogen Sulfide	H_2S / H^+, $S^=$	H_2S from formation gas, thermal degradation of organics, bacterial action.	Garret Gas Train (quantitative). Automatic rig H_2S monitor (quantitative). Lead acetate test.	High yield point. High fluid loss. Thick filter cake. pH decrease. P_m decrease. Ca^{++} increase.	Course of action to be in compliance with all safety requirements.
					Pretreatment/treatment with MIL-GARD or MIL-GARD R.
					Increase pH ≥ 11.0 with $Ca(OH)_2$, or NaOH.
					Condition fluid to lower gels for minimum retention of H_2S
					Operate degasser, possibly with flare.
					Displace with oil-base fluid. Add excess $Ca(OH)_2$ to precipitate $S^=$ and neutralize acid

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Calcium/Magnesium Contamination

Calcium/magnesium contamination causes viscosity and fluid-loss increases in freshwater clay-base systems. Calcium/magnesium may originate from make-up water, formation water, or drilling evaporite formations.

Treatments

1. Calcium Contamination from Formation/Make-up Water. [Soluble calcium from this source is usually treated with soda ash (Na_2CO_3).]

   Treatment with Soda Ash

   $Ca^{++} + Na_2CO_3 \rightarrow CaCO_3 \downarrow + 2Na^+$

   (0.000931 lb_m/bbl per 1.0 mg/L Ca^{++})

   Increasing the pH will also help to decrease the solubility of calcium (see Chapter 5).

2. Anhydrite/Gypsum Contamination

   Anhydrite/gypsum ($CaSO_4$/$CaSO_4 \bullet 2H_2O$) formations may be only several inches thick or several thousand feet thick. Flocculation and filtration-control problems result from drilling these formations. The problem is caused by increasing calcium concentration. If the beds are not massive, treat with soda ash.

   Treatment with Soda Ash

   $CaSO_4 + Na_2CO_3 \rightarrow CaCO_3 \downarrow + Na_2SO_4$

   (0.000931 lb_m/bbl per 1.0 mg/L Ca^{++})

   It may be necessary to provide additional filtration control with polymers such as PERMA-LOSE® HT or MIL-PAC™. Make additional viscosity decreases by using UNI-CAL®. In case of massive beds, conversion to a compatible system will be required. This is achieved by breaking over to a gypsum fluid with the addition of UNI-CAL, caustic soda, and filtration-control products.

3. Magnesium Contamination

   Magnesium is most often encountered when seawater is used as make-up water. The effects on the fluid system are similar to calcium. Magnesium is usually treated with caustic soda (NaOH). Most of the magnesium in a system will precipitate as insoluble $Mg(OH)_2$ when pH is greater than 10.5.

Treatment with Caustic Soda

$Mg^{++} + 2NaOH \rightarrow Mg(OH)_2 \downarrow + 2Na^{+}$

(0.00116 lb_m/bbl of caustic soda per 1.0 mg/L Mg^{++})

Cement/Lime Contamination

Cement contamination occurs when the casing is cemented and the cement plugs are drilled out. The severity of the contamination depends on a number of fluid factors (solids content, concentration of deflocculants, etc.) and the state of the cement (green or cured). Green cement poses more problems than cured cement. Cement contains several complex calcium compounds, all of which react with water to form calcium hydroxide [$Ca(OH)_2$]. A 100 lb_m quantity of cement can yield up to 79 lb_m of lime. Lime flocculates freshwater bentonite systems causing increases in rheology and fluid loss. Treating lime contamination involves reducing the pH and controlling the calcium concentration.

Measurement of Cement

The volume of one sack of cement (94 lb_m) when set is 1.1 ft^3. If the hole volume is 8.5 in., each foot of hole contains 26.5 lb_m of lime.

- 1 ft of 8.5 in. hole = 0.394 ft^3
- 1 ft^3 of cement = 85.5 lb_m of cement
- 85.5 $lb_m \times 0.394 = 33.7$ lb_m

$$33.7\ lb_m \times \frac{79\ lb_m}{100\ lb_m} = 26.5\ lb_m \text{ of lime}$$

Depending on whether the cement is cured or green, anywhere from 10% to 50% may be available to react with the fluid.

Excess lime can be estimated from the formula

$$\text{Excess lime, } lb_m/bbl = 0.26\,[P_m - (F_w\,P_f)]$$

where

P_m = fluid alkalinity,
P_f = filtrate alkalinity,
F_w = water fraction from retort.

Treatment

Several options are available for treatment of cement contamination. Generally a combination of treatments will be necessary.

1. ***Dump*** – If cement contamination reaches a level where, it is not practical to treat, dump the most contaminated fluid, displace the fluid system, or convert to a lime fluid.
2. ***Sodium Bicarbonate*** – Sodium bicarbonate reacts with soluble calcium to form insoluble calcium carbonate. Since pH values are high drilling cement, the quantity of calcium ions may not exceed 200 to 400 mg/L.

   Treatment with Sodium Bicarbonate ($NaHCO_3$)

   $Ca^{+2} + 2(OH^{-}) + Na^{+} + HCO_3^{-} \rightarrow CaCO_3 \downarrow + Na^{+} + OH^{-} + H_2O$

   (0.00074 lb_m of sodium bicarb treats 1.0 mg/L Ca^{++})

   Reaction with the lime will neutralize half of the hydroxyl ions in the lime. Further reduction in pH can be achieved by adding organic acids (UNI-CAL® and LIGCO®).
3. ***Sodium Acid Pyrophosphate*** (SAPP) – SAPP reacts with lime to form an insoluble calcium phosphate. The reaction is complex, but for treatment purposes, it can be represented as follows.

   Treatment with SAPP ($Na_2H_2P_2O_7$)

   $2Ca^{+2} + 4(OH^{-}) + 2Na^{+} + 2H^{+} + P_2O_7^{-4} \rightarrow Ca_2P_2O_7 \downarrow$
   $+ 2H_2O + 2Na^{+} + 2(OH^{-})$

   (0.00097 lb_m SAPP treats 1.0 mg/L Ca^{++})

   The reaction with lime is similar to that of sodium bicarbonate, but SAPP does not always react as completely. This results in additional amounts being required. If the bottomhole temperature is ≥ 175°F, SAPP can become a flocculant.

4. ***Organic Acids*** (UNI-CAL®, LIGCO®) – About 1 lb_m/bbl of lime can be neutralized with 7 to 8 lb_m of organic acids.

Additional Comments on Treatment

1. ***Soda Ash*** – Treatment of cement with soda ash is possible but not recommended unless carefully monitoring pH increases. In reacting lime with soda ash, none of the hydroxyl ions are neutralized. As the pH increases, the lime solubility will decrease, resulting in fewer Ca^{+2} ions to react with the $CO_3^=$ and a gradual increase in $CO_3^=$ concentration.

   Treatment with Soda Ash (Na_2CO_3)

$$Ca^{+2} + 2(OH^-) + 2Na^+ + CO_3^= \rightarrow CaCO_3\downarrow + 2Na^+ + 2(OH^-)$$

2. ***High Temperatures*** – At temperatures > 250°F solidification of cement-contaminated fluids may occur. Additions of 1 to 3 lb_m/bbl MIL-TEMP® or ALL-TEMP™ can stabilize flow properties of a cement-contaminated system.

Pretreatment

Pretreatment of the fluid system with sodium bicarbonate can cause carbonate contamination. It is not advisable to pretreat with more than 0.5 to 0.75 lb_m/bbl of sodium bicarbonate. Pretreatment with UNI-CAL or LIGCO will help buffer pH increases.

Sodium Chloride Contamination

Salt contamination can come from make-up water, saltwater flows, salt domes, or evaporite formations. Chemically, it can be sodium (Na^+), potassium (K^+), magnesium (Mg^{++}), or calcium (Ca^{++}) chloride, or a combination of all of these types. The most common is sodium chloride.

Salt will flocculate a freshwater-base fluid causing viscosity and filtration-control problems. If salt concentration is high enough, or of a divalent form (Ca^{++} or Mg^{++}), a shrinkage effect on the clays could cause a decrease in viscosity with a continued increase in fluid loss.

Treatment

Since salt cannot be precipitated by chemical means, salt concentrations can be reduced only by dilution with fresher water. In addition to dilution, deflocculation of the clays may be necessary, as well as fluid-loss reduction. Deflocculation can be accomplished with addition of UNI-CAL® and caustic soda. Fluid-loss reduction can be accomplished with polymers that are not sensitive to salt such as PERMA-LOSE™ HT (starch) and MIL-PAC™ (polyanionic cellulose).

In cases of prolonged salt contamination or large chloride increases that cause viscosity reductions, treatment with prehydrated bentonite will increase viscosity and lower fluid loss. With time, the prehydrated bentonite will also dehydrate, unless salt concentration is reduced. The beneficial effects of the prehydrated bentonite can be extended by treating it with UNI-CAL and caustic soda before adding to the active system.

In some cases, due to the increased solubility of the calcium ion as chlorides increase, it may be necessary to treat out the calcium ion with soda ash. Refer to the calcium/magnesium contamination section of this chapter for treatment amounts.

When making chemical additions to a salt-contaminated or a saltwater fluid, the additives should be prehydrated or presolubilized before addition to the system for optimum results.

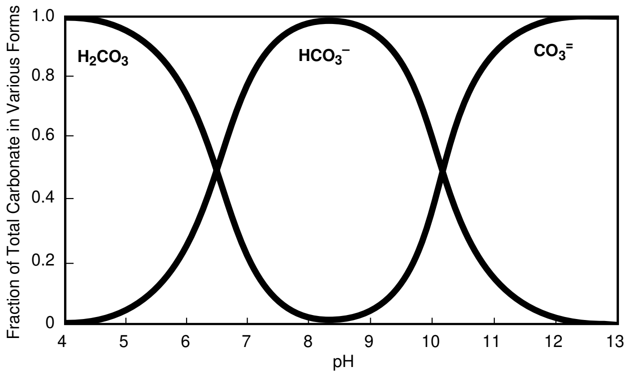
Carbonate/Bicarbonate Contamination

Rheological and filtration-control problems result when a water-base fluid becomes contaminated with carbonates. Carbonates may exist in one of three forms depending on the pH of the fluid: carbonic acid: H_2CO_3, bicarbonate: HCO_3^-, and carbonate: $CO_3^=$. Figure 2-8 shows the equilibrium points of these forms at various pH levels.

Carbonates may originate from several sources.

- Overtreatment with soda ash or bicarb to remove calcium or cement contamination
- Carbon dioxide dissolution due to formation gas, fluid-mixing equipment, swabbing fluid pumps, etc.

Figure 2-8 Solution Species Present in Carbonate Systems as a Function of pH - Calculated for $K_1 = 3.5 \times 10^{-7}$ and $K_2 = 6.0 \times 10^{-11}$



- Thermal degradation of organic compounds such as lignosulfonates, lignites, etc. at temperatures ≥ 300°F
- Contaminated barite

Measurements of Carbonates

The API has standardized three methods for the measurement of carbonates in drilling fluids. The recommended method is the Garrett Gas Train (GGT). The GGT is the only method that directly measures carbonates. All of the other methods use alkalinity data to infer the concentration of carbonates and bicarbonates in the fluid. The GGT procedure is discussed in Chapter 1.

The other two methods are the P1/P2 titration and the P_f / M_f carbonate calculation. The P_f / M_f method is the traditional method. The P1/P2 method was developed to overcome limitations in the P_f / M_f method which tends to greatly over estimate the bicarbonate concentration, particularly in highly buffered systems. The P1/P2 titration uses barium chloride to precipitate barium carbonate. Because barium chloride is poisonous and because the titrations are very sensitive, caution must be exercised when the method is used. Table 2-30 compares the advantages of the two methods. The calculations for using the P_f / M_f values to determine carbonate and bicarbonate concentrations are contained in Table 2-31.

The procedures for obtaining the P_f / M_f values used in the calculations are contained in Chapter 1. A condensed version of the API standardized P1/P2 titration procedure is reproduced in this section.

Table 2-30 Methods Comparison

Method	Advantage	Disadvantage
P_f / M_f	Traditional method; Only 2 titrations on a single sample	M_f titration interference; Bicarbonate result usually high
P1 / P2	Eliminates M_f titration interference	Requires 3 titrations on 3 samples; Caustic measurement critical to accuracy; Uses a toxic material

Table 2-31 P_f / M_f Alkalinity Ion Concentrations, mg\L

P_f / M_f Values	$[OH^-]$	$[CO_3^{-2}]$	$[HCO_3^-]$
$P_f = 0$	0	0	$1220\ M_f$
$2 P_f < M_f$	0	$1200\ P_f$	$1220 (M_f - 2 P_f)$
$2 P_f = M_f$	0	$1200\ P_f$	0
$2 P_f > M_f$	$340 (2 P_f - M_f)$	$1200 (M_f - P_f)$	0
$P_f = M_f$	$340\ M_f$	0	0

P1/P2 Alkalinity Method

Equipment

- 0.02 N Hydrochloric Acid solution
- 0.01 N Sodium Hydroxide solution
- 10% Barium Chloride solution, neutralized to pH 7 with NaOH
- Phenolphthalein indicator solution
- Deionized water
- pH paper strips, 6 to 12 range or pH meter
- 100 to 150 cm^3 titration vessel
- Volumetric pipettes (TD): one each, 1 cm^3 and 2 cm^3

- 25 cm^3 burette (TD)
- Graduated cylinders (TC): one each, 25 cm^3 and 5 cm^3

Procedure

1. Determine P_f as described in Chapter 1.
2. Using a volumetric pipette, measure 1.0 cm^3 of filtrate into titration vessel. Add 25 cm^3 of deionized water.
3. Using a volumetric pipette, add 2.0 cm^3 of 0.1N sodium hydroxide and stir well. Measure the pH. If 11.4 or greater, go to Step 5.
4. If the pH is less than 11.4, add 2.0 cm^3 more sodium hydroxide.

Note: *Exact measurement of the caustic is necessary to avoid errors.*

5. Using the smaller graduated cylinder, add 3 cm^3 barium chloride. While stirring, add 2 to 4 drops of the phenolphthalein indicator.
6. Immediately titrate the mixture with the hydrochloric acid to the first disappearance of the pink color or to a pH of 8.3 with a pH meter. If the color reappears after a short time, do not continue the titration.
7. Record the P1 alkalinity as the number of cm^3 of acid used to reach the endpoint.
8. Determine the blank alkalinity, P2, by repeating the above steps using exactly the same quantities of water and reagents but leaving out the filtrate.
9. Record the P2 (blank) alkalinity as the number of cm^3 of acid used in the titration.
10. Use Table 2-32 to determine the concentration of hydroxide, carbonate, and bicarbonate ions in solution.

Table 2-32 P1 / P2 Titration Ion Concentrations, mg\L

P1 / P2	[OH^-]	[CO_3^{-2}]	[HCO_3^-]
P1 > P2	340 (P1 – P2)	1200 [P_f – (P1 – P2)]	0
P1 < P2	0	1200 P_f	1220 (P2 – P1)

Alternate Method for Estimation of CO_3 / HCO_3

A mathematical model has been developed using the pH/P_f relation to estimate carbonate/bicarbonate concentrations. The method is simple to use and requires a minimum of time and equipment, but has not been adopted by the API. This method can give unreliable results at pH levels below 10.0 and should be used cautiously.

The method is as follows.

1. ***Measure pH*** – The pH of the filtrate should be determined to ± 0.1 accuracy using a pH meter. The pH of the fluid can be used if filtrate volume is limited.
2. ***Measure P_f*** – Alkalinity of the filtrate.

Carbonates are calculated using the following equations.

High pH Fluids

Hydroxyl concentration in mg/L (OH)

$$= 17{,}000 \times 10^{pH - 14} \tag{2-1}$$

Carbonate concentration in mg/L (CO_3)

$$= 1200\left(P_f - \frac{OH}{340}\right) \tag{2-2}$$

Bicarbonate concentration in mg/L (HCO_3)

$$= \frac{CO_3}{10^{pH - 9.7}} \tag{2-3}$$

Example

pH = 12.6

$P_f = 5.3\ cm^3$

OH = 677 mg/L

CO_3 = 3971 mg/L

HCO_3 = 5 mg/L

Low pH Fluids

It is difficult to measure P_f accurately when the pH is below 9.5. Therefore, the method must be modified in those cases. The procedure is as follows.

1. Increase the pH of the filtrate sample to 11.5 with a caustic soda (NaOH) solution.
2. Titrate and determine the P_f value at 11.5 pH.
3. Multiply the P_f at 11.5 pH by 1200 to determine mg/L total carbonates at 11.5 pH.
4. Calculate the bicarbonates and carbonates for the original pH,

$$\text{Bicarbonates, mg/L} = \frac{Y}{1 + 10^{pH-9.7}} \qquad (2\text{-}4)$$

$$\textit{Carbonates}\text{, mg/L} = Y - HCO_3 \qquad (2\text{-}5)$$

where

Y = total carbonates at 11.5 pH,

pH = pH of the original filtrate.

Treatment of Carbonates

A general range for carbonates in most fluids is 1200 to 2400 mg/L. Some fluids may tolerate twice this amount or be seriously affected by 1200 mg/L. The acceptable concentration of carbonates in a drilling fluid will always depend on the concentration of solids, temperature, and chemical concentrations.

If it is determined that rheological and filtration problems are being caused by carbonates, the method of treatment involves the addition of the calcium cation to form a precipitate of calcium carbonate. Calcium is added as either gypsum or lime. If gypsum is used, caustic soda or lime must be added to convert bicarbonates to carbonates or the reaction with calcium will not take place. If lime is used, the pH will increase. It may be necessary to add gypsum or lignosulfonate to buffer the pH increases. Avoid adding lignite because it reacts with gypsum and lime and will

interfere with the chemical reaction. It is also recommended that not all of the carbonates be treated out. A minimum of 1000 to 1200 mg/L should be allowed to remain in the system. The chemical reactions and treatment concentrations are given below.

Chemical Reactions

Lime [$Ca(OH)_2$]

$$CO_3^{=} + HCO_3^{-} + 2Ca^{++} + 4(OH^{-}) \rightarrow 2CaCO_3 \downarrow + H_2O + 3OH^{-}$$

Gypsum + Lime or Gypsum + Caustic Soda

$$CO_3^{=} + HCO_3^{-} + 2Ca^{++} + OH^{-} \rightarrow 2CaCO_3 \downarrow + H_2O$$

Reaction Amounts

Lime

0.00043 lb_m treats 1.0 mg/L $CO_3^{=}$

0.00021 lb_m treats 1.0 mg/L HCO_3^{-}

Gypsum

0.001 lb_m treats 1.0 mg/L $CO_3^{=}$ Caustic soda

0.00023 lb_m treats 1.0 mg/L HCO_3^{-}

Additional Comments

In determining whether a carbonate problem exists, the presence of calcium in the filtrate does not eliminate a carbonate problem. Calcium detected in the hardness titration may not be available to react with carbonates. Often the action of chelates, reduced reaction rates, and shifts in equilibriums will prevent the measured calcium from reacting with carbonates. At least 100 to 200 mg/L calcium should be measurable on the hardness test to ensure some free calcium is present to react with carbonates.

Alkalinity is routinely interpreted to represent carbonate, bicarbonate, and hydroxyl ions, but other alkaline materials contribute to the alkalinity of drilling fluids. These interferences and procedural limitations with testing make alkalinity titrations for carbonate analysis simple approximations. For this reason, the Garrett Gas Train provides greater accuracy. Regardless of which method is used, it is recommended to pilot test thoroughly before treating the fluid system for carbonates.

Hydrogen Sulfide Contamination

WARNING!!!
Hydrogen sulfide (H_2S) is *highly poisonous* as well as *corrosive*. Small concentrations in air *may be fatal in minutes*. When H_2S is expected, be thoroughly familiar with protective measures in advance. Although hydrogen sulfide can have adverse affects on viscosity, fluid loss, and fluid chemistry, ***safety is the most important issue***.

Measurement of H_2S

From a safety standpoint, any rig drilling in potential H_2S zones should be equipped with H_2S monitors and alarm equipment. The most reliable and accurate means of measuring the sulfide content in solution in the fluid is with a Garrett Gas Train.

The test involves injecting a sample of filtrate into a chamber of the Garrett Gas Train and injecting a strong acid into the filtrate. This converts all of the sulfides to a gas (H_2S). Nitrogen or carbon dioxide gas is then bubbled through the Garrett Gas Train carrying with it the H_2S. The gas flow is directed through a Drager tube at a controlled flow rate. The Drager tube stains if sulfides are present. The length of the stain times a correction factor determines sulfide concentration.

The exact procedure is given in Chapter 1, **Drilling Fluid Testing Procedures**.

Treatment of H_2S

The most effective method of controlling H_2S involves the use of MIL-GARD® (basic zinc carbonate) in conjunction with pH control.

Recommended Treatment

1. MIL-GARD® – 2 to 3 lb_m/bbl

   (0.002 lb_m/bbl treats 1.0 mg/L sulfide)
2. pH controlled at 10.0 or greater with caustic soda or lime

CAUTION: *Do not rely on pH control alone to control sulfides.*

Refer to the **Hydrogen Sulfide (H_2S)** section of Chapter 4 for additional discussion of treatment amounts and methods.

Borehole Problems

Wellbore Instability

Of the many types of rock encountered in the course of drilling, the one most susceptible to instability is shale. Shales are rocks that contain clay. They are formed by the compaction of sediments as the sediments are buried by the progressive deposition of additional sediments over geologic time. As the compaction occurs, water is squeezed out of the shale. The degree of compaction is proportional to the depth of the burial, provided the water is free to escape the shale.

If the water does not escape the shale, then the water supports a portion of the overburden and the shale becomes *pressured*. If the water does escape the shale, the rock becomes *dehydrated*. Shale problems are a direct result of the way in which the shale reacts with the water from the drilling fluid. Hydration from water tends to reduce their strength. Strength loss increases borehole instability. Younger sediments soften, swell and disperse when mixed with water. Older shales, usually having undergone diagenesis, may remain hard and will not easily disperse into water.

Unfortunately, this does not mean that older shales are easier to drill. Shale instability can result from any or a combination of the following factors.

1. Mechanical Forces
   - Erosion (results in mixed size and shape of cuttings)
   - Pressure differential (*charged* shales resulting in narrow pointed shale splinters)
   - Pipe whip (numerous small mixed shapes from different formations)
   - Surge and swab (results in lost circulation or large quantities of fill and debris)
2. Overburden Pressure
3. Pore Pressure

4. Tectonic Forces
5. Water Adsorption (hydration)

The following problems are caused by these factors.

- Hole enlargement
- Hole cleaning difficulty
- Stuck pipe
- Bridges and fill on trips
- Excessive fluid volume and treating costs
- Increased cement requirements and poor cement jobs
- Well logging problems
- Tight hole
- Increased torque and drag
- Decreased rate of penetration (bit balling)

Table 2-33 and Table 2-34 are summaries of chemical and mechanical stabilization mechanisms.

Table 2-33 Shale Stabilization Mechanisms and Their Applications

Categories	Fluid Type	Stabilization Mechanism	Application
Electrolytes	Fluids utilizing sodium chloride, potassium systems, gypsum and lime fluids, aluminum complex systems (ALPLEX™)	Cation exchange process Li^+, Na^+, K^+, Mg^{++}, Ca^{++}, Al^{+++} Increasing replacement order	Soft, highly-dispersive, hydratable shales, shales high in montmorillonite and large percentages of mixed layers with swelling tendencies.
Polymers	NEW-DRILL®, NEW-DRILL HP, NEW-DRILL PLUS, (hydrolyzed polyacrylamides)	Encapsulation	Soft, fairly high dispersive shales, shales high in montmorillonite and illite with highly expandable mixed layers. Can be used in conjunction with electrolytes for increased inhibition.

NOTE: Application of inhibitive fluids should be preceded by thorough analysis of mineralogy and dispersion testing.

Table 2-33 Shale Stabilization Mechanisms and Their Applications (continued)

Categories	Fluid Type	Stabilization Mechanism	Application
Asphalts and Gilsonites	PROECTOMAGIC® M, SHALE-BOND™	Plug and seal micro-fractures reducing filtrate invasion between bedding planes	Medium hard, moderately dispersive shales with sloughing tendencies. Shale high in inter-layered clays. Sometimes high in illite and chloride
Oil fluids	CARBO-DRILL℠ Systems	Oil external phase, balanced activity of water phase	Highly-dispersive and fractured shales with sloughing tendencies. Hard, brittle, indurated shales in which moderate dispersion exhibits severe sloughing.

NOTE: Application of inhibitive fluids should be preceded by thorough analysis of mineralogy and dispersion testing.

Table 2-34 Mechanically-Induced Borehole Problems and Solutions

Problem	Cause	Indicators	Solutions
Mechanical erosion	Turbulent flow rates. Drillstring geometry. Inadequate rheological properties.	Mixed sizes and shapes of cuttings, excessive lag, hole washout.	Alter rheological properties or reduce pump output to ensure laminar or transitional flow. Reduce drillstring diameter.
Underbalanced hydrostatic pressures	Inadequate fluid weight. Geopressured formations.	Gas cut fluid, excessive splintered or concave cuttings, hole fill after trips.	Raise fluid weight to balance formation pressure.
Pipe whip	Excessive rotary speeds. Drillstring not in tension.	Cuttings - small mixed shapes of different types.	Slow rotary speed. Ensure drillstring is in tension
Swab or surge pressures	Excessive pipe running or pulling speeds. High gel strengths, improper drillstring design.	Loss of circulation, gas, oil, or water intrusions on trips. Large quantities of fill and debris after trips. Improper fluid displacement.	Reduce pipe running or pulling speeds. Condition fluid to reduce gel strengths.

Shale Classifications

Many classification schemes for problem shales have been proposed, but they can be broadly classified by their failure mechanism.

- Hydrating and dispersing shales
- Brittle shales
- Pressured shales
- Stressed shales

Hydrating and Dispersing Shales

When shale is exposed to a water-base drilling fluid without chemistry that provides pore blocking, the filtrate interacts directly with the shale. The results are hydration and pore pressure increase.

Different clay minerals vary widely in their strength and susceptibility to hydration. The most common in drilling are chlorite, kaolinite, illite, and smectite in order of increasing hydration. Smectite usually occurs as a component of a mixed layer clay.

Clay hydration occurs by three mechanisms. *Surface hydration* is the bonding of water molecules to oxygen atoms on the surface of the clay platelets. *Ionic hydration* is the hydration of interlayer cations with surrounding shells of water molecules. *Osmotic hydration* occurs in some clays after they are completely surface and ionically hydrated (usually at 100% humidity). All clays experience hydration, and illite and smectite exhibit varying degrees of ionic hydration. Shale hydration (surface adsorption and osmotic absorption) will result in two distinctly different problems.

1. ***Swelling*** – expansion of the clays due to water uptake
2. ***Dispersion*** – the disintegration of the shale body due to water contact

Since shale includes non-clay minerals such as quartz and feldspar, and a mixture of clays, a mixture of hydration mechanisms will occur in the same piece of rock. The non-clay minerals will not react, the chlorite, kaolinite, and illite will hydrate and create solids problems and smectite will hydrate, swell, and react with ionic solutions.

The level of swelling is controlled by the activity of the ambient solution. When smectite is submersed in water, hydration of the cations on the clay causes the cations to dissociate from its surface, creating an electric imbalance on the clay, in turn causing it to “explode” while imbibing large volumes of water.

Salts with relatively high solubility such as KCl and $CaCl_2$ are highly effective in reducing swelling since this mechanism reduces cation dissociation. In one experiment 3% KCl reduced montmorillonite swelling from 450% to 150% at atmospheric pressure.

Brittle Shales

Brittle shales appear firm and competent but fall to pieces when placed in water. These pieces do not soften or swell in the water. Instability can be caused by either of two mechanisms. The shale can be weakened by the penetration of water along micro-fracture surfaces and bedding planes. The second mechanism results when a small amount of clay is surrounded by a quartz and feldspar matrix. Even slight hydration of the clay will result in a high swelling pressure and make the formation unstable.

Abnormally Pressured Shales

Shales become abnormally pressured when a layer of low permeability compacted clay develops next to a sand and flow from the clay is impeded. In a thick shale formation, the rate of expulsion is not able to keep pace with the rate of compaction and the shale’s pore pressure increases above the normal for a comparable depth of burial.

Abnormally high pressures can also be found in situations where normally pressured formations have been uplifted due to tectonic forces. With the erosion of surface layers, the pore pressure will be high for the depth of burial.

Tectonically Stressed Shales

These shales occur in areas where the earth’s crust has been reshaped by tectonic forces. The shales may have steeply dipping bedding planes. When the forces acting on the formation are relieved by drilling, the shale falls into the hole. These problems are further aggravated if the bedding planes become wet with water or oil. The Atoka and

Springer shales of the American mid-continent are examples of these types of shales.

Pore Pressure Transmission

Recent laboratory work utilizing a specially designed pore pressure transmission (PPT) device has documented the ability of certain drilling fluids to block the invasion of water from the drilling fluid into the shale. The device functions by measuring the increase in pore pressure caused by the exposure of a shale core to various drilling fluids. The unit uses a 1-inch diameter core with a length of up to 3 inches.

This device is a modified 1500 psi Hassler cell. A Hassler cell is a cylinder with a piston inserted in each end. The core is held between the two pistons. A rubber sleeve is placed around the core and the pistons, to seal around the core and prevent flow around the core. The outside of the sleeve is pressured to make a good seal. The faces of the core are exposed to pressurized fluids circulated across the piston faces. This pore pressure transmission unit is used on cores with permeabilities in the range of 0.1 µd to approximately 0.01 µd.

The low pressure side of the core (formation side) is fitted with a 1-liter, 2000 psi, stainless steel accumulator to provide back pressure. The high pressure side of the core is connected to two similar accumulators, one for pore fluid, and one for the test fluid. The pressure in each accumulator is controlled with a manual regulator fed by a 2200 psi nitrogen bottle.

The cell is enclosed in an insulated chamber and the temperature maintained with a 200-watt heater. The heater is controlled with a Dwyer temperature controller driving a Control Concepts phase angle SCR control unit. Temperature control is accurate to ± 0.09°F (± 0.05°C).

Pressure is applied to one end of the core and the flow through the core is measured. The piston on the low pressure side is filled with liquid, and blocked, so an increase in liquid pressure is measured rather than flow. A very small amount of liquid flow through the core will make a large rise in the pressure, making the cell sensitive enough to measure flow through shale. Pressure is plotted as a function of time.

A typical PPT run consists of setting formation pressure at 70 psi, borehole at 180 psi, confining at 700 psi and recording the formation pressure rise vs. time until the formation pressure reaches 180 psi, or the predetermined time limit is reached. The test is stopped at 180 psi, because the pressure rise rate becomes asymptotically slower as the pressure drop across the core approaches zero. However, since the permeability of the cores vary, the pressure rise with synthetic pore fluid is first measured to serve as a baseline to which the drilling fluid pressure rise is compared.

For the pore fluid and drilling fluid runs to be comparable, the initial conditions for both runs must be the same. This initial condition is a fully saturated core with a linear pressure distribution along its length varying from 180 psi at the borehole end to 75 psi at the formation end. When borehole pressure is first applied to the core, the pressure is 180 psi only at the core face, the pressure inside the core is still atmospheric. Over time (several hours) the pressure slowly invades the core, until a linear pressure distribution is established along the core length from 180 to 75 psi. The presence of this distribution is detected by a pressure rise on the formation side. So the system is initialized by applying the pressures with synthetic pore fluid and waiting until formation pressure begins to rise.

1. The core is put in the cell and brought up to pressure and temperature with 2% sea salt on both upstream and downstream ends.
2. The sea salt solution is allowed to flow through the core and the downstream pressure increase is recorded.
3. The downstream pressure is lowered back to 75 psi.
4. Drilling fluid is flowed across the upstream end of the core at constant 180 psi pressure.
5. The downstream pressure rise is again recorded.
6. The pressure rise with drilling fluid is compared to the pressure rise with salt water

Figure 2-9 shows the effect of AQUA-DRILL^{SM} glycols in controlling pressure transmission. AQUA-COL™ D, at a test temperature of 120°F [49°C], did not stop pressure transmission because AQUA-COL D has a cloud point of 130°F [54°C], and does not block pore passages when soluble. At 158°F [70°C], the cloud point of the

AQUA-COL™ D was exceeded causing it to come out of solution to block entrance of fluid into the core. The pressure leveled out with no further increase.

Figure 2-9 AQUA-COL PPT Results

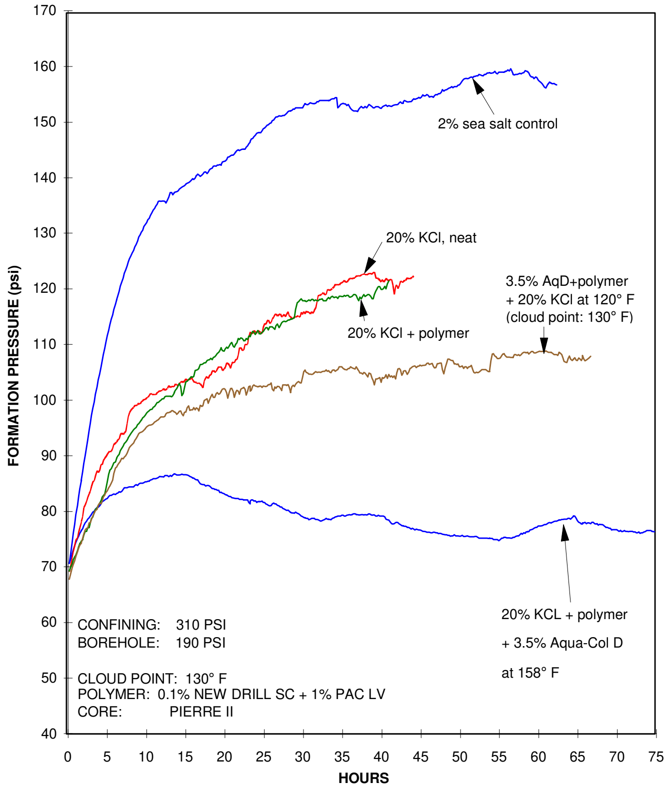
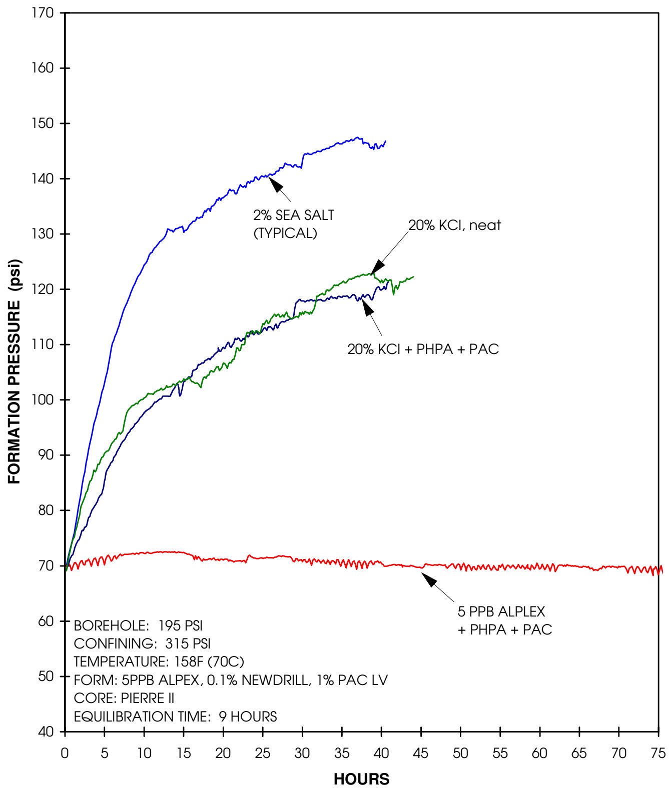


Figure 2-10 illustrates how the ALPLEX™ system was very effective in blocking fluid flow into the core matrix. The 2% sea salt fluid with a 5 lb/bbl treatment of ALPLEX showed no pressure rise with time. This blockage of fluid entering the wellbore may be explained by the formation of a fine colloidal precipitate of hydrous alumina oxides on the face of the core.

Figure 2-10 5 ppb ALPLEX PPT Results



In both examples the 2% sea salt formation fluid shows rapid pressure transmission through the shale. Other tests with 20% KCl and 20% KCl polymer fluids indicate the effective decrease of pore pressure transmission by the fluids because of increased viscosity and the potassium ion. This represents the fluid entering the well bore at a reduced rate. These test results have illustrated that AQUA-COL™ and ALPLEX™ will plug or block the invasion of fluid into the core. With no migration of fluid, the core remains intact and free of hydration forces or other chemical reactions.

Loss of Circulation

Causes

Fractured Formations

Natural fractures may be indicated when losses occur during or immediately subsequent to rough drilling or sudden formation change.

Induced fractures are indicated where losses occur while tripping pipe, breaking circulation, or raising fluid weights. Causes include exceeding the fracture gradient with excessive fluid weights or high surge pressures and equivalent circulating densities (ECD).

Highly-Permeable Formations

1. Formation types – Massive sands, pea gravel, shell beds, or reef deposits
2. Indicators – Continuous gradual seepage losses. Partial returns. (Rate-of-loss is dependent on the degree of permeability.)

Highly-Porous Formations

1. Formation types – Sands, gravel beds, reef deposits
2. Indicators – Partial loss of returns which may develop slowly and increase with penetration.

Cavernous and Vugular Formations

1. Formation types – Limestones, dolomite, chalk, and other formations with secondary porosity
2. Indicators – Sudden and severe to complete loss of returns which may be accompanied by sudden erratic rates of penetration. Formations of this nature are generally predictable in areas with significant drilling histories.

Preventative Measures

1. Use of minimum fluid densities as dictated by formation pressures and borehole stability.
2. Evaluate area well data to determine proper fluid weights and casing placement. Establish formation integrity with pressure test at the most recent casing depth.

3. Monitor and control rheologies to minimize swab/surge pressures, annular friction loss (ECD), and control pipe running speeds.
4. Maintain thermally-stable rheologies to avoid high temperature gelation. Breaking circulation in stages while tripping is advisable when gelation is evident. Utilize standpipe choke (if available) to break circulation with a gradual pressure increase.
5. Minimize annular restrictions.
    - Optimize bit hydraulics and/or use of additives such as MD or BIO-DRILL™ 1402 to minimize bit and drillstring balling.
    - Control rates of penetration to avoid excessive solids loading in the annulus.
    - Avoid excessive wallcake development by reducing filtration rates.
    - Use of inhibitive fluids such as NEW-DRILL® ALPLEX™, CARBO-DRILL℠, potassium-base and calcium-base fluids can provide protection against swelling and sticky shale.

Remedial Procedures for Loss Circulation

Seepage Loss (Permeable Formations)

1. Treat system with fine lost circulation material such as MIL-PLUG®, MILMICA®, CHEK-LOSS®, W.O.™ 30 (fine and coarse), or SOLUFLAKE®.
2. Accompany LCM treatments with additions of a viscosifier such as MILGEL® to improve particle-size distribution.
3. Avoid excessive circulation rates and/or penetration rates to minimize ECD and solids loading of the annulus.

Partial Loss (Highly-Porous or Fractured Formations)

1. Treat system with various sizes of LCM such as MIL-PLUG, MIL-CEDAR FIBER™, and CHEK-LOSS. Mixtures of different shapes are often quite effective.

2. For severe losses, spot pill opposite the loss zone utilizing 30 to 40 lb$_m$/bbl of various types of LCM. Pull up into casing and allow 6 to 8 hours.
3. Squeeze the zone with an high-filtration slurry such as DIASEAL® M (see Table 2-35). The addition of 10 to 20 lb$_m$/bbl of CHEK-LOSS® will generally improve chances of success. When applying high-filtration slurries, squeeze slowly (½ to 1½ lb$_m$/min) with pressure not exceeding 50 to 1 00 psi. Final squeeze pressure should not exceed 0.1 psi/ft of depth.

Total Loss (Caverns, Vugs, or Induced Fractures)

1. Cement loss zone. Neat or bentonite cement for 14.5 to 15.5 lb$_m$/gal. Gilsonite cement for densities below 14.5 lb$_m$/gal.
2. Utilize soft plugs such as diesel oil-bentonite cement or diesel oil-bentonite gunk squeeze slurry (see Table 2-36).
3. Drill blind without returns until loss zone can be cased off.
4. Drill with air, stiff foam, or aerated fluid.

Preparing & Using Lost-Circulation Pills in Water-Base Systems

Note: *When water-absorbing materials such as CHEK-LOSS are employed, observe the effect of LCM on viscosity prior to adding the full amount of DIASEAL M.*

Example: 100 bbl of 14 lb$_m$/gal DIASEAL M slurry requires 68 sacks DIASEAL M, 290 sacks MIL-BAR®, 70 bbl water, and CHEK-LOSS, if desired.

Table 2-35 Formulation for Preparing 1 bbl DIASEAL® M, Weighted Slurry with Freshwater, Baywater, or Seawater

Density (lb$_m$/gal)	DIASEAL M (lb$_m$)	DIASEAL M (sacks)	MIL-BAR® (sacks)	Water (bbl)
9	50	1.00	0.0	0.87
10	50	1.00	0.6	0.84
11	47	0.94	1.2	0.80
12	42	0.84	1.8	0.77
13	38	0.76	2.3	0.74
14	34	0.68	2.9	0.70
15	31	0.62	3.5	0.67
16	28	0.56	4.0	0.63
17	25	0.50	4.6	0.60
18	22	0.44	5.2	0.56
19	17	0.34	5.8	0.52

Table 2-36 Soft Plug Formulations (Total Loss of Circulation)

Diesel Oil-Bentonite Cement Squeeze (100 bbl)

- 154 sacks (100 lb$_m$/sack) cement
- 154 sacks MILGEL®
- 72 bbl diesel oil

Diesel Oil-Bentonite Gunk Squeeze

- 4 sacks (100 lb$_m$/sack) MILGEL
- 1 bbl diesel oil (final volume 1.42 bbl)

Squeeze Procedure

1. Locate loss zone (temperature or radioactive survey) and run in hole open ended.
2. Mix slurry volume equivalent to or greater than hole vol below loss zone.
3. Precede slurry with 5 bbl of diesel oil and pump slurry t Follow slurry with 5 bbl diesel.

4. When the slurry exits drillstring, close annular preventers and pump fluid into annulus at 2 bbl/min while displacing the slurry from the drillpipe at 4 bbl/min.
5. After displacing ½ the slurry from drillstring, reduce pump rates to 1 bbl/min on the annulus and 2 bbl/min on the drillpipe.
6. After displacing ¾ of the slurry from drillstring, attempt a "hesitation squeeze pressure" of 100 to 500 psi.
7. Under displace slurry leaving 1 bbl in drillstring, pull out of hole and allow 8 to 10 hours set time.

Drillstring Sticking

Causes of Stuck Pipe

1. Differential Pressure (Wall Sticking)
2. Mechanical
    - Key seating
    - Formation-related wellbore instability
    - Wellbore geometry (deviation and ledges)
    - Inadequate hole cleaning
    - Junk in hole or collapsed casing
    - Cement related

Preventative and Control Measures

1. Differential Pressure Sticking
    - Control fluid densities as low as practical
    - Control filtration rate to produce a thin, compressible wallcake
    - Control drilled solids as low as possible
    - Control drill to avoid overloading annulus
    - Utilize friction-reducing additives

Table 2-37 Materials Utilized to Reduce Friction Coefficient and Minimize Wall Sticking

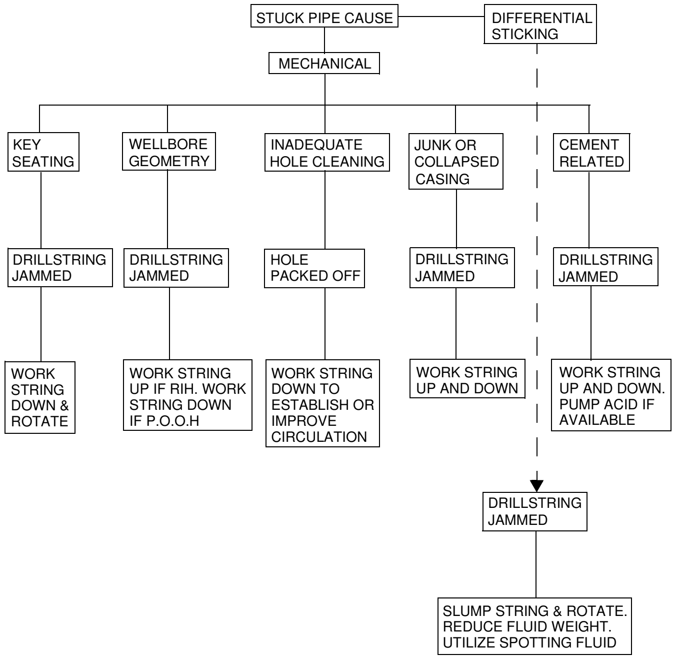
Product	Initial Recommended Treatments	Maintenance
LUBRI-FILM®	4 lb_m/bbl	Dependent upon dilution rates
MIL-LUBE™	0.5% - 2.0%	Dependent upon dilution rates
AQUA-MAGIC™	1.0% - 8.0%	Dependent upon dilution rates

2. Mechanical
    - Key seating
        a. Control hole deviation
        b. Ensure drillstring is in tension
        c. Utilize string reamers and stabilizers
    - Formation-related wellbore instability is generally associated with "tight hole" conditions. Improvement in hole conditions can be seen with optimization of fluid properties and the use of appropriate inhibitive additives and fluid systems.
    - Inadequate hole cleaning can be improved by altering fluid rheologies and pump rates.

Remedial Procedures for Stuck Pipe

The "free-point" may be determined from electric logging or pipe stretch calculations found in Chapter 5. Recommended freeing methods are outlined in Figure 2-11.

Figure 2-11 Stuck Pipe Causes and Recommended Freeing Methods



Spotting Fluids

Baker Hughes INTEQ offers a variety of spotting fluids which are designed for use in every drilling environment. These fluids may be used in weighted or unweighted form. The success of spotting fluids is time related. Prompt placement of spotting fluids will improve chances of freeing drillstring. Adequate material and mixing facilities should be available on rig. Table 2-38, Table 2-39, and Table 2-40 contain BLACK MAGIC® SFT, BIO-SPOT® II, and MIL-SPOT™ 2 material requirements.

1. BLACK MAGIC® – Premium-grade asphalt compound in diesel oil (liquid).
2. BLACK MAGIC LT – Premium-grade asphalt compound in low-toxicity mineral oil (liquid).
3. BLACK MAGIC SFT (Sacked Fishing Tools) – A dry mixture of air-blown asphalt, lime, and emulsifiers available in powdered form. Conveniently stored at rigsite and mixed with either low-toxicity mineral oil or #2 diesel.
4. BIO-SPOT® II – A non-toxic, oil-free, water-soluble spotting fluid concentrate. BIO-SPOT II can be mixed readily. Recommended for use in environmentally-sensitive areas.
5. MIL-SPOT™ 2[1] – A liquid blend of emulsifiers, wetting agents, and gellants. For use in #2 diesel or low-toxicity mineral oils.

Table 2-38 BLACK MAGIC SFT Material Requirements (per 100 bbl)

Density (lb_m/gal)	Base Oil* (bbl)	BLACK MAGIC® SFT (sacks)	Water (bbl)	MIL-BAR® (sacks)
unwtd.	70	136	12	0
10	64	124	11	135
12	62	113	7	240
14	57	102	6	345
16	54	91	3	455
18	49	81	3	560

*Base Oil: Low-toxicity mineral oil or #2 diesel (140°F aniline point minimum).

BLACK MAGIC Mixing Procedure

1. Clean mixing pits and flush pumps.
2. Add mixing oil as per chart.
3. Add BLACK MAGIC SFT through hopper with agitation.

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[1] Available through Baker Hughes INTEQ international operations.

4. Add water and agitate to a smooth blend.
5. Add MIL-BAR® and agitate to a smooth blend.
6. To increase viscosity, add more BLACK MAGIC SFT.
7. To reduce viscosity, add oil.

Table 2-39 BIO-SPOT II Spotting Fluid Material Requirements (per 100 bbl)

Density (lb_m/gal)	BIO-SPOT® II (bbl)	BIO-SPOT II THINNER (bbl)	MIL-BAR (sacks)
8.9	100	0	0
9.5	97	0	34
10.0	95	0	62
10.5	93	0	90
11.0	91	0	117
11.5	89	0	145
12.0	88	0	173
12.5	86	0	201
13.0	84	0	229
13.5	82	0	257
14.0	80	0	285
14.5	73	5	314
15.0	66	10	342
15.5	59	15	371
16.0	52	20	400
16.5	45	25	428
17.0	38	30	457
17.5	31	35	486
18.0	25	40	515
18.5	18	45	543
19.0	11	50	572

Recommended Treatment

Spot at least enough BIO-SPOT® II spotting fluid to cover the entire stuck pipe interval, and preferably no less than 100 bbl.

BIO-SPOT Mixing Procedure

1. Thoroughly clean mixing pit. Flush pump and mixing lines with 20% sodium chloride, preferably, or seawater and drain, if possible, to minimize dilution of the BIO-SPOT® II spotting fluid.
2. Add correct volume of BIO-SPOT II concentrate for desired spot volume and density (see Table 2-39). Add BIO-SPOT II THINNER as necessary for densities greater than 14.0 lb_m/gal to reduce viscosity of higher weight spots. For bottomhole temperatures in excess of 300°F, additional BIO-SPOT II THINNER may be needed.
3. Agitate until thoroughly blended.
4. Add MIL-BAR® to the desired density and mix until thoroughly blended and smooth.
5. Weighted spot at this point should be pumpable yet have sufficient body to suspend weight material. If spot is too viscous, add additional BIO-SPOT II THINNER and MIL-BAR as necessary.
6. Pump spot at normal pumping rate and follow industry-accepted procedures using spotting fluids.

MIL-SPOT Mixing Procedure

1. Prior to mixing, thoroughly clean a slug tank with drill-water or seawater and flush out mixing lines.
2. Fill the slug tank with the required amount of oil as determined from Table 2-40.
3. Add the required amount of MIL-SPOT™ 2 spotting fluid, followed by the required amount of seawater or drillwater.
4. Add MIL-BAR to achieve desired fluid weight. All materials can be mixed as fast as required.
5. Barites vary in quality. Different barites, especially flotation varieties, can have a marked effect on rheology. Pilot test if barite is poor quality.

Table 2-40 MIL-SPOT® 2 Material Requirements (per 50 bbl)[1]

Fluid Weight (lb_m/bbl)	Diesel Volume (bbl)	MIL-SPOT 2 (55-gal drum)	Seawater or Drillwater (bbl)	MIL-BAR® (lb_m)
8	29.0	4	14.6	1,925
10	26.7	4	13.7	6,600
12	26.4	4	10.5	11,750
14	26.0	4	6.9	17,650
16	24.9	4	4.5	22,750
18	23.4	4	2.5	27,900

[1]**NOTES**:

1. The relative volumes of oil/water must be adhered to for each weight.
2. Obtaining fluid weights between those listed in Table 2-40 is a simple case of extrapolation.
3. All the fluids are designed for yield values of 16 $lb_f/100\ ft^2$. Increasing oil content decreases rheology. Increasing water content increases rheology but also increases tendency of solids to become water-wet.
4. Employ maximum agitation in the slug pit when mixing barite.

Chapter 3

Oil- and Synthetic-Base Drilling Fluids

Advantages	Disadvantages
Shale stability and inhibition	High initial cost per barrel
Temperature stability	Mechanical shear required
Lubricity	Reduced kick detection
Resistance to chemical contamination	Pollution control required
Gauge hole in evaporative formations	High cost of lost circulation
Solids tolerance	Disposal problems
Reduced production damage	Solids control equipment is limited to shakers, fluid cleaners, and centrifuges.
Reduced tendency for stuck pipe	Hole cleaning
Reduced fluid density drilling	Rig cleanliness
Re-use	Special skin care for personnel may be required
Reduced cement cost	Hazardous vapors
High penetration rate	Effect on rubber
Flexibility	Fire hazard
Reduction of stress fatigue	Special logging tools required
Reduced corrosion	Gas stripping

Introduction

Because the advantages listed above frequently outweigh the disadvantages, oil- and synthetic-base fluids continue to be used in difficult drilling environments and in special applications. The fluids are most commonly prepared as emulsions of brine water in an appropriate oil- or synthetic-base fluid.

In the past, the most commonly used oils for drilling fluids were No. 2 diesel, and low-aromatic-content, low-toxicity mineral oils. Crude oil has been used; however, due to safety, health and environmental issues, its use is now rare. CARBO-DRILL^{SM} systems use diesel and mineral oil as the base fluid.

The development of systems that use synthetic fluids as a replacement for diesel and mineral oil have eliminated many of the environmental, health and safety issues traditionally associated with oil-base drilling fluids. These synthetic-base fluids have found application in many offshore areas where the discharge of fluid and cuttings from traditional oil muds are restricted. The SYN-TEQ™ system, prepared from various environmentally friendly base fluids, is an effective and environmentally acceptable substitute for the CARBO-DRILL system.

The following sections describe the preparation and maintenance of the CARBO-DRILL and SYN-TEQ fluid systems.

Formulation Disclaimer

Due to variations in the internal and external phases of oil-base and synthetic-base fluids, specific fluid formulations should be developed by pilot testing for each phase combination at the ANTICIPATED OPERATING CONDITIONS. The table formulations contained herein are generic and should be modified as needed to meet operational needs.

Table 3-1 Typical Oil / Synthetic Properties

	Density at 60°F (15°C) (g/ml)	Initial Boiling Point	Final Boiling Point	Flash Point	Aniline Point	Aromatic Content (%v/v)	Viscosity at 104°F (40°C) (cSt)
Diesel	0.840	383°F 195°C	734°F 390°C	149°F 65°C	154°F 68°C	25	3.4
Exxon ESCAID 110	0.790	406°F 208°C	468°F 242°C	174°F 79°C	169°F 76°C	< 0.5	1.6
Total HDF200	0.814	446°F 230°C	617°F 325°C	221°F 105°C	187°F 86°C	6.0	3.2
Conoco LVT200	0.806	441°F 227°C	482°F 250°C	200°F 93°C	166°F 74°C	< 1	2.1
ISO-TEQ	0.792	—	—	277°F 137°C	—	None	< 3.6
PAO, 6CST	0.797	—	—	311°F 155°C	218°F 103°C	None	5.5
PARA-TEQ™	0.765	419°F 215°C	500°F 260°C	212°F 100°C	—	—	1.8
Ester	0.850	—	—	> 302°F > 150°C	—	None	5.0 – 6.0

CARBO-DRILL Systems

1. **CARBO-TEC®**– A complete invert emulsion system generally used in extremely harsh environments where greater emulsion stability and higher tolerance to contaminants are required.
2. **CARBO-FAST℠** – A low colloid, relaxed filtrate system generally used in less harsh environments where rapid penetration rates are desired.
3. **CARBO-CORE™** – Prepared without water or brine. Generally used for coring purposes, but can be adapted for use as an all oil drilling fluid.

To reduce wear on rubber gaskets, seals, and pipe rubbers, oil with an aniline point greater than 140°F (60°C) is recommended. Generally the higher the aniline point, the lower the aromatic content. To minimize flammability, a flash point greater than 180°F (82°C) is advised.

Hydrocarbon oils used in oil-base fluids are generally more viscous than water. The wide range in the viscosity (see Table 3-1) of the various oils used as the continuous phase of oil-base and synthetic-base fluids will affect certain characteristics of the fluids, notably the rheological and filtration control properties.

CARBO-TEC System Products

1. **CARBO-TEC®** is an anionic, liquid emulsifier. Lime hydrate [$Ca(OH)_2$] or quicklime (CaO) must be added to the system to activate the emulsifier. System treatment levels vary from 0.6 to 1.7 gal/bbl. Lime is added at 5 lb_m per gallon of CARBO-TEC.
2. **CARBO-MUL® HT** is a nonionic to slightly cationic emulsifier (displaying amphoteric tendencies). It provides emulsion stability and is a primary oil wetter which assists in the dispersion of incorporated solids. This emulsifier is a reacted amide and does not need lime to be activated. Treatment levels will vary from 0.1 to 1.0 gal/bbl.
3. **CARBO-TROL®** is a powdered asphalt filtration-control additive. If high concentrations (> 40 lb_m/bbl) are used, it will also function as a viscosifier. It functions effectively at temperatures above 400°F (190°C). Treatment levels are normally 2 to 10 lb_m/bbl.
4. **CARBO-TROL® A-9** is an amine-treated lignite used for filtration control when asphaltic materials are not desirable. This product is effective at temperatures up to 300°F (149°C) or higher. Treatment levels normally vary from 5 to 10 lb_m/bbl. Do not use at high temperatures in acid gas (i.e., H_2S, CO_2) environments.
5. **CARBO-TROL® HT** is a high-temperature softening-point gilsonite used to improve filtration control. Treatments of 2.0 to 10.0 lb_m/bbl (5.7 to 28.5 kg/m^3) should be adequate for most applications.
6. **CARBO-VIS™** is an organophilic bentonite used for rheology modification and gel strength, as well as some filtration control. The product is effective to temperatures above 350°F (177°C). Treatment concentrations will vary depending on the type of oil, but generally 1 to 5 lb_m/bbl are adequate.
7. **CARBO-GEL®** is an organophilic hectorite which provides rheological structure, gel strengths, and assists in filtration control. This product is effective above 400°F (190°C). Concentration levels will vary depending on the type of oil, but generally 1 to 5 lb_m/bbl will be adequate.

Table 3-2, Table 3-3, and Table 3-4 show typical CARBO-TEC system formulations.

CARBO-FAST System Products

1. **CARBO-MUL® HT** is the only emulsifier and oil wetting agent used in the low-colloid, relaxed-filtrate CARBO-FAST℠ system. Concentration levels will vary from 0.5 to 0.75 gal/bbl.
2. **CARBO-VIS™**, as described in the CARBO-TEC system, can be used in concentrations of 1 to 5 lb_m/bbl.
3. **CARBO-GEL®** is considered the premier viscosifier and can be substituted for CARBO-VIS in 1 to 5 lb_m/bbl concentrations, and may require a polar activator.

Table 3-5, Table 3-6, and Table 3-7 contain typical CARBO-FAST system formulations.

CARBO-CORE System

Native State Drilling and Coring Fluids

The CARBO-CORE^{SM} system is a no-water-added oil-base fluid system used as a native state coring and drilling fluid. It is used whenever potential invasion of water, or oil filtrate with surfactants, into producing reservoirs must be avoided. The CARBO-CORE system is temperature stable, even after contamination with water. Should contamination be severe, it can be converted to a CARBO-FAST^{SM} or CARBO-TEC$^{®}$ system.

A drilling fluid that minimizes changes in formation wettability and water saturation in a producing reservoir will result in maximum permeability and oil production. Invasion of water filtrate into producing reservoirs can alter connate water saturation. Invasion of oil filtrate, containing strong surfactants, can possibly alter the wettability characteristics of the formation. A naturally water-wet sand may become oil-wet if the filtrate contains strong surfactants.

The alteration of water saturation and/or wettability characteristics can result in errors in predicting and evaluating reservoir performance based on core data. In some cases, these actions may also decrease production after the well is completed.

No-water-added oil-base coring fluids have been used previously to retrieve unaltered cores for laboratory analysis. These cores are used to better define water saturation, connate water salinities, and oil water contacts. Cores that are recovered are also used to determine reservoir permeability and porosity as well as for laboratory flow tests to better define the reservoir characteristics.

Lease crude has been used, and is preferable as a drilling or coring fluid when unaltered cores are required. However, density requirements, or the lease crude characteristics, may make its use impracticable. Normally, CARBO-CORE is prepared with minimum surfactants and a near zero water content, using mineral or diesel oil.

Components

Base Oils

CARBO-CORE fluids may be prepared with lease crude, No. 1 diesel, No. 2 diesel, mineral oil, or a combination of oils to meet individual requirements. If lease crude is used, it must be free of emulsion breakers and filming amine corrosion inhibitors, which can alter wettability characteristics. Lease crude must also have an aniline and flash point above the desired minimum. High viscosity lease crude may be blended with mineral oil or diesel to the desired viscosity range. No. 1 diesel oil or mineral oil is more desirable than No. 2 diesel, since No. 2 diesel may contain additives that can cause formation contamination. Pilot testing is recommended prior to the use of various oils due to their solubility and viscosity differences.

Water Phase

CARBO-CORE^{SM} systems are prepared without water. However, 2% to 5% water may be incorporated during displacement of a water-base fluid. If the water content is in excess of 5% to 10%, depending upon the type of shale and/or cores being drilled, the system should be displaced, diluted, or converted to a standard controlled activity CARBO-DRILL system.

Mixing Procedures

Because water content is contrary to the design of the CARBO-CORE system, special care must be taken when mixing and displacing the system.

The mixing tank should be clean and all lines flushed with diesel or a used CARBO-DRILL^{SM} system which is then discarded. Pump the required amount of base oil add the required amount of viscosifiers. The application of heat, up to 180°F (82°C), will increase dispersion of product, evaporate water, decrease mixing time, and result in a more stable system overall. The calculated amount of CARBO-TROL$^{®}$ HT should be added as quickly as possible, based upon the mixing system available.

After a satisfactory dispersion and adequate viscosity has been achieved, weight material may be added to obtain the desired density. If additional viscosity is necessary, *small* additions of viscosifiers may be used.

Displacement

Because a low to zero water content is desired, the displacement procedure can have a tremendous effect upon the overall system performance. Ideally, casing should be run and the cement plug be pumped with the CARBO-CORE^{SM} fluid.

If this is not possible, displacement prior to drilling out of casing is highly recommended. Displacement at high flow rates while rotating and reciprocating the drillpipe will minimize water contamination. In situations where water content *must* be maintained near zero, displacements have been made using a standard CARBO-DRILL^{SM} oil-base fluid to displace the water-base fluid, followed by the CARBO-CORE system. For further information, see **Displacement Procedures**.

Water Contamination

The CARBO-CORE system has proven to be temperature stable even after contamination with water, as indicated in Figure 3-1. Because the rate of osmotic transfer of water from the fluid to the shale increases as the water content increases, small quantities of water should not greatly affect the stability of the shale. However, should water contamination exceed 5%, it is recommended to dilute with oil, displace the system with new fluid, or simply convert the CARBO-CORE to a conventional CARBO-DRILL system. This can be accomplished with the addition of calcium chloride to reduce the activity of the water phase to a desired range.

Further additions of CARBO-MUL® HT and CARBO-TEC® will maintain fluid stability as the water content increases.

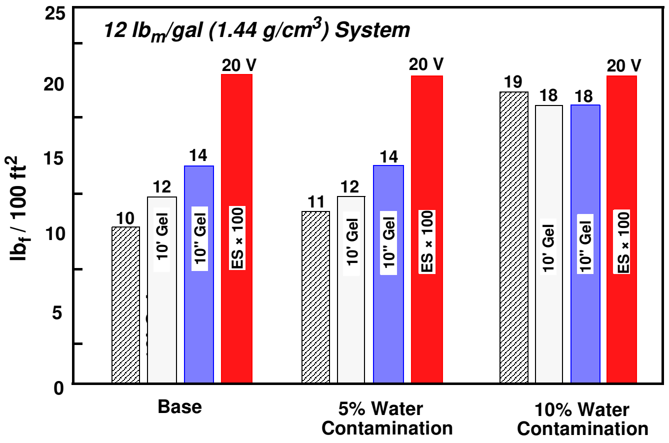
CARBO-CORE System Products

1. **CARBO-TEC®** concentrations will vary from 0.6 to 1.7 gal/bbl. Lime at 5 lb$_m$/gal is required to activate the emulsifier.

Note: *CARBO-CORE may be converted to CARBO-DRILL by additions of CARBO-MUL HT which may affect the wettability of the formation.*

2. **CARBO-GEL®** concentrations should be between 5 to 10 lb$_m$/bbl. Whenever possible, rheological properties should be controlled with CARBO-GEL instead of CARBO-VIS.

Figure 3-1 CARBO-CORE^{SM} Typical Flow Properties



3. **CARBO-TROL® HT** is used for filtration control. Treatment levels should be between 5 and 15 lb$_m$/bbl.

CARBO-DRILL Supplemental Products

1. **DFE 418** is an oil-soluble imidazoline used as an emulsifier and wetting agent to improve the temperature and solids tolerance of the CARBO-DRILL^{SM} systems. Treatments levels will vary between 0.1 to 1.0 gal/bbl.
2. **OMNI-COTE™** is an oil-soluble sulfonate surfactant used as a wetting agent to promote rapid oil wetting of MIL-BAR®, DENSIMIX®, and drill solids. Concentrations should vary between 0.1 to 0.25 gal/bbl.

Note: *OMNI-COTE can rapidly decrease rheological properties of an oil-base fluid. Therefore, care should be taken when treating with this product.*

3. ****CARBO-MIX™** is a high-activity anionic emulsifier and is used almost exclusively with the higher-water-content fluids used in the North Sea. Treatment levels vary between 0.25 and 1.5 gal/bbl.

4. **OMNI-PLEX™** is an elastomeric viscosifier designed to supplement CARBO-GEL and CARBO-VIS (as an extender). This product can be used to increase low rpm readings in a wide range of temperatures and improves rheological properties at temperatures in excess of 450°F (232°C). Treatment levels vary from 0.05 to 0.25 lb_m/bbl. This product may be used as a polar activator in the CARBO-CORE system.
5. ****6-UP™** is a liquid rheology modifier used to increase low rpm values without increasing plastic viscosity. Treatment levels vary between 0.1 and 0.4 gal/bbl.
6. **SA-58™** is a blend of fatty acids that will increase the viscosity and gel strength of an oil-base fluid during preparation and transport. The viscosity building characteristics of SA-58 will be reduced with shear and higher temperature, therefore, continued use at the well site is not recommended. Treatment levels will vary between 0.25 and 0.75 lb_m/bbl.

All of the CARBO-DRILL℠ products are compatible and can be interchanged to meet wellbore requirements. Laboratory and field pilot testing are recommended if formulations and concentrations are to be varied.

Table 3-8 contains typical CARBO-CORE system formulations.

*** These products are available only through Baker Hughes INTEQ*

The SYN-TEQ Systems

Introduction

With the recent advent of synthetic drilling fluids for application offshore and in other environmentally sensitive areas, SYN-TEQ℠ has become an effective, environmentally acceptable substitute for traditional diesel and mineral oil based drilling fluids. Environmental regulations around the world continue to develop in different directions, each dependent on local regulatory policies. Therefore, the SYN-TEQ system offers flexibility in the user's choice of base fluids. SYN-TEQ can be formulated with either ISO-TEQ™ (isomerized olefin) or PARA-TEQ™ (linear paraffin). Because environmental regulations are in a constant state of flux, it is advisable to check on current policy and product offering for each operational area of interest at the time of need to take advantage of the most up-to-date product offering.

SYN-TEQ Systems

There are two SYN-TEQ℠ systems. The SYN-CORE℠ system is a special application of the SYN-TEQ system prepared without water/brine. Although the SYN-CORE system is generally used for coring purposes, it can be adapted for use as a conventional all synthetic drilling fluid.

The SYN-TEQ system is comparable to the CARBO-DRILL℠ system with the synthetic ISO-TEQ™ or PARA-TEQ™ base fluids replacing the oil. Emulsions like those found in CARBO-DRILL® fluids are similarly prepared.

SYN-TEQ System Products

The SYN-TEQ system offers flexibility in fluid formulation for optimized performance. Table 3-9, Table 3-10, Table 3-11 contain typical SYN-TEQ fluid formulations. The "core" SYN-TEQ system is comprised of the following products.

1. **ISO-TEQ™** – The external phase, non-toxic, biodegradable, isomerized olefin base fluid that is void of any priority pollutants.

2. **PARA-TEQ™** – Alternative external phase comprised of a blend of linear paraffins. PARA-TEQ™ is biodegradable and non-toxic.

3. **OMNI-TEC™** – The system's anionic emulsifier. It is compatible with a wide range of internal-phase salinities. It provides greater filtration control in high temperature applications. OMNI-TEC concentrations will vary between 0.25 and 0.5 gal/bbl. The addition of 5 lb$_m$ of lime per gal of OMNI-TEC is required to activate the emulsifier.

4. **OMNI-MUL™** – The non-ionic emulsifier and secondary wetting agent that controls system rheology while weighting up. OMNI-MUL concentrations will vary between 1.0 and 3.0 gal/bbl, depending on the application. Concentrations will be affected by several factors including amount of solids incorporated into the system, and temperature.

5. **OMNI-MIX™** – A supplemental anionic emulsifier providing additional filtration control and preventing water-wet solids.

6. **CARBO-TROL® HT** – Used for filtration control. Treatment levels should be between 5 and 10 lb$_m$/bbl.

7. **OMNI-TROL™** – A high-temperature amine-treated lignite product which effectively controls filtration to temperatures up to 300°F (149°C).

8. **CARBO-GEL®** – An organophilic clay viscosifier providing additional rheological and filtration control as well as solids suspension. CARBO-GEL concentrations should be between 5 and 10 lb$_m$/bbl.

9. **MIL-LIME™** – Delivers alkalinity control and activation of the OMNI-TEC™ emulsifier.

SYN-CORE System Products

1. **OMNI-TEC™** – The system's anionic emulsifier. It is compatible with a wide range of internal-phase salinities. It provides greater stability in high temperature applications. OMNI-TEC concentrations will vary between 0.6 and 1.7 gal/bbl with the addition of 5 lb$_m$/gal of lime to activate the product as needed.

Note: *SYN-CORE℠ may be converted to SYN-TEQ℠ by additions of OMNI-MUL which may affect the wettability of the formation.*

2. **CARBO-GEL®** – An organophilic clay viscosifier providing additional rheological and filtration control as well as solids suspension. CARBO-GEL concentrations should be between 5 and 10 lb$_m$/bbl.

3. **CARBO-TROL® HT** – A high softening point gilsonite filtration control agent effective in high-temperature applications and having minimal effects on rheological properties. Treatment levels are typically between 5.0 and 10 lb$_m$/bbl.

Table 3-12 contains typical SYN-CORE fluid formulations.

SYN-TEQ Supplemental Products

1. **OMNI-COTE™** – Controls rheological increases caused by the addition of drill solids and facilitates the oil-wetting of solids. Concentrations vary between 0.1 and 0.25 gal/bbl.

2. **OMNI-PLEX™** – An elastomeric viscosifier designed to supplement CARBO-GEL® and CARBO-VIS™ (as an extender). This product can be used to increase low rpm readings in a wide range of temperatures and has successfully improved rheological properties at temperatures in excess of 450°F (232°C). Treatment levels should be between 0.25 and 0.75 gal/bbl.

Plant/Field Mixing Procedures

Recommended Formulations

This section contains the recommended formulation tables for the most commonly prepared CARBO-DRILL℠ and SYN-TEQ℠ fluids. These formulations are based on laboratory tests. Actual field concentrations may vary depending on the wellbore requirements. It is strongly advised that the recommended formulations be followed when building a fluid in a mixing plant.

Note: *Due to variations in the internal and external phases of oil-base and synthetic-base fluids, specific fluid formulations should be developed by pilot testing for each phase combination at the* ***anticipated operating conditions****. The table formulations contained herein are generic and should be modified as needed to meet operational needs.*

Note: *In the tables to follow,* ***Brine*** *= 250,000 ppm* $CaCl_2$ *water.*

Note: *The volumes and densities are accurate to ± 1%. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL/SYN-TEQ.*

1. Measure the appropriate amount of oil, ISO-TEQ™, or PARA-TEQ™ into the mixing tank and circulate the base fluid through the hopper and fluid guns.
2. Add the selected organophilic clay and lime slowly through the hopper. Mix the suspension until it is well dispersed.
3. Add the proper amount of CARBO-MUL® HT/ OMNI-MUL™ through the hopper. Mix until the fluid appears homogeneous. This should take approximately 30 minutes.

4. For CARBO-TEC® formulations, add the appropriate amount of CARBO-TEC through the hopper and allow to mix for a minimum of 45 minutes.
5. Add brine water slowly through the hopper over a three to four hour period and allow to mix for 45 minutes.
6. Add the appropriate amount of filtration control additive through the hopper and allow to mix for a minimum of 45 minutes.

Note: *CARBO-TROL®* ***should not*** *be used in SYN-TEQ℠ formulations.*

7. Add the proper amount of MIL-BAR® to attain desired fluid weight. To insure proper wetting and dispersion, slow the additions of MIL-BAR as the fluid density increases. Periodically, check the yield point, gel strength, and emulsion stability to ensure proper barite suspension and that a stable emulsion is being formed. Slower additions of MIL-BAR may be necessary if inadequate shear exists and emulsion stability is not stable or is decreasing.
8. Add supplemental rheological modifiers as needed.
9. It may be necessary to add SA-58™ prior to transport.
10. If optimum properties have not been achieved at this point, contact Baker Hughes INTEQ Technical Services.

Note: *If problems arise, refer to Table 3-13,* ***Troubleshooting the CARBO-DRILL℠ systems****.*

Product Safety and Handling

Utilize normal precautions for employee protection when handling chemical products. Use of appropriate respirator, gloves, goggles, and apron is recommended for employee comfort and protection. Material Safety Data Sheets are available and should be referred to prior to product use. The liquid oil-base fluid products usually contain flammable or combustible liquids and must not be stored around heat, sparks, or open flames. Empty containers should not be reused.

Personal Protective Equipment (PPE)

Eye Wear

Safety goggles are recommended in areas where potentially heavy exposure can occur from misting or splashing of the fluid. These include the areas around the shaker and hopper. Safety glasses fitted with side shields are suitable in other areas.

Protective Clothing

Long sleeve, impermeable coveralls for torso and limb protection are recommended for individuals involved with long term exposure to the fluids. These individuals include mixing plant personnel and rig floor hands. Nitrile or neoprene coated nylon coveralls offer the best combination of protection and durability. The coverall should cover as much exposed skin area as possible. Gloves and foot wear should overlap with the coveralls. Aprons coated with nitrile or neoprene rubber may be used in other areas. All personal protective equipment should be checked frequently for cracks and tears.

Gloves

Impermeable gloves should be worn by all personnel coming into contact with the fluids. Gloves made from neoprene or nitrile rubber are required. Others types will not withstand prolonged exposure to the fluids. Nitrile or neoprene latex blends offer a more flexible glove. Glove surfaces should be textured to provide a more effective gripping area. Gloves should be discarded if the interior surface becomes contaminated with the fluid. Cloth or leather gloves should not be worn at any time.

Footwear

Neoprene or synthetic rubber safety boots or over boots with non-slip soles are recommended. Leather boots that become impregnated with fluid should be discarded.

Barrier Creams

Use barrier creams to cover those areas not covered by personal protective equipment. These areas include the face and neck and portions of the legs and arms where the pieces of PPE overlap.

Note: *See **Formulation Disclaimer** on page 3-2. For **high-temperature** and **deep-water** formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-2 Products Required to Build 100 bbl of CARBO-TEC Oil Fluid 70/30 - 80/20 Oil/Water Ratio

Maximum Temperature °F (°C)	250° (121)	300° (149)	350° (177)
Products:			
CARBO-TEC®, gal	110	130	170
CARBO-MUL® HT, gal	25*	50*	62.5*
CARBO-TROL® HT, 50 lb_m sacks	10	15	20
MIL-LIME™, 50 lb_m sacks	9	11	14

* +1 gal. additional CARBO-MUL HT required per 25 100-lb_m sacks MIL-BAR

Fluid Wt (lb_m/gal)	Diesel (bbl)	Brine† (bbl)	CARBO-GEL™ (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
70/30 Oil/Water Ratio				
8.0	66	30	3	0
8.5	65	30	3	27
9.0	64	29	4	55
9.5	63	29	4	82
10.0	61	28	4	109
10.5	60	27	4	136
11.0	59	27	4	164
11.5	58	26	4	191
12.0	56	26	4	218
12.5	55	25	4	245
80/20 Oil/Water Ratio				
13.0	54	25	4	272
13.5	52	24	4	299
14.0	51	24	4	327
14.5	50	23	4	354
15.0	48	23	4	381
16.0	53	14	4	445

† Based on 25% $CaCl_2$

Note: *See* ***Formulation Disclaimer*** *on page 3-2. For* ***high-temperature*** *and* ***deep-water*** *formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-3 Products Required to Build 100 bbl of CARBO-TEC Oil Fluid 85/15 Oil/Water Ratio

Maximum Temperature °F (°C)	250° (121)	300° (149)	350° (177)
Products:			
CARBO-TEC®, gal	100	115	140
CARBO-MUL® HT, gal	25*	50*	62.5*
CARBO-TROL® HT, 50 lb_m sacks	10	20	20
MIL-LIME™, 50 lb_m sacks	8	9	11
* +1 gal. additional CARBO-MUL HT required per 25 100-lb_m sacks MIL-BAR			

Fluid Wt (lb_m/gal)	Diesel (bbl)	Brine† (bbl)	CARBO-GEL™ (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
85/15 Oil/Water Ratio				
8.0	82	15	7	18
8.5	80	14	7	50
9.0	79	14	7	76
9.5	77	14	7	103
10.0	76	14	7	129
10.5	74	13	7	156
11.0	72	13	7	182
11.5	71	13	7	209
12.0	69	13	7	236
12.5	68	12	7	262
13.0	66	12	7	289
13.5	65	12	7	316
14.0	63	12	7	342
14.5	62	11	7	369
15.0	60	11	7	395
15.5	59	11	6	422
16.0	57	10	6	449
16.5	56	10	6	475
17.0	54	10	6	502
17.5	52	10	6	528
† Based on 25% $CaCl_2$				

Note: *See* ***Formulation Disclaimer*** *on page 3-2. For* ***high-temperature*** *and* ***deep-water*** *formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-4 Products Required to Build 100 bbl of CARBO-TEC Oil Fluid 90/10 - 95/5 Oil/Water Ratio

Maximum Temperature °F (°C)	250° (121)	300° (149)	350° (177)
CARBO-TEC®, gal	85	100	125
CARBO-MUL® HT, gal	25*	50*	62.5*
CARBO-TROL®, 50 lb_m sacks	10	20	20
MIL-LIME™, 50 lb_m sacks	5	6	7
* +1 gal. additional CARBO-MUL HT required per 25 100-lb_m sacks MIL-BAR			

Fluid Wt (lb_m/gal)	Diesel (bbl)	Brine† (bbl)	CARBO-GEL™ (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
90/10 Oil/Water Ratio				
7.6	88	10	9	0
8.0	86	10	9	22
8.5	85	10	9	49
9.0	83	10	9	75
9.5	82	9	9	102
10.0	80	9	9	129
10.5	78	9	9	156
11.0	77	9	9	183
11.5	75	8	9	210
12.0	73	8	9	236
12.5	72	8	9	263
13.0	70	8	9	290
13.5	69	8	9	317
14.0	67	8	9	343
14.5	65	8	9	370
15.0	63	7	9	397
95/5 Oil/Water Ratio				
16.0	62	3	8	471
16.5	61	3	8	499
17.0	59	3	8	526
17.5	57	3	8	553
18.0	56	3	7	579
18.5	54	3	5	606
19.0	52	3	4	633
19.5	50	3	3	660
20.0	49	3	2	687
† Based on 25% $CaCl_2$				

Note: *See **Formulation Disclaimer** on page 3-2. For **high-temperature** and **deep-water** formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-5 Products Required to Build 100 bbl of CARBO-FAST Oil Fluid 70/30 - 80/20 Oil/Water Ratio

Maximum Temperature °F (°C)	200° (93)	250° (121)	300° (149)	350° (177)
CARBO-MUL® HT, gal	40*	50*	60*	70*

* +1 gal additional CARBO-MUL HT required per 25 100-lb_m sacks MIL-BAR

Fluid Wt (lb_m/gal)	Diesel (bbl)	Brine† (bbl)	CARBO-GEL™ (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
70/30 Oil/Water Ratio				
8.0	70	30	7	0
8.5	68	29	7	29
9.0	67	29	7	59
9.5	66	28	7	82
10.0	65	28	7	110
10.5	65	27	7	136
11.0	62	27	7	163
11.5	61	26	7	191
12.0	60	26	7	218
12.5	58	25	7	245
80/20 Oil/Water Ratio				
13.0	57	24	7	272
13.5	56	24	7	299
14.0	55	23	7	327
14.5	53	23	7	353
15.0	52	22	7	380
15.5	58	14	7	408
16.0	56	14	7	436

† 250,000 ppm $CaCl_2$, water.

NOTE: *The volumes and densities are accurate to ± l%. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL^{SM}.*

Note: *See **Formulation Disclaimer** on page 3-2. For **high-temperature** and **deep-water** formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-6 Products Required to Build 100 bbl of CARBO-FAST Oil Fluid 85/15 Oil/Water Ratio

Maximum Temperature °F (°C)	200° (93)	250° (121)	300° (149)	350° (177)
CARBO-MUL® HT, gal	40*	50*	60*	70*

* +1 gal additional CARBO-MUL HT required per 25 100-lb_m sacks MIL-BAR

Fluid Wt (lb_m/gal)	Diesel (bbl)	Brine† (bbl)	CARBO-GEL™ (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
85/15 Oil/Water Ratio				
8.0	84	15	8	18
8.5	82	14	8	50
9.0	81	14	8	76
9.5	79	14	8	103
10.0	76	13	8	129
10.5	74	13	8	156
11.0	73	13	8	182
11.5	71	13	8	209
12.0	70	12	8	236
12.5	70	12	8	262
13.0	68	12	8	289
13.5	67	12	8	316
14.0	65	12	7	342
14.5	64	11	7	369
15.0	62	11	7	395
15.5	61	11	7	422
16.0	59	10	7	449
16.5	58	10	7	475
17.0	56	10	7	502
17.5	54	10	7	528
18.0	53	9	6	555

†. 250,000 ppm $CaCl_2$ water

NOTE: *The volumes and densities are accurate to ± l%. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL^{SM}.*

Note: *See **Formulation Disclaimer** on page 3-2. For **high-temperature** and **deep-water** formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-7 Products Required to Build 100 bbl of CARBO-FAST Oil Fluid 90/10 Oil/Water Ratio

Maximum Temperature °F (°C)	200° (93)	250° (121)	300° (149)	350° (177)
CARBO-MUL® HT, gal	40*	50*	60*	70*

* +1 gal additional CARBO-MUL HT required per 25 100-lb_m sacks MIL-BAR

Fluid Wt (lb_m/gal)	Diesel (bbl)	Brine† (bbl)	CARBO-GEL™ (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
90/10 Oil/Water Ratio				
8.0	88	9.7	9	36
8.5	86	9.6	9	62
9.0	84	9.4	9	89
9.5	83	9.2	9	115
10.0	81	9.0	9	142
10.5	80	8.9	9	169
11.0	78	8.6	9	195
11.5	76	8.5	9	222
12.0	75	8.3	9	247
12.5	73	8.1	8	275
13.0	72	7.9	8	301
13.5	70	7.8	8	328
14.0	68	7.6	8	354
14.5	67	7.4	8	380
15.0	65	7.2	7	408
15.5	63	7.0	7	434
16.0	62	6.8	7	460
16.5	60	6.7	7	486
17.0	59	6.5	6	513
17.5	57	6.3	6	541
18.0	55	6.1	6	566
18.5	54	6.0	6	593
19.0	52	5.8	6	620

† 250,000 ppm $CaCl_2$ water

NOTE: *The volumes and densities are accurate to ± 1%. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL.*

Note: *See **Formulation Disclaimer** on page 3-2.*

Table 3-8 Material Required to Build 100 bbl of CARBO-CORE Oil Fluid

Fluid Wt (lb_m/gal)	Oil (bbl)	CARBO-GEL (50 lb_m sacks)	OMNI-PLEX (gallons)	MIL-LIME (50 lb_m sacks)	CARBO-TEC (gallons)	CARBO-TROL HT (50 lb_m sacks)	MIL-BAR (100 lb_m sacks)
7.2	98	25	75	2	24	24	
7.5	97	25	75	2	24	23	12
8.0	95	25	75	2	24	22	39
8.5	93	25	75	2	24	22	66
9.0	92	25	75	2	24	22	93
9.5	90	24	75	2	24	22	120
10.0	88	22	75	2	24	21	147
10.5	86	21	75	2	24	21	174
11.0	85	19	75	2	24	20	201
11.5	83	18	75	2	24	20	227
12.0	81	16	50	2	24	19	254
12.5	79	15	50	2	24	19	281
13.0	78	14	50	2	24	19	308
13.5	76	13	50	2	24	18	335
14.0	74	12	50	2	24	18	361
14.5	72	11	25	2	24	17	388
15.0	71	9	25	2	24	17	415
15.5	69	9	25	2	24	17	441
16.0	67	8	25	2	24	16	468
16.5	65	7	25	2	24	16	495

Note: *See* ***Formulation Disclaimer*** *on page 3-2. For* ***high-temperature*** *and* ***deep-water*** *formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-9 Products Required to Build 100 bbl of SYN-TEQ Fluid 70/30 - 80/20 Synthetic/Water Ratio

Maximum Temperature °F (°C)	250° (121)	300° (149)
Products:		
OMNI-MUL™, gal	110*	100*
MIL-LIME™, 50 lb_m sacks	4	4
* +1 gal additional OMNI-MUL required per 25 100-lb_m sacks MIL-BAR		

Fluid Wt (lb_m/gal)	ISO-TEQ™ (bbl)	Brine† (bbl)	CARBO-GEL® (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
70/30 SWR				
8.0	66	30	4	0
8.5	65	30	4	27
9.0	64	29	5	55
9.5	63	29	5	82
10.0	61	28	5	109
10.5	60	27	5	136
11.0	59	27	5	164
11.5	58	26	5	191
12.0	56	26	5	218
12.5	55	25	5	245
80/20 SWR				
13.0	54	25	5	272
13.5	52	24	5	299
14.0	51	24	5	327
14.5	50	23	5	354
15.0	48	23	5	381
16.0	53	14	5	445
† 250,000 ppm $CaCl_2$ water				

Note: *See* ***Formulation Disclaimer*** *on page 3-2. For* ***high-temperature*** *and* ***deep-water*** *formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-10 Products Required to Build 100 bbl of SYN-TEQ Fluid 85/15 Synthetic/Water Ratio

Maximum Temperature °F (°C)	250° (121)	300° (149)
Products:		
OMNI-MUL™, gal	110*	110*
MIL-LIME™, 50 lb_m sacks	4	4
* +1 gal additional OMNI-MUL required per 25 100-lb_m sacks MIL-BAR		

Fluid Wt (lb_m/gal)	ISO-TEQ™ (bbl)	Brine† (bbl)	CARBO-GEL® (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
85/15 SWR				
8.0	82	15	9	18
8.5	80	14	9	50
9.0	79	14	9	76
9.5	77	14	9	103
10.0	76	14	9	129
10.5	74	13	9	156
11.0	72	13	9	182
11.5	71	13	9	209
12.0	69	13	9	236
12.5	68	12	8	262
13.0	66	12	8	289
13.5	65	12	8	316
14.0	63	12	8	342
14.5	62	11	8	369
15.0	60	11	7	395
15.5	59	11	7	422
16.0	57	10	7	449
16.5	56	10	7	475
17.0	54	10	7	502
17.5	52	10	7	528
18.0	51	9	5	555
† 250,000 ppm $CaCl_2$, water.				

Note: *See* ***Formulation Disclaimer*** *on page 3-2. For* ***high-temperature*** *and* ***deep-water*** *formulations, contact Baker Hughes INTEQ Technical Services.*

Table 3-11 Products Required to Build 100 bbl of SYN-TEQ Fluid 90/10 - 95/5 Synthetic/Water Ratio

Maximum Temperature °F (°C)	250° (121)	300° (149)
Products:		
OMNI-MUL™, gal	110*	110*
MIL-LIME™, 50 lb_m sacks	4	4
* +1 gal additional OMNI-MUL required per 25 100-lb_m sacks MIL-BAR		

Fluid Wt (lb_m/gal)	ISO-TEQ™ (bbl)	Brine† (bbl)	CARBO-GEL® (50 lb_m sacks)	MIL-BAR® (100 lb_m sacks)
		90/10 SWR		
7.6	88	10	10	0
8.0	86	10	10	22
8.5	85	10	10	49
9.0	83	10	10	75
9.5	82	9	10	102
10.0	80	9	10	129
10.5	78	9	10	156
11.0	77	9	10	183
11.5	75	8	10	210
12.0	73	8	10	236
12.5	72	8	10	263
13.0	70	8	10	290
13.5	69	8	10	317
14.0	67	8	10	343
14.5	65	8	10	370
15.0	63	7	10	397
		95/5 SWR		
16.0	62	3	8	471
16.5	61	3	8	499
17.0	59	3	8	526
17.5	57	3	8	553
18.0	56	3	7	579
18.5	54	3	5	606
19.0	52	3	4	633
† 250,000 ppm $CaCl_2$ water				

Note: *See* ***Formulation Disclaimer*** *on page 3-2.*

Table 3-12 Material Required to Build 100 bbl of SYN-CORE^{SM} Fluid

Fluid Wt (lb_m/gal)	ISO-TEQ (bbl)	CARBO-GEL (50 lb_m sacks)	OMNI-PLEX (gallons)	MIL-LIME (50 lb_m sacks)	OMNI-TEC (gallons)	CARBO-TROL HT (50 lb_m sacks)	MIL-BAR (100 lb_m sacks)
7.2	98	25	120	2	24	24	
7.5	97	25	110	2	24	23	12
8.0	95	25	105	2	24	22	39
8.5	93	25	100	2	24	22	66
9.0	92	25	90	2	24	22	93
9.5	90	24	90	2	24	22	120
10.0	88	22	80	2	24	21	147
10.5	86	21	75	2	24	21	174
11.0	85	19	70	2	24	20	201
11.5	83	18	60	2	24	20	227
12.0	81	16	55	2	24	19	254
12.5	79	15	55	2	24	19	281
13.0	78	14	50	2	24	19	308
13.5	76	13	50	2	24	18	335
14.0	74	12	45	2	24	18	361
14.5	72	11	40	2	24	17	388
15.0	71	9	35	2	24	17	415
15.5	69	9	30	2	24	17	441
16.0	67	8	25	2	24	16	468
16.5	65	7	20	2	24	16	495

Special Rig Equipment and Precautions

1. A fluid-saver box with a hose connected to the flow line should be installed to save fluid lost from connections and trip.
2. Pipe wipers will help keep the outside of the drillpipe clean during trips.
3. Use high-speed, linear motion shakers capable of processing 110% of the fluid volume at the smallest screen size anticipated.
4. If lost circulation is a possibility, a frac tank for base fluid storage on location is recommended.
5. The pits should be covered to prevent rain water contamination.
6. All water valves around the pits should be disconnected to prevent water contamination.
7. Shaker screens and fluid cleaner screens should be cleaned with a bucket of oil/ISO-TEQ™ and an air gun.
8. Do not use plastic or phenolic-resin-type materials for lost circulation.
9. Steam cleaners may be needed for general rig clean up. MIL-CLEAN® diluted in water is an excellent cleaner.
10. Have absorbents available to contain and “dry up” spills and splashes, particularly on the rig floor.
11. Fluid vacuum systems around to rig to recover spilled fluid.

Displacement Procedures

Displacement can occur either in casing or open hole. Cased hole displacements are preferred. Prior to displacement, the engineer should make certain all pits and lines are as clean as possible. The trap doors on the pits can be packed with barite to help prevent leaking.

The water-base fluid to be displaced should be diluted to reduce yield point and gel strengths. This will help prevent contamination of the CARBO-DRILL/SYN-TEQ^{SM} fluid.

A water spacer of sufficient volume to occupy 500 to 1000 feet of annular space should be used to chase the water-base fluid up the hole. This will thin the water-base fluid and thicken the oil fluid to help hole cleaning and removal of the water-base filter cake.

An oil/ISO-TEQ™ spacer of the same size is used when displacing an oil/SYN-TEQ^{SM} fluid with a water-base fluid.

During displacement, the drill pipe should be rotated and reciprocated. Use a high pump rate to help prevent channeling. Once displacement commences, the pumps *should not* be shutdown.

The total strokes should be calculated for the spacer to come around to the shaker. This will help locate the interface. Bypass the shakers and remove the water-base fluid to a reserve or waste pit. Any contaminated oil-base fluid found at the interface should also be discarded.

Treatment

See Table 3-13 plus other sections as designated.

Table 3-13 Troubleshooting the CARBO-DRILL [SYN-TEQ] Systems Guide for Pilot Testing

Problem	Indications	Cause	Treatment
Problem mixing fluid at mixing plant	Poor emulsions stability. Barite settling. Dull grainy appearance to fluid. Fluid very thin with no yield or gel strength.	1. Inadequate shear. 2. Very cold. 3. Poor wetting of barite. 4. High electrolyte content. Normally greater than 350,000 ppm. 5. Surfactant contamination possible if $CaCl_2$ brine has been used as completion or workover fluid.	1. Maximize shear. 2. Lengthen mixing time. 3. Slow additions of barite. Add CARBO-MUL. If severe, add small amount of OMNI-COTE. 4. Dilute back with fresh H_2O. Once emulsion is formed, can add more $CaCl_2$ to obtain desired activity. 5. Pilot test with known $CaCl_2$ brine to determine if problem does exist. 6. Patience.
Lost circulation	Pit volume decreases. Loss of returns.	1. Hydrostatic pressure is greater than formation pressure.	1. Add bridging agents [i.e., MIL-CARB, CHEK-LOSS, SOLUFLAKE], nut plug. Never add phenolic resin materials. If possible, reduce fluid weight.

Troubleshooting the CARBO-DRILL [SYN-TEQ] Systems Guide for Pilot Testing (continued)

Problem	Indications	Cause	Treatment
High viscosity	High PV, high YP. Increasing funnel viscosity. Increasing retort solids. Increase in water content.	1. High solids content. 2. Water contamination. 3. Improper OWR/SWR. 4. Excessive clay.	1. Dilute with base fluid. Maximize solids control equipment. Add emulsifiers. 2. Add emulsifiers. If severe, add OMNI-COTE. 3. Dilute with base fluid.
Sloughing shale	Fill on connections and trip. Torque and drag. Increase of cuttings across shaker.	1. Drilling under-balanced. 2. Excessive filtrate. 3. Tectonic stresses. 4. A_w too low.	1. Increase fluid weight. 2. Add emulsifiers. Add CARBO-TROL A-9 and/or CARBO-TROL HT. 3. Add asphaltics/gilsonites. 4. Adjust salt content of internal phase to match formation activity.
High filtration	High HT/HP filtrate with increasing free H_2O. Low ES. Fill on connections and trips. Sloughing shale.	1. Low emulsifier content. 2. Low concentration of fluid loss control additives. 3. High bottomhole temperature.	1. Add CARBO-MUL HT [OMNI-MUL]. Add CARBO-TEC [OMNI-TEC] and lime if a CARBO-TEC [SYN-TEQ] system. 2. Add CARBO-TROL HT. 3. Add more CARBO-MUL HT [OMNI-MUL]. Add CARBO-TEC [OMNI-TEC] and lime. Convert to CARBO-TEC system. Add more CARBO-TROL A-9 and CARBO-TROL HT.

Troubleshooting the CARBO-DRILL [SYN-TEQ] Systems Guide for Pilot Testing (continued)

Problem	Indications	Cause	Treatment
Low emulsion stability	Dull, grainy appearance to fluid. High HT/HP fluid loss. Free H_2O in HT/HP filtrate. Barite settling out. Blinding of shaker screens. Extreme cases can cause water wetting of solids.	1. Low emulsifier. 2. Super-saturated with $CaCl_2$. 3. Water flows 4. Mixing fluid at mixing plant.	1. Add CARBO-MUL HT [OMNI-MUL]. Add CARBO-TEC [OMNI-TEC] and lime if CARBO-DRILL [SYN-TEQ] system. 2. Dilute back with fresh H_2O and add CARBO-MUL HT [OMNI-MUL]. 3. Add CARBO-MUL HT [OMNI-MUL]. Can also add CARBO-TEC [OMNI-TEC]and lime if CARBO-TEC [SYN-TEC] system. 4. Maximize shear. Check electrolyte content (the higher the content, the harder the emulsion is to form).
Water wetting of solids	Agglomeration of barite on sand-content test. Sticky cuttings. Blinding of shaker screens. Settling of barite. Dull, grimy appearance of fluid. Low ES. Free H_2O in HT/HP filtrate.	1. Inadequate emulsifiers. 2. Water-base fluid contamination. 3. Super-saturated $CaCl_2$	1. Add CARBO-MUL HT [OMNI-MUL]. 2. Add CARBO-MUL HT [OMNI- MUL]. 3. Dilute with fresh H_2O and add CARBO-MUL HT [OMNI-MUL].
Barite settling	Settling of barite in heating cup. Ultra low shear rate rheology. Varying fluid densities.	1. Poor oil wetting of barite. 2. Inadequate suspension.	1. Add emulsifiers and/or wetting agents. Slow addition of barite. 2. Add CARBO-GEL or OMNI-PLEX.

Changing Oil/Synthetic-to-Brine Ratio

It may be necessary, at some time, to change the oil/synthetic to brine ratio of the CARBO-DRILL^{SM}/SYN-TEQ^{SM} system. The simplest calculation to make is increasing the oil/synthetic brine ratio, since only oil/synthetic is added.

To increase the oil/synthetic brine ratio with additions of oil/synthetic, complete the following calculation,

$$F_O = \frac{R_O\left(\frac{V_O + V_B}{100}\right) - V_O}{R_B} \times Vol_{sys} \tag{3-1}$$

where

F_O = volume of oil/synthetic (bbl),

R_O = required oil or synthetic ratio,

R_B = required brine ratio,

Vol_{sys} = system volume.

To decrease the oil/synthetic brine ratio with additions of brine, complete the following calculation,

$$F_B = \frac{R_B\left(\frac{V_O + V_B}{100}\right) - V_B}{R_O} \times Vol_{sys} \tag{3-2}$$

where

F_B = Volume of brine (bbl).

Additions of freshwater will increase the controlled activity of the system. If brine is not available, $CaCl_2$ salt should be added to the drilling fluid when decreasing the oil/water ratio with freshwater.[1] The quantity of calcium chloride necessary to maintain a constant activity when adding freshwater is calculated as follows.

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[1] Use the respective Salt Tables in Chapter 5, if sodium chloride or magnesium chloride is used.

$$F_W = \frac{H_2O\text{, gal/bbl} \times F_B}{42} \tag{3-3}$$

$$CaCl_{2_{add}} = CaCl_2\text{, }lb_m\text{/bbl} \times F_B \tag{3-3a}$$

where

F_W = volume of water (bbl),

H_2O, gal/bbl = H_2O gal/bbl for given wt %,

$CaCl_2$ (see Calcium Chloride table in Chapter 5),

$CaCl_{2_{add}}$ = additions of $CaCl_2$ to system volume,

$CaCl_2$, lb_m/bbl = $CaCl_2$ concentration of wt % from the calcium chloride table in the Engineering Data chapter, Section 4.

Barite Plugs For Oil/Synthetic-Base Fluids

Materials and Procedure

Occasionally when drilling an oil/synthetic-base fluid, it may become necessary to set a barite plug because of excessive formation pressures. Water-base barite plugs *should not* be used where oil/synthetic-base fluid is in use. The following formulation and procedure is used to prepare one barrel of 18.0 lb_m/gal (oil/synthetic-base) barite plug.

Materials

1. Base fluid	24.6 gal
2. CARBO/OMNI-MUL™	0.5 gal
3. OMNI-COTE™	0.5 gal
4. MIL-BAR®	576 lb_m

Procedure

1. Clear all lines that will be used to pump the plug of water or water-wet materials. (This may require flushing the lines with diesel oil.)

2. To the appropriate amount of base fluid, add the required CARBO-MUL®/OMNI-MUL™ and OMNI-COTE™ simultaneously and mix for 10 minutes.
3. Mix the required MIL-BAR® with the fluid mixture and displace continuously into the hole with the pumping unit.

Note: *Spot the barite plug in the same manner as a water base plug (see* ***Pressure Control*** *in Chapter 4).*

H_2S or CO_2 Gases

CAUTION: *Extreme care should be taken to avoid inhalation of* ***any*** *H_2S gas. (See Table 4-7)*

Due to the innate ability of oil-base fluids to prevent corrosion, there is no need to use corrosion products with the CARBO-DRILL℠ or SYN-TEQ℠ families of fluids. Lime hydrate (1 to 3 lb_m/ bbl or other excess amount) should be added to the fluid and maintained (as per the lime titration) when drilling in areas where acid gases are likely to be encountered. This will prevent any adverse affects on the emulsion stability should H_2S or CO_2 be incorporated in the fluid.

Note: *Do not use CARBO-TROL A-9 or OMNI-TROL™ in these environments as they may strip lime out of the system causing emulsion instability. MIL-GARD® is recommended as an acid gas scavenger.*

Lost Circulation or Seepage Losses

1. Seepage loss is a common problem in slightly-porous or permeable formations due to low-colloid content of fluid. Remedial procedures include the following.
    - Reduce HT/HP fluid loss with additions of CARBO-TROL®
    - Utilize CHEK-LOSS®, W.O.™ 30, or SOLUFLAKE® with additions of 5 to 8 lb_m/bbl to active system

- Utilize “slugging technique”, in which a combination of CHEK-LOSS® and W.O. 30 are mixed at 30 to 40 lb_m/bbl in a 20 to 50 bbl pill and passed through the annulus. Pill can be retrieved and isolated for further use. This avoids a build-up of fine solids in the system.

2. Partial losses (highly-porous or fractured formations) can be combated with additions of LCM to active system. Caution should be exercised to avoid water wetting of LCM material. Remedial procedures include the following.

   - Spot pill using various sizes of LCM (CHEK-LOSS, W.O. 30, MIL-PLUG®, etc.) with a concentration of 30 to 40 lb_m/bbl.
   - Go immediately to a high-filtration-type of squeeze such as DIASEAL® M (see Table 2-35). Additions of 10 to 15 lb_m/bbl W.O.™ 30 in a DIASEAL M squeeze can improve squeeze success.
   - Utilize a high-filtration diesel oil- or synthetic oil-bentonite squeeze as outlined below.

High-Filtration Squeeze for Oil Fluids Formulation
(1 bbl of 18 lb_m/gal Slurry)

MILGEL®	300 - 400 lb_m
Base Fluid	0.6 bbl
CARBO-GEL®	3 lb_m
CARBO-TEC®	1 lb_m
CHEK-LOSS®	10 - 15 lb_m
Barite	540 lb_m

(Follow *Squeeze Procedure* as outlined in Table 2-36.)

3. Total losses (caverns, vugs, or induced fractures) can be combated with the use of high-filtration squeezes as outlined above to avoid pumping costly fluid away.

   Remedial procedures include the following.

   - Cement squeezes into loss zone

   - Change out system to less costly water-base fluid until circulation is established and drilling can proceed or casing can be run

Oil-base fluids will not solvate or swell clays. While this characteristic is desirable for wellbore inhibition, it causes difficulty when trying to control lost circulation or seepage losses. Lost circulation materials (LCM) which absorb water must be used with caution since the oil/brine ratio could be adversely affected. All other types of LCM, which plug formation pore space, will assist in reducing fluid losses. The specially designed particle size distribution of CHEK-LOSS® is an excellent product for seepage-control losses. DIASEAL® M can also be used with oil-base fluids to bridge over severe loss zones.

Measuring Oil on Cuttings

Description

This procedure is specifically intended to measure oil from cuttings generated during a drilling operation. It is a retort test which measures all oil and water released from a cuttings sample when heated in a calibrated and properly operating “retort” instrument.

In this retort test, a known weight of cuttings is heated in the retort chamber to vaporize the liquids associated with the sample. The oil and water vapors are then condensed, collected, and measured in a precision graduated receiver.

Obtaining a representative sample requires special attention to the details of sample handling (location, method, frequency). The sampling procedure in a given area may be specified by local or governmental rules.

Equipment

1. Retort instrument – The recommended retort instrument has a 50 cm^3 volume with an external heating jacket.

   Retort Specifications

   - Retort assembly – retort body, cup, and lid
   - Material: 303 stainless steel or equivalent

- Volume: Retort cup with lid
- Cup volume: 50 cm^3
- Precision: ± 0.25 cm^3
- Condenser – capable of cooling the oil and water vapors below their liquification temperature
- Heating jacket – nominal 350 watts
- Temperature control – capable of limiting temperature of retort to 930° ± 70°F (500 ± 38°C)

2. Liquid receiver with base (10 cm^3 and 20 cm^3) — specially designed cylindrical glassware (Pyrex® or equivalent glass*) with a rounded bottom to facilitate cleaning and a funnel-shaped top to catch falling drops. See Table 3-14.

**Pyrex is a registered trademark of Corning Glass Works.*

Table 3-14 Receiver Specifications

Total volume	10 cm^3	20 cm^3	50 cm^3
Precision (0 to 100%)	± 0.05 cm^3	± 0.05 cm^3	± 0.05 cm^3 nominal
Outside diameter	10 mm	13 mm	
Wall thickness	1.5 ± 0.1 mm	1.2 ± 0.1 mm	
Frequency of graduation marks (0 to 100%)	0.10 cm^3	0.10 cm^3	1.0 cm^3
Calibration	To contain (TC) @ 20°C		
Scale	cm^3	cm^3	cm^3

Note: **Verification of receiver volume.** *The receiver volume should be verified gravimetrically. The procedure and calculations are in Chapter 1,* ***Drilling Fluid Testing Procedures****.*

3. Top-loading balance – capable of weighing 2000 g and precision of 0.1 g
4. Fine steel wool (No. 000) – for packing retort body
5. Thread sealant/lubricant – Never-Seez® or equivalent high-temperature lubricant**
6. Pipe cleaners – to clean condenser and retort stem
7. Brush – to clean receivers
8. Retort spatula – to clean retort cup
9. Corkscrew – to remove spent steel wool

*** Never-Seez is a registered trademark of the Never-Seez Compound Corp.*

Procedure

1. Clean and dry the retort assembly and condenser.
2. Pack retort body with steel wool.
3. Apply lubricant/sealant to threads of retort cup and retort stem.
4. Weigh and record the total mass of the retort cup, lid, and retort body with steel wool. This is mass (A), grams.
5. Collect a representative cuttings sample.
6. Partially fill the retort cup with cuttings and place the lid on the cup.
7. Screw the retort cup with lid onto the retort body. Weigh and record the total mass. This is mass (B), grams.
8. Attach the condenser. Place the retort assembly into the heating jacket.
9. Weigh and record the mass of a clean, dry, liquid receiver. This is mass (C), grams. Place the receiver below condenser outlet.
10. Plug in the retort. Allow to run a minimum of one hour.

Note: *If solids boil over into receiver, the test must be rerun. Pack the retort body with a greater amount of steel wool (Step 2) and repeat the test.*

11. Remove the liquid receiver and allow to cool. Record the volume of water recovered. This is (V), cm^3.

Note: *If an emulsion interface is present between the oil and water phases, heating the interface may break the emulsion. As a suggestion, remove the retort assembly from the heating jacket by grasping the condenser. Carefully heat the receiver along the emulsion band by gently touching the receiver with the hot retort assembly. Avoid boiling the liquids. After the emulsion interface is broken, allow the liquid receiver to cool. Read the water volume at the lowest point of the meniscus.*

12. Weigh and record the mass of the receiver and its liquid contents (oil plus water). This is mass (D), grams.
13. Unplug retort. Remove the retort assembly and condenser from the heating jacket and allow to cool. Remove the condenser.
14. Weigh and record the mass of the cooled retort assembly without the condenser. This is mass (E), grams.
15. Clean retort assembly and condenser.

Calculations

1. Calculate the Mass of Oil from the Cuttings
   - Mass of the *wet cuttings* sample (M_w) equals the mass of the retort assembly with cuttings (B) minus the mass of the empty retort assembly (A)

     $$M_w = B - A$$

   - Mass of the *dry retorted cuttings* (M_d) equals the mass of the cooled retort assembly (E) minus the mass of the empty retort assembly (A)

     $$M_d = E - A$$

   - Mass of the *oil* (M_o) equals mass of the liquid receiver with its contents (D) minus the sum of the mass of dry receiver (C) and mass of the water (V)

     $$M_o = D - (C + V)$$

Note: *Assuming the density of water is one g/cm^3, the volume of water is equivalent to the mass of the water.*

2. Mass Balance Requirement
   - The sum of M_d, M_o, and V should be within 5% of the mass of the wet sample.

$$\frac{M_d + M_o + V}{M_w} = 0.95 \text{ to } 1.05$$

The calculation should be repeated if this requirement is not met.

3. Report Oil from Cuttings
   - Mass of oil (g) per kg of wet cuttings sample equals

     $$\frac{M_o}{M_w} \times 1000$$

   - Mass of oil (g) per kg of dry retorted cuttings equals

     $$\frac{M_o}{M_d} \times 1000$$

Note: *When expressing oil from cuttings in terms of the dry (retorted) cuttings, the oil content may be higher than that calculated from the wet cuttings sample due to interstitial water extracted during retorting.*

— Notes —

Chapter 4

Engineering

Hydraulics

Introduction

In connection with drilling fluids, the term hydraulics refers to the operation where the drilling fluid is used to transfer pressure from the surface to the bit where the pressure drop across the bit is used to enhance rate of penetration. Part of the fluid's energy is also expended in sweeping the area ahead of the bit free of generated cuttings and preventing the agglomeration of cuttings on the bit face and body.

For the fluid to perform some of its other functions (e.g., carrying cuttings to the surface), the fluid pump must be capable of overcoming the accumulated pressure losses associated with the surface equipment, the drillstring, the bit, and the annulus. The pump must also be capable of delivering a flow rate, at that pressure, sufficient to transport the cuttings up and out of the wellbore. These pressure losses also affect the total pressure exerted by the fluid column on the wellbore, potentially raising loss of circulation, kick control, and other wellbore stability issues.

The purpose of this section is to give the engineer the basic equations and procedures used to perform an analysis of the hydraulic capabilities of the circulating system. Because the rheology of the drilling fluid directly affects the circulating system pressure losses, the more accurately the rheological models used to describe the drilling fluid represent the fluid, the more precise the hydraulic analysis can be. The following section is a brief description of the common rheological models used to describe drilling fluids.

Rheological Models

Newtonian

A rheological model is a description of the relationship between the shear stress (τ) experienced by the fluid and the shear rate (γ). For a Newtonian fluid, the ratio of shear stress to shear rate is a constant. This constant is the viscosity (μ) of the fluid. Thus the equation describing the rheology of a Newtonian fluid can be written as $\mu = \tau/\gamma$,

where

μ = viscosity, poise (dyne – sec/cm^2),

τ = shear stress (force/area) (dynes/ cm^2),

γ = shear rate (secs^{-1}).

The equation is called Newton's law of viscosity. All gases at ambient temperature and pressure and most simple fluids (like water) exhibit Newtonian behavior.

Fluids that do not follow Newton's law of viscosity are termed non-Newtonian. The flow behavior of non-Newtonian fluids is much more complex than Newtonian fluids. For these fluids, the viscosity varies with the shear rate. Most drilling fluids are non-Newtonian and vary considerably in their flow behavior. To be meaningful, a viscosity measurement made on a non-Newtonian fluid must always specify the shear rate. The term effective viscosity (μ_e) is used to differentiate viscosity measurements made on non-Newtonian fluids from Newtonian fluids. Effective viscosity is always measured or calculated at the shear rate corresponding to the existing flow conditions in the wellbore or drill pipe.

Drilling fluids are shear thinning when they have less viscosity at higher shear rates than at lower shear rates. One type of shear thinning fluid will begin to flow as a soon as any shearing force or pressure is applied to it. Increasing shear rate causes a progressive decrease in viscosity. Such a fluid is termed pseudoplastic.

Another type of pseudoplastic fluid will not begin to flow until a threshold shear stress is applied. The threshold stress is called the yield stress.

Bingham Plastic

Because of its simplicity, the model most commonly used to describe the rheological properties of drilling fluids is the Bingham Plastic model. The model assumes that the shear stress is a linear function of shear rate once a specific shear stress has been exceeded (the threshold shear stress or yield point) and is expressed as $\tau = YP + PV (\gamma)$, where

YP = yield point, lb$_f$ /100 ft^2,

PV = plastic viscosity, cp (centipoise, $^1/_{100}$ Poise).

Because this model was developed from data determined between the shear rates of 500 to 1000 sec^{-1}, it best characterizes a fluid at higher shear rates. The PV and YP are calculated from conventional concentric viscometer data taken at 600 and 300 rpm with the following equations.

1. $PV = \theta_{600} - \theta_{300}$, where
   - PV = plastic viscosity, cp
   - θ_{600} = 600 rpm dial reading
   - θ_{300} = 300 rpm dial reading
2. $YP = \theta_{300} - PV$

The shear rate in rpm multiplied by 1.702 gives the shear rate in sec^{-1} for conventional oilfield rheometers. Once the PV and YP values have been determined, the model can be used to determine the shear stress at any given shear rate.

Power Law

The Power Law model describes a fluid in which shear stress versus shear rate is a straight line when plotted on log-log graph paper. Because it more closely approximates the behavior of a drilling fluid at low shear rates than the Bingham Plastic model, it is often used to monitor the suspension characteristics and calculate the pressure loss of the drilling fluid in the annulus. The power law model is

$\tau = K\gamma^n$, where

K = the fluid consistency index (lb-sec^n/100 ft^2),

n = the power law exponent (dimensionless).

The rheological parameters n and K can be calculated from any two shear-rate/shear-stress data points. Since it is rare that a log-log plot of all rheological data will be a straight line, it is better to determine n and K at the shear rates inside the drillstring (n_p and K_p) and inside the annulus (n_a and K_a). Better accuracy will result from the use of n and K in the 5 to 200 sec^{-1} shear rate range for the annulus and in the 200 to 1000 sec^{-1} shear rate range for the inside pipe.
(rpm reading = sec^{-1} ÷ 1.7).

The viscometer dial readings from a standard six-speed instrument can be used to determine the power law constants. Normal practice is to use the 3-rpm and 100-rpm readings for the *low* shear rate and the 300-rpm and 600-rpm readings for the *high* shear rate range. The general formulas for n and K are

$$n = \frac{\log(\tau_2 / \tau_1)}{\log(\gamma_2 / \gamma_1)}$$

$$K = \frac{\tau_2}{(\gamma_2)^n}$$

where

τ_2 = the shear stress reading at the higher shear rate,

τ_1 = the shear stress reading at the lower shear rate,

γ_2 = the higher shear rate (rpm),

γ_1 = the lower shear rate (rpm).

If the 600 and 300 rpm rheometer dial readings are used, these equations simplify to

$$n = 3.32 \log\left[\frac{\theta_{600}}{\theta_{300}}\right]$$

$$K = \frac{300}{511^n}$$

Herschel - Buckley (Modified Power Law)

This model combines the features of the Newtonian, Bingham Plastic, and Power Law models. It is a three parameter model that reproduces the results of the previous three models when the appropriate parameters have been measured. Unfortunately, the three parameters are difficult to derive from the rheometer readings. In practice, it is assumed that the YP is equal to the 3 rpm reading.

Using this assumption allows the calculation of the n and K values. The general form of the equation is $\tau = YP + K\gamma^n$,

where

YP = θ_3 (lb/100 ft^2),

n = (3.32) log [(θ_{600} – YP) ÷ (θ_{300} – YP)],

K = θ_{300} ÷ 511^n.

Casson Model

The Casson model frequently fits the behavior of solids laden drilling fluids in the low shear rate region better than either the Bingham Plastic or Power Law models. However, use of the Casson model for pressure loss calculations is a difficult and complicated process and is rarely attempted. It is a two parameter model written as

$\tau^{1/2} = (t_y^{1/2}) + (\mu_\infty^{1/2})(\gamma^{1/2})$,

where a linear coordinate plot of $\tau^{1/2}$ and $\gamma^{1/2}$ gives $\tau_y^{1/2}$ as the intercept and $\mu_\infty^{1/2}$ as the slope of the straight line.

Robertson-Stiff

The Newtonian, Bingham Plastic, and Power Law models are specific cases of the Robertson-Stiff model. It is a three parameter model that includes the 3 rpm rheometer dial reading and is written in its general form as $\tau = K(\gamma_0 + \gamma)^n$.

To use common rheometer data for the analysis of a fluid conforming to the Robertson-Stiff model, the general equation becomes

$$\left(\frac{\tau_1}{\tau_2}\right)^{\frac{1}{n}}\left(\frac{N_3 - N_2}{N_3 - N_1}\right) + \left(\frac{\tau_3}{\tau_2}\right)^{\frac{1}{n}}\left(\frac{N_2 - N_1}{N_3 - N_1}\right) = 1$$

where

N_3, N_2, and N_1 are rpm speeds and $N_3 > N_2 > N_1$,

τ_3, τ_2, and τ_1 are rheometer sheer stress readings at N_3, N_2, and N_1, respectively.

This equation must be solved iteratively to find n. γ_0 and k can then be calculated by solving the following equations.

$$\gamma_0 = \frac{\pi\left((N_3)(\tau_2)^{\frac{1}{n}} - (N_2)(\tau_3)^{\frac{1}{n}}\right)}{30\ \ln b\left((\tau_3)^{\frac{1}{n}} - (\tau_2)^{\frac{1}{2}}\right)}$$

$$k = \tau_2\left[\frac{n\left(1 - b^{\frac{-2}{n}}\right)}{\overset{n_2}{\frac{\pi}{15}} + 2\gamma_0(\ln b)}\right]$$

where

b = the ratio of the rheometer sleeve radius to the bob radius.

The Robertson-Stiff equation will generally provide the best approximation for pressure losses in the circulating system in most drilling situations. It will not, however, emulate a fluid that follows the Casson equation.

INTEQ Hydraulics Analysis

The programs PRESMOD, DEAP and EC*TRAK have the option of using either Robertson-Stiff, Herschel-Bulkley, or Casson models. These programs are used any time detailed hydraulic calculations are required. The usual hydraulics analysis makes use of the Power Law model.

The objective of a hydraulics analysis is to assess the effects of the viscosity of the drilling fluid on certain critical drilling parameters. The following parameters are evaluated in the analysis.

Parameters

1. Determining annular pressure losses to establish *equivalent circulating density* (ECD). ECD is important for prevention of loss of circulation and preserving casing shoe integrity.
2. Assessing the effects of fluid changes on the system's hydraulic performance.
3. Optimizing hydraulics for enhanced drilling performance (e.g., increased ROP).
4. Ensuring good hole cleaning (cuttings transport and concentration in the annulus).
5. Preventing borehole erosion from turbulent flow in the annulus.
6. Preventing borehole instability and pressure control problems from pulling pipe too fast (swabbing).
7. Preventing loss of circulation from running pipe too fast (surging).

Process

The analysis consists of eight basic steps.

1. Draw the wellbore geometry.
2. Calculate the total annular pressure drop using the drilling fluid properties, flow rate, and well geometry.
3. Establish the equivalent circulating density (ECD) from the annular pressure drop.
4. Establish the critical flow velocity and flow rate around the drill collars.
5. Establish swab and surge pressures.
6. Calculate cuttings transport efficiency and concentration in the annulus.
7. Calculate the pressure drop in the pipe.
8. Determine and optimize bit hydraulics.

The flow charts and accompanying explanations present the calculations needed to perform the hydraulics analysis. They are adapted from API RP 13D, dated June, 1995.

Annular Pressure Drop and ECD

Step #1. Draw hole geometry showing all casing IDs, hole size, and drill string IDs and ODs. See Figure 4-1.

Step #2. Calculate the fluid velocity for the first geometry interval, where

V_a = annular fluid velocity for the interval (ft/sec),

Q = volumetric flow (pump) rate (gal/min),

D_2 = hole diameter (in.),

D_1 = outside diameter of the drill pipe (in.).

Step #3. A. Calculate the n value (flow behavior index) for the interval, where

n_a = annular flow behavior index (dimensionless),

θ_{300} = V-G meter, 300-rpm dial reading,

θ_3 = V-G meter, 3-rpm dial reading.

Step #3. B. Calculate the K value (consistency factor) for the annular interval, where

K_a = annular consistency factor (poise),

θ_{600} = V-G meter, 600-rpm dial reading.

Step #4. Calculate the effective viscosity μ_e in the annulus, where

μ_{ea} = annular effective viscosity (cp).

Step #5. Calculate the Reynolds (Re) for the annular interval, where

Re_a = Annular Reynolds number (dimensionless),

ρ = fluid density (lbs/gal).

Step #6. A. Calculate the Reynolds number for the change from laminar to transitional flow for the interval, where

Re_L = the laminar to transitional flow Reynolds number (dimensionless).

Step #6. B. Calculate the Reynolds number for the change from transitional to turbulent flow for the interval, where

Re_T = the transitional to turbulent flow Reynolds number (dimensionless).

Step #7. If $Re_a < Re_L$, use the laminar flow equation to calculate the friction factor.

- If $Re_a > Re_T$, use the turbulent flow equation to calculate the friction factor.
- If $Re_L < Re_a < Re_T$, use the transitional flow equation to calculate the friction factor, where f_a = the annular Fanning Friction Factor (dimensionless).

Step #8. Calculate the pressure drop (P) for the interval, where

P_a = the interval pressure drop (psi),

L = the length of the interval (feet).

Step #9. Steps 2 through 8 must be repeated for each different annular geometry.

Step #10. Calculate the total annular pressure loss (P_{aT}) in psi by summing the individual pressure drops calculated for each interval.

Step #11. Converts the total annular pressure loss to equivalent circulating density (ECD), where

ECD = equivalent circulating density (lbs/gal).

Critical Velocity and Pump Rate

Step #1. For the first interval, calculate the fluid velocity for transition from laminar flow. This is generally termed the critical velocity (V_c) and is calculated as ft/sec in the equation. See Figure 4-2.

Step #2. Calculate the critical velocity for each annular geometry.

Step #3. Compare each interval's critical velocity to its annular velocity (V_a, calculated in step #2 in Figure 4-1).

Step #4. For each V_a that exceeds V_c, calculate the maximum pump rate that will cause the transition. This is called the critical flow rate (Q_c) for that interval and is reported in gal/min. Staying below this pump rate will ensure that the fluid flow through the annular interval remains laminar.

Figure 4-1 Annular Pressure Drop and ECD

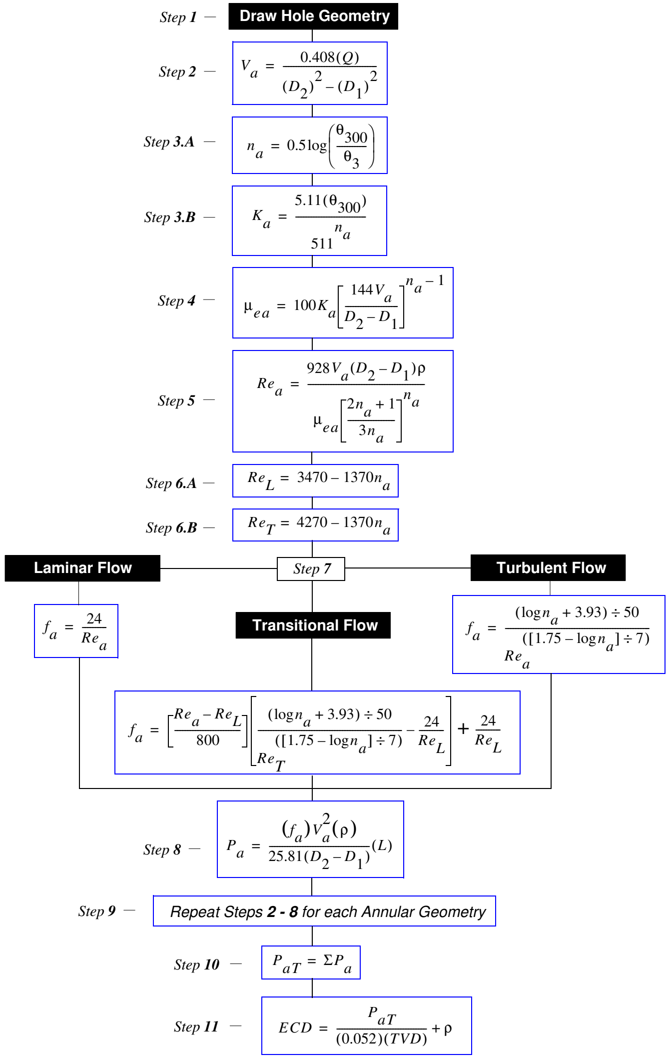
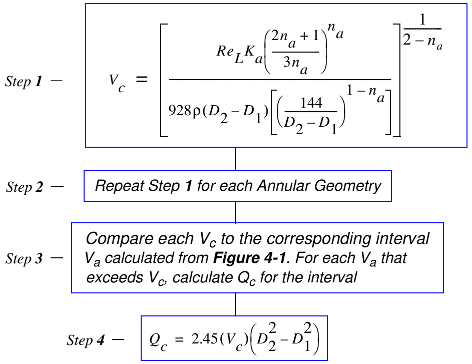


Figure 4-2 Critical Velocity and Pump Rate



Drill String Pressure Drop

Step #1. Calculate the fluid velocity in the drill pipe (see Figure 4-3), where

V_p = pipe fluid velocity (ft/sec),

Q = volumetric flow (pump) rate (gal/min),

D = pipe inside diameter (I.D.) (in.).

Step #2. A. Calculate the n value (flow behavior index) for the interval, where

n_p = pipe flow behavior index (dimensionless),

θ_{600} = V-G meter, 600-rpm dial reading,

θ_{300} = V-G meter, 300-rpm dial reading.

Step #2. B. Calculate the K value (consistency factor) for the annular interval, where

K_p = pipe consistency factor (poise),

θ_{600} = V-G meter, 600-rpm dial reading.

Step #3. Calculate the effective viscosity (μ_e) in the pipe, where

μ_{ep} = pipe effective viscosity (cp).

Step #4. Calculate the Reynolds (Re) for the pipe interval, where

Re_p = pipe Reynolds number (dimensionless),

ρ = fluid density, lbs/gal.

Step #5. A. Calculate the Reynolds number for the change from laminar to transitional flow for the interval, where

Re_L = the laminar to transitional flow Reynolds number (dimensionless).

Step #5. B. Calculate the Reynolds number for the change from transitional to turbulent flow for the interval, where

Re_T = the laminar to transitional flow Reynolds number (dimensionless).

Step #6. If $Re_p < Re_L$, use the laminar flow equation to calculate the friction factor.

- If $Re_p > Re_T$, use the turbulent flow equation to calculate the friction factor.
- If $Re_L < Re_p < Re_T$, use the transitional flow equation to calculate the friction factor, where f_p = the pipe Fanning Friction Factor (dimensionless).

Step #7. Calculate the pressure drop (P) for the interval, where

P_p = the pipe pressure drop (psi),

L = the length of the pipe section (feet).

Step #8. Steps 2 through 8 must be repeated for each different pipe internal diameter (I.D.).

Step #9. Calculate the total pipe pressure loss (P_{pT}) in psi by summing the individual pressure drops calculated for each pipe I.D.

Figure 4-3 Drill String Pressure Drop

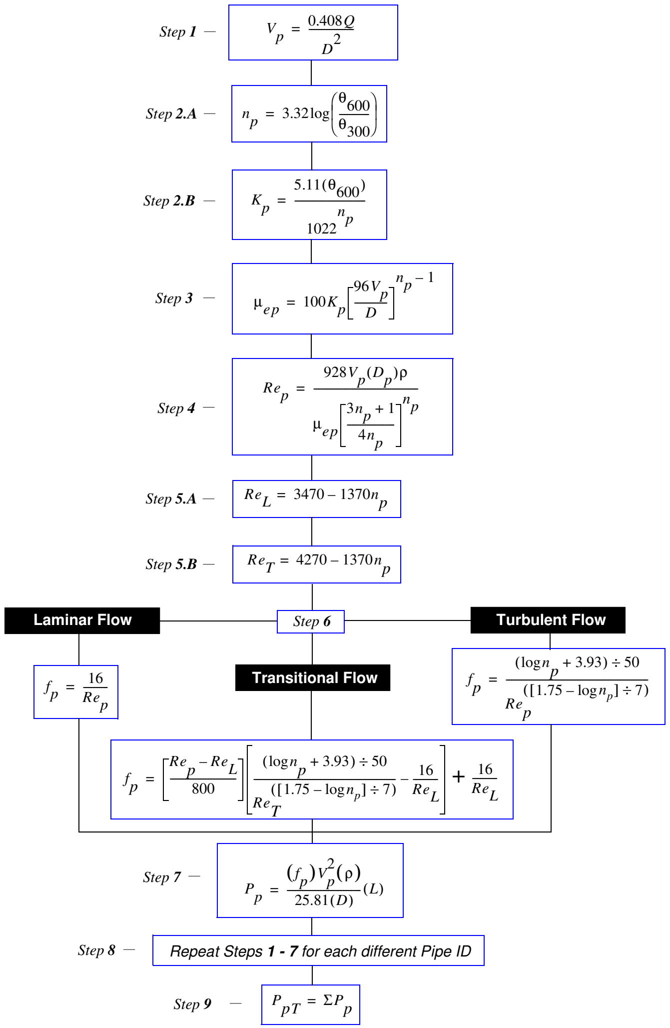
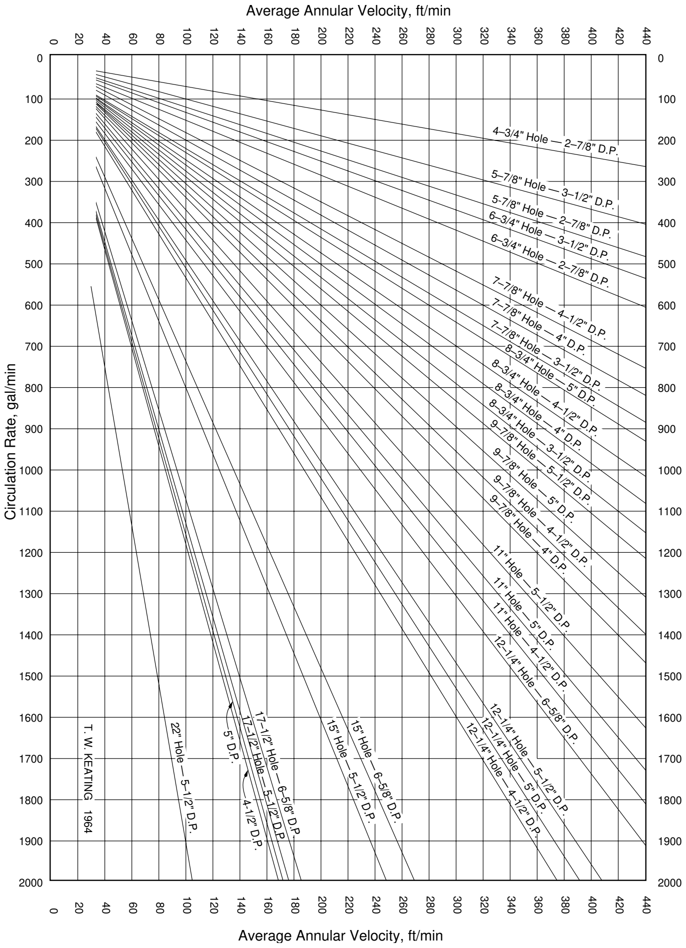


Figure 4-4 Average Annular Fluid Velocities for Various Circulation Rates, Hole Sizes, and Drillpipe Sizes



Swab and Surge Pressures

When the drillstring is run into the hole, the friction of the drilling fluid moving against the pipe causes the bottom of the hole to experience a pressure increase. This pressure increase is termed the *surge pressure*. Conversely, when the pipe is tripped out of the hole, there will be a decrease in the total pressure that the borehole experiences. The decrease is termed the *swab pressure*.

Both pressures are especially important in wells with a small margin between pore pressure and fracture pressure. Running the pipe into the hole too fast may lead to fracturing the wellbore and loss of circulation. Tripping out too rapidly may lead to the influx of formation fluids (kicks), excessive fill on trips, and other wellbore instability problems.

Swab and surge pressure calculations are made by converting the tripping speed of the pipe into an annular velocity. This annular velocity is used to calculate the annular pressure drop (see Figure 4-1). The total annular pressure drop experienced by running the pipe is converted to an equivalent fluid density (EMW). The EMW can then be compared to the fracture fluid weight or the fluid weight needed to keep the hole open and control subsurface pressures to determine the effect of the pipe movement on the well. Figure 4-5 is a flow chart for the calculation of swab and surge pressures.

Step #1. Determine the average speed of pipe movement (V_{pm}). Either of two methods can be used (see Figure 4-5).

Method 1

- V_{pm} = average pipe movement speed, ft/min
- L_s = stand length, feet
- t = time from slips to slips, seconds

Method 2

- L_j = joint length, feet
- t = joint time through rotary table, seconds

Step #2. Calculate the equivalent fluid velocity in the annulus (V_m) for the first geometry interval, where

V_m = equivalent fluid velocity for the interval (ft/min),

D_2 = hole diameter (in.),

D_1 = outside diameter of the drill pipe (in.).

Step #3. A. If the drilling fluid's rheological properties have changed since the last annular hydraulics analysis, calculate a new annular n value (flow behavior index) for the interval, where

n_a = annular flow behavior index (dimensionless),

θ_{300} = V-G meter, 300-rpm dial reading,

θ_3 = V-G meter, 3-rpm dial reading.

Step #3. B. If the drilling fluid's rheological properties have changed since the last annular hydraulics analysis, calculate a new annular K value (consistency factor) for the annular interval, where

K_a = annular consistency factor (poise),

θ_{600} = V-G meter, 600-rpm dial reading.

Note: *If the fluid's properties have not changed, use the n and K values previously calculated. Go to Step 4.*

Step #4. Calculate the new effective viscosity (μ_e) in the annulus, using V_m, where

μ_{ea} = annular effective viscosity (cp).

Step #5. Calculate the Reynolds (Re) for the annular interval using the new μ_{ea} and V_m , where

Re_a = Annular Reynolds number (dimensionless),

ρ = fluid density (lbs/gal).

Step #6. A. If the fluid's rheological properties have changed since the last hydraulics analysis, calculate the Reynolds number for the change from laminar to transitional flow for the interval, where

Re_L = the laminar to transitional flow Reynolds number (dimensionless).

Step #6. B. Calculate the Reynolds number for the change from transitional to turbulent flow for the interval, where

Re_T = the transitional to turbulent flow Reynolds number (dimensionless).

If the fluid's properties have not changed, use the previously calculated values and proceed with Step 7.

Step #7. If $Re_a < Re_L$, use the laminar flow equation to calculate the friction factor.

- If $Re_a > Re_T$, use the turbulent flow equation to calculate the friction factor.
- If $Re_L < Re_a < Re_T$, use the transitional flow equation to calculate the friction factor, where f_a = the annular Fanning Friction Factor (dimensionless).

Step #8. Calculate the pressure drop (P) for the interval, where

P_a = the interval pressure drop (psi),

L = the length of the interval (feet).

Step #9. Steps 2 through 8 must be repeated for each different annular geometry.

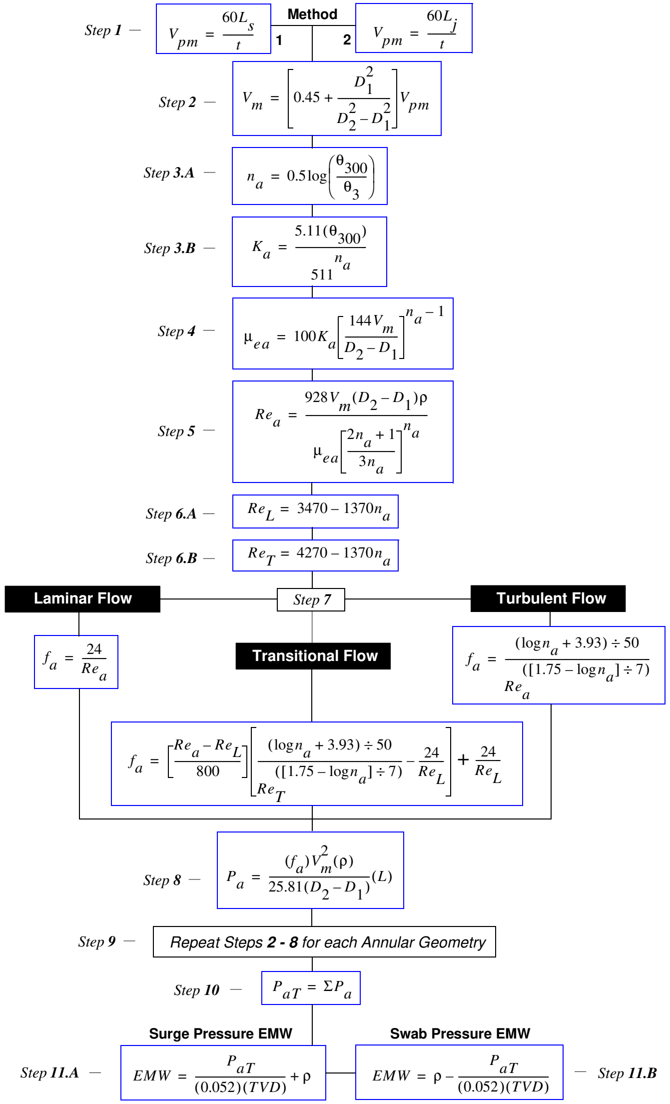
Step #10. Calculate the total annular pressure loss (P_{aT}) in psi by summing the individual pressure drops calculated for each interval.

Step #11A. If running into the hole, calculate the equivalent fluid density due to the surge pressure by adding the total annular pressure loss density equivalent to the fluid density, where

EMW = equivalent fluid density (lbs/gal).

Step #11B. If pulling out of the hole, calculate the equivalent fluid density due to the surge pressure by subtracting the total annular pressure drop density equivalent from the fluid density.

Figure 4-5 Swab and Surge Pressure



Slip Velocity and Hole Cleaning

A major function of the drilling fluid is to transport drill cuttings from the bottom of the hole to the surface where they can be removed. Poor hole cleaning can result in severe operational problems including:

- High torque and drag
- Reduced rate of penetration
- Stuck pipe
- Difficulty running casing
- Primary cementing failures.

The ability of the fluid to clean the hole is dependent upon the rheology and density of the fluid, its flow rate, and the size of the cutting. For any size particle (cutting), the upward movement of the particle with the fluid flow will be partially negated by the effect of gravity that is promoting the settling of the particle. The settling rate is termed the *slip velocity* (V_s). By comparing V_s to the annular velocity (V_a) in the interval, the *net particle transport* time (NPT) for the particle and the *annular transport time* (ATT) can be calculated. These values will give the engineer the minimum time required to transport a cutting to the surface. Figure 4-6 is a flow chart for the calculation of slip velocity, NPT and ATT.

Step 1: From the annular hydraulics analysis for each interval, determine if the fluid is in laminar or turbulent flow. If the fluid is in laminar flow, continue with Step 2 to calculate the slip velocity. If the fluid is in turbulent flow, skip to Step 7.

Step 2: Calculate the boundary layer shear rate (γ_B), where

γ_B = boundary layer shear rate ($\sec^{-1}$),

Dc = particle diameter (in.),

ρ = fluid density (lb/gal).

Step 3: Calculate the shear stress (τ_p) developed by the particle, where

τ_p = particle shear stress (lb/100 ft^2),

T = particle thickness (in.).

Step 4: Calculate the shear rate developed by the particle (γ_p) using τ_p and the low shear rate n and K values for the drilling fluid, where

γ_p = the particle shear rate (sec^{-1}),

n_a = the low shear rate annular behavior index from Figure 4-1,

K = the annular consistency factor from Figure 4-1.

Step 5: Compare γ_p to γ_B to determine which equation to use to calculate the slip velocity.

Step 6: Calculate the slip velocity and skip to Step 9.

Step 7: For any interval in turbulent flow, use equation B-1 in Figure 4-6 to calculate the shear stress developed by the particle.

Step 8: Use equation B-2 in Figure 4-6 to calculate the slip velocity.

Step 9: Calculate the NPT and ITT, where

NPT = net particle transport (ft/min),

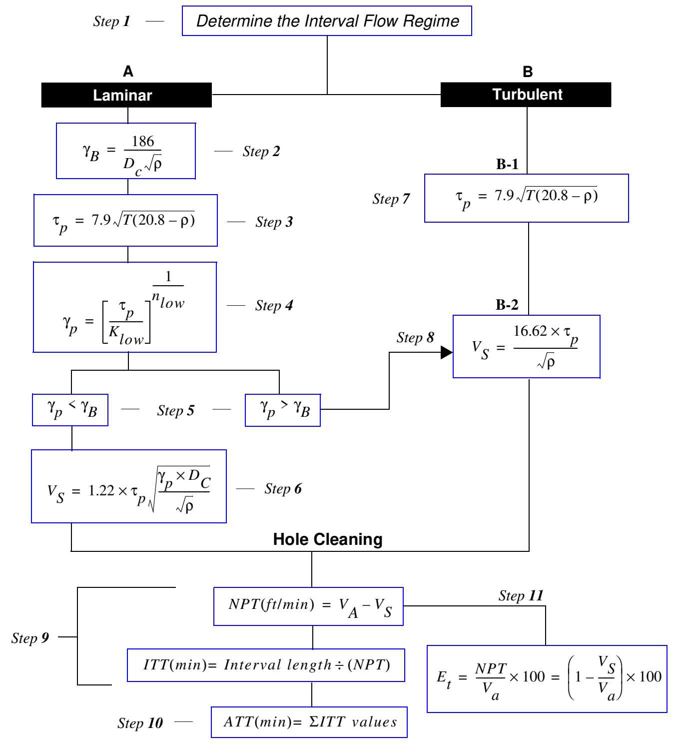
V_A = the interval annular velocity (ft/min) (= V_a from Figure 4-1 multiplied by 60 sec/min).

Step 10: Calculate the ATT by summing the individual ITT values.

Step 11: Calculate the transport efficiency (E_t) in percent for any interval by dividing the NPT by the interval's annular velocity and multiplying the quotient by 100%. The higher the transport efficiency, the higher the fluid's carrying capacity and the faster the cuttings are removed from the wellbore.

Note: *Hole cleaning in highly deviated and horizontal wells proceeds by different mechanisms than in vertical wells. The above calculations will not guarantee acceptable hole cleaning in those situations. The computer program DEAP should be used to evaluate hole cleaning in these situations.*

Figure 4-6 Slip Velocity and Hole Cleaning



Cuttings Concentration

When drilling the well, the rate of penetration may generate a larger volume of cuttings than can be circulated out of the wellbore in one circulation. This results in a build up of cuttings in the drilling fluid in the annulus. The concentration of cuttings (C_a) in the fluid in any annular interval can be calculated by using the following equations. Depending upon the formations drilled, a C_a > 6% to 8% volume can result in hole cleaning problems such as mud rings and pack-off.

1. For cuttings concentration (vol %), calculate

$$C_a = \frac{(ROP)\,D^2}{14.71\,E_t\,Q} \times 100$$

where

C_a = cuttings concentration (vol %),

D = hole diameter (in.),

E_t = interval transport efficiency from Figure 4-6, expressed as a decimal fraction,

Q = flow rate (gal/min),

ROP = rate of penetration (ft/hr).

2. The effective fluid weight (lb_m/gal) resulting from the accumulation of cuttings in the annulus can be calculated by

$$\rho_e = (S.G._c)(8.34)\left(\frac{C_a}{100}\right) + \rho\left(1 - \frac{C_a}{100}\right)$$

where

ρ_e = effective fluid weight due to cuttings concentration (lb_m/gal),

$S.G._c$ = specific gravity of the cuttings,

C_a = cuttings concentration (vol %),

ρ = fluid density (lb_m/gal).

Bit Hydraulics Analysis

This sequence of calculations is designed to allow the technician to quickly and accurately analyze various parameters of existing bit hydraulics. Certain *rules of thumb* are given as a guideline for the novice in interpreting the resultant data. It should be remembered that these “rules” are not absolutes and do not apply in every instance. Any time the *maximum values* are exceeded, there is a possibility of reducing bit life.

1. **ΔP_b** *(Pressure Loss at Bit)*: This equation gives that amount of the total circulating pressure that is consumed at the bit. **RULE**: Good hydraulics normally result when between 50% to 65% of surface pressure is utilized at the bit.

2. **HHP_b** *(Hydraulic Horsepower at the Bit)*: Calculates the total hydraulic horsepower available across the face of the bit. Hydraulic horsepower is a measure of work done by moving fluid.

3. **HHP_b/in^2** *(Hydraulic Horsepower per Square Inch of the Bit Area)*: Converts the total Hydraulic Horsepower at the bit to that available per square inch of the bit face area. **RULE**: A general range of HHP_b/in^2 for optimized drilling is 2.5 to 5.0.

4. **V_n** *(Bit Nozzle Velocity)*: Calculates the velocity with which the fluid moves through the bit nozzles at the current flow rate. **RULE**: The nozzle velocity ranges between 250 to 450 ft/sec for most drilling operations.

5. **I.F.** *(Impact Force)*: Gives the total lbs force exerted at the formation face by the fluid flowing through the bit nozzles. **RULE**: For most operations, Impact Force is maximized when 50% of the surface pressure is expended at the bit.

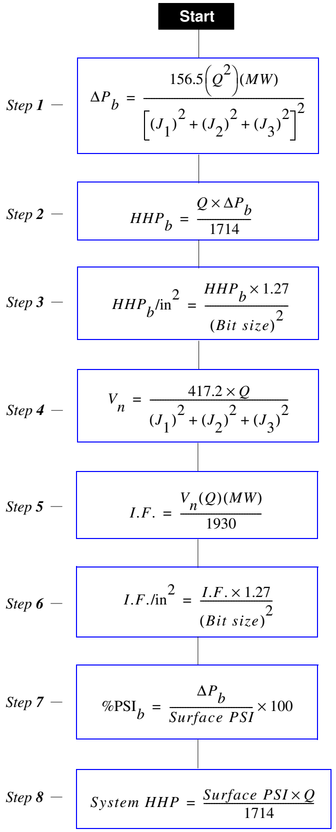
6. **I.F./In^2** *(Impact Force per Square Inch of the Bit Area)*: Converts the total Impact Force to that available per square inch of bit face area.

7. **%PSI$_b$** *(Percent of Pressure Lost at Bit)*: Gives the percentage of total surface pressure that is expended at the bit. This is the complementary parameter of ΔP_b in Step 1.

8. **System HHP** *(Total Hydraulic Horsepower of the Circulating System)*: Calculates the total hydraulic horsepower expended throughout the entire circulating system. Used as a benchmark of the efficiency of the hydraulics program.

Note: *The % of Hydraulic Horsepower at the bit is equal to the % pressure loss at the bit.*

Figure 4-7 Bit Hydraulics Analysis



Step **1** —

$$\Delta P_b = \frac{156.5\left(Q^2\right)(MW)}{\left[(J_1)^2 + (J_2)^2 + (J_3)^2\right]^2}$$

Step **2** —

$$HHP_b = \frac{Q \times \Delta P_b}{1714}$$

Step **3** —

$$HHP_b/\mathrm{in}^2 = \frac{HHP_b \times 1.27}{(Bit\ size)^2}$$

Step **4** —

$$V_n = \frac{417.2 \times Q}{(J_1)^2 + (J_2)^2 + (J_3)^2}$$

Step **5** —

$$I.F. = \frac{V_n(Q)(MW)}{1930}$$

Step **6** —

$$I.F./\mathrm{in}^2 = \frac{I.F. \times 1.27}{(Bit\ size)^2}$$

Step **7** —

$$\%\mathrm{PSI}_b = \frac{\Delta P_b}{Surface\ PSI} \times 100$$

Step **8** —

$$System\ HHP = \frac{Surface\ PSI \times Q}{1714}$$

Miscellaneous “Rules”

- The minimum flow rate to clean the hole is 30 gpm per inch of the hole diameter (i.e., 8½" hole requires 255 gpm).
- The maximum flow rate is 50 gpm per inch of hole diameter.

Jet Selection

Once the bit hydraulics have been established, they can be optimized for the particular drilling situation. Bit hydraulics optimization is begun by establishing the maximum pressure drop across the bit that can be achieved with the equipment and drilling fluid in use. The calculations in Figure 4-8 are used to size the bit’s nozzles to provide maximum hydraulic horse power at the bit for optimum bit and hole cleaning, maximizing the impact force of the fluid on the formation for increased rate of penetration, or providing for a compromise between the two.

Step #1. Compare the rig’s surface equipment to the equipment types described in Table 4-1. Select the type number (1,2,3 or 4) that most closely matches the rig’s equipment.

Type	Stand Pipe		Hose		Swivel		Kelly	
	Length (ft.)	I.D. (in.)	Length (ft.)	I.D. (in.)	Length (ft.)	I.D. (in.)	Length (ft.)	I.D. (in.)
1	40	3	45	2	4	2	40	2¼
2	40	3½	55	2½	5	2¼	40	3¼
3	45	4	55	3	5	2¼	40	3¼
4	45	4	55	3	6	3	40	4

Table 4-1 Surface Equipment Types

Step #2. Using the equipment type number and the flow rate, determine the pressure loss through the surface equipment from Table 4-2, where

P_S = the surface system pressure loss (psi).

Table 4-2 Pressure Loss through Surface Equipment (psi)

GPM	Surface Equipment Type				GPM	Surface Equipment Type			
	1	2	3	4		1	2	3	4
50	2	1	–	–	410	137	49	30	20
60	3	1	–	–	420	144	51	31	21
70	5	1	1	–	430	150	54	33	22
80	6	2	1	1	440	157	56	34	23
90	8	3	1	1	450	164	59	36	24
100	10	3	2	1	460	170	61	37	25
110	11	4	2	1	470	177	64	39	26
120	14	5	3	2	480	184	66	40	27
130	16	5	3	2	490	192	69	42	28
140	18	6	4	2	500	199	71	43	29
150	21	7	4	3	510	207	74	45	31
160	24	8	5	3	520	214	77	47	32
170	26	9	5	4	530	222	80	48	33
180	29	10	6	4	540	230	82	50	34
190	33	11	7	4	550	238	85	52	35
200	36	13	8	5	560	246	88	54	37
210	39	14	8	6	570	254	91	56	38
220	43	15	9	6	580	262	94	57	39
230	47	16	10	7	590	271	97	59	40
240	50	18	11	7	600	280	100	61	42
250	55	19	12	8	610	288	104	63	43
260	59	21	13	8	620	297	107	65	44
270	63	22	14	9	630	306	110	67	46
280	67	24	14	10	640	315	113	69	47
290	72	26	15	10	650	325	117	71	48
300	77	27	17	11	660	334	120	73	50
310	82	29	18	12	670	343	123	75	51
320	87	31	19	13	680	353	127	77	53
330	92	33	20	13	690	363	130	79	54
340	97	35	21	14	700	373	134	82	56
350	102	37	22	15	710	383	137	84	57
360	108	39	23	16	720	393	141	86	59
370	114	41	25	17	730	403	145	88	60
380	119	43	26	18	740	413	148	91	62
390	125	45	27	18	750	424	152	93	63
400	131	47	29	19	760	434	156	95	65

Table 4-2 Pressure Loss through Surface Equipment (psi) (continued)

GPM	Surface Equipment Type				GPM	Surface Equipment Type			
	1	2	3	4		1	2	3	4
770	445	160	98	66	1140	–	332	203	138
780	456	164	100	68	1150	–	338	206	140
790	467	168	102	70	1160	–	343	210	143
800	478	172	105	71	1170	–	349	213	145
810	489	176	107	73	1180	–	354	216	147
820	500	180	110	75	1190	–	360	220	150
830	512	184	112	76	1200	–	366	223	152
840	523	188	115	78	1210	–	371	227	154
850	535	192	117	80	1220	–	377	230	157
860	547	197	120	82	1230	–	383	234	159
870	559	201	123	83	1240	–	389	237	162
880	571	205	125	85	1250	–	394	241	164
890	583	209	128	87	1260	–	400	244	167
900	595	214	131	89	1270	–	406	248	169
910	607	218	133	91	1280	–	412	252	171
920	620	223	136	93	1290	–	418	255	174
930	632	227	139	94	1300	–	424	259	177
940	645	232	142	96	1310	–	430	263	179
950	658	237	144	98	1320	–	437	267	182
960	671	241	147	100	1330	–	443	270	184
970	684	246	150	102	1340	–	449	274	187
980	697	251	153	104	1350	–	455	278	189
990	710	256	156	106	1360	–	461	282	192
1000	724	260	159	108	1370	–	468	286	195
1010	–	265	162	110	1380	–	474	290	197
1020	–	270	165	112	1390	–	481	294	200
1030	–	275	168	114	1400	–	487	297	203
1040	–	280	171	116	1410	–	494	301	205
1050	–	285	174	119	1420	–	500	305	208
1060	–	290	177	121	1430	–	507	309	211
1070	–	295	180	123	1440	–	513	314	214
1080	–	300	183	125	1450	–	520	318	216
1090	–	306	187	127	1460	–	527	322	219
1100	–	311	190	129	1470	–	533	326	222
1110	–	316	193	131	1480	–	540	330	225
1120	–	321	196	134	1490	–	547	334	228
1130	–	327	200	136	1500	–	554	338	230

Step #3. Establish the pressure available for nozzle selection. This is the difference between the operating pressure limit of the system and the actual system pressure losses, where

P_B = the bit pressure loss (psi),

P_{MAX} = maximum standpipe pressure (psi),

P_{aT} = total annular pressure loss (Figure 4-1, Step 10) (psi),

P_{pT} = total drill string pressure loss (Figure 4-3, Step 9) (psi).

Step #4. Calculate the optimum total nozzle area required, where

A_t = optimum total nozzle area (in.^{2}),

C = a constant:

- 0.65 for maximum HHP
- 0.48 for maximum impact force
- 0.59 for the HHP-impact force compromise.

Step #5. Use the jet size algorithms to calculate each nozzle size, where

J_1, J_2, J_3, etc. = the jet size of jet #1, jet #2, etc. in 32nd of an inch (rounded to *the nearest whole number*),

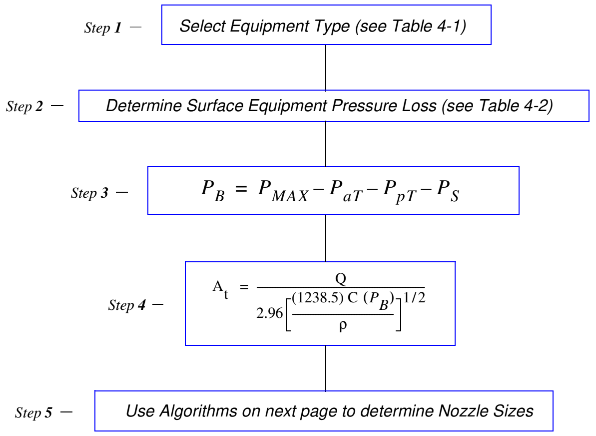
N = the total number of jets.

Note: *The flow rate (Q) affects the entire hydraulics program. Frequently, increasing flow rate produces a larger effect on hydraulics than optimizing at a particular flow rate. Changing flow rate depends upon the capabilities of the fluid pumps in use, the pressure ratings of the surface equipment, and the effect of the higher pump rate on bore hole stability and ECD. These factors must be considered as a group when changes to the hydraulics program are anticipated.*

Note: *Modifying the drilling fluid's properties can also have a dramatic effect on hydraulics. Generally, decreasing viscosity will decrease the pipe and annular pressure drops, allowing for an increase in flow rate at the same standpipe pressure. Increasing viscosity will have the opposite effect. The impact of changing rheology on cuttings transport and suspension must be assessed in conjunction with the change in hydraulics.*

Note: *Boundary layer lubricants can be added to the fluid system. These lubricants, in addition to reducing torque and drag, may also reduce the total system pressure loss by modifying the flow regime at the interface of the pipe and fluid without dramatically affecting the drilling fluid's rheological properties. Unfortunately, there is no good way to test for this effect prior to the lubricant's use.*

Figure 4-8 Jet Optimization



Algorithms for jet sizes ($^1/_{32}$ in.) are as follows.

$$J_1 = \left[\frac{1303.797}{N} A_t\right]^{1/2}$$

$$J_2 = \left[\frac{1303.797}{N-1}\left(A_t - \frac{J_1^2}{1303.797}\right)\right]^{1/2}$$

$$J_3 = \left[\frac{1303.797}{N-2}\left(A_t - \frac{J_1^2 + J_2^2}{1303.797}\right)\right]^{1/2}$$

$$J_4 = \left[\frac{1303.797}{N-3}\left(A_t - \frac{J_1^2 + J_2^2 + J_3^2}{1303.797}\right)\right]^{1/2}$$

$$J_{N-3} = \left[\frac{1303.797}{4}\left(A_t - \frac{J_1^2 + \ldots + J_{N-4}^2}{1303.797}\right)\right]^{1/2}$$

$$J_{N-2} = \left[\frac{1303.797}{3}\left(A_t - \frac{J_1^2 + \ldots + J_{N-3}^2}{1303.797}\right)\right]^{1/2}$$

$$J_{N-1} = \left[\frac{1303.797}{2}\left(A_t - \frac{J_1^2 + \ldots + J_{N-2}^2}{1303.797}\right)\right]^{1/2}$$

$$J_N = \left[\frac{1303.797}{1}\left(A_t - \frac{J_1^2 + \ldots + J_{N-1}^2}{1303.797}\right)\right]^{1/2}$$

Pressure Control

Introduction

Control of formation pressures is one of the primary functions of drilling fluids. The hydrostatic pressure exerted by the fluid column is considered the most important method of controlling formation pressure. Whenever formation pressure exceeds the total pressure exerted on the formation, fluids may enter the wellbore causing a kick.

Early recognition of a kick and prompt initiation of control procedures are the keys to successful well control. Casing pressures resulting from a kick depend upon the volume and density of the invading fluid, as well as the differential between the formation pressure gradient and fluid gradient.

Terminology

Pressure Gradient (psi/ft)

This is the pressure exerted by each foot of a fluid. The unit for pressure gradient is psi/ft. To determine pressure gradient, the fluid weight is multiplied by a conversion factor,

$$psi/ft = MW_1 \times 0.052 \qquad (4\text{-}1)$$

where

MW_1 = fluid density (lb_m/gal).

Normal Formation Pressure

When a formation is deposited, fluids in that formation, mostly water, occupies the pore spaces. As new sediments are deposited above, a formation compacts. Compaction reduces the volume of the pore spaces. If the excess fluid occupying the pore spaces can escape to overlying formations during compaction, the formation will contain only the hydrostatic pressure exerted by the water or fluid that remains in the pores. This is normal formation pressure.

Normal Formation Pressures

- Marine basins – 0.465 psi/ft (equal to 8.9 ppg salt water)
- Inland areas – 0.433 psi/ft (equal to 8.33 ppg water)

Abnormal Formation Pressure

When fluids are sealed within a formation (due to impermeability) and are unable to escape, they then support part of the weight of the overburden. Therefore, as the depth increases, the overburden load increases and formation pressure increases.

Hydrostatic Pressure

The pressure which is exerted due to the density and true vertical height of a column of fluid. TVD is always used in pressure calculations.

$$\text{Hydrostatic Pressure} = 0.052 \times MW_1 \times TVD \tag{4-2}$$

Equivalent Fluid (Mud) Weight

The total of all pressures (hydrostatic pressure, circulating pressure, and imposed pressure) exerted on a formation at a given depth, expressed in terms of fluid weight, lb_m/gal. P_S is the total pressure at the source which includes circulating and imposed pressures.

$$EMW = \frac{P_S}{0.052 \times TVD} + MW_1 \tag{4-3}$$

Fracture Gradient

The pressure required to initiate fracture development in a formation at a specific depth, psi/ft.

Calculations of fracture gradient are based on the integrity of the rock structure. When the fracture gradient of a formation is exceeded, loss of circulation occurs.

Note: *If the fracture gradient of an area is unknown, then a leak-off test can be run to establish the fracture gradient.*

Leak-Off Test

A test to determine the maximum pressure integrity of exposed formations at the casing shoe.

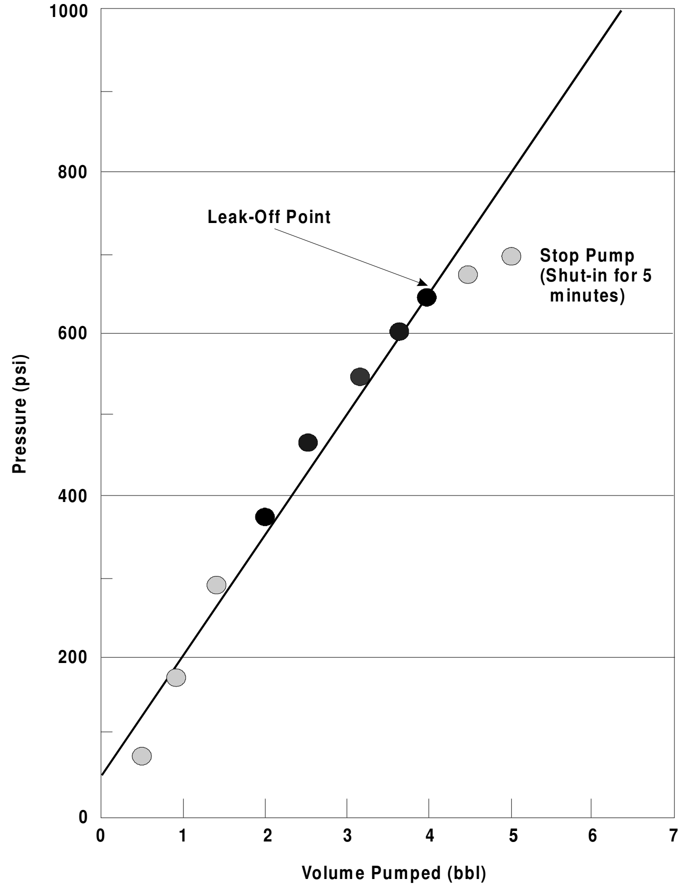
The procedure is as follows.

1. Drill 10 to 20 feet of new formation below the casing seat and circulate the hole clean.
2. Close the well in; pump at low rate (0.2 to 0.5 bbl/min).

Note: *Low pump rates are needed to better evaluate the pressure build-up.*

3. The first three volume increments will establish the pressure profile. The pressure plotted (see Figure 4-9) will be the drill pipe pressure after the pump has been shut down for one minute.

Figure 4-9 Leak-Off Test Pressure Profile



4. The point at which the pressure fails to increase proportionately with the volume pumped (two consecutive shut-in pressures deviate from the straight line, as shown in Figure 4-9) is considered the leak-off point. Record the surface pressure at this point.
5. Shut-in the well for 5 minutes. Bleed off the pressure in one barrel increments. Record the bleed-back volume to establish how much fluid has been lost to the formation. Final pressure will be the 5-minute recorded pressure.
6. Once the surface pressure at which leak-off occurs has been established, the fracture fluid weight (F_{mw}) can be determined by the following calculation.

$$F_{mw},\ lb_m/gal = MW_1 + \frac{P_S}{0.052 \times TVD} \qquad (4\text{-}4)$$

Note: *Due to the high degree of compressibility/ expansion of diesel oils, mineral oils, and synthetic-base fluids, it is important these types of fluids reach a steady state temperature profile prior to performing a Leak-Off test or Pressure Integrity test. The compressibility/expansion factors for each of these fluids can be calculated from empirical formulas or PVT tables.*

Pressure Integrity Test

A variation of the leak-off test is the pressure integrity test (PIT). The mechanical procedure is the same. The difference is that the total pressure (hydrostatic and imposed) exerted on the formation is equivalent to the maximum anticipated fluid density (MW_2) plus a safety factor which may be required in certain areas. This is accomplished by imposing some surface pressure (in addition to the hydrostatic pressure) on the fluid column.

Formula for the surface pressure to be applied (P_S) is

$$P_S = (MW_2 - MW_1)\ 0.052 \times TVD_S \qquad (4\text{-}5)$$

Kick Recognition

Some occurrences that may be associated with a kick are:

1. Drilling break (increase or change in drilling rate)

2. Increase in flow rate
3. Increase in pit volume
4. Circulating pressure drop
5. Well flowing with pumps off
6. Increase in chloride content of fluid at the flowline
7. Increase in temperature of fluid at flowline.
8. Hole not taking proper quantity of fluid while tripping pipe

Determining Shut-in Drillpipe Pressures (SIDP)

Fluid inside the drillpipe will normally not be contaminated, therefore, the pressure on the stand pipe gauge plus the hydrostatic pressure of the fluid column in the drillpipe will equal the formation pressure. Do the following to determine shut-in drillpipe pressure.

1. Read directly from gauge if there is no back pressure valve in the string.
2. If a back pressure valve is in the string, then:
    - Start pump slowly, continue until fluid moves or pump pressure increases suddenly.
    - Watch casing pressure; stop pump when the annular pressure starts to increase.
    - Read drillpipe pressure at this point.
    - If casing pressure increases above original pressure, this would indicate trapped pump pressure. The amount of the increase in casing pressure must then be subtracted from the shut-in drillpipe pressure. This procedure should be repeated until the same value is reached two consecutive times.

    OR

    If predetermined slow rate and pressure have been recorded, then:

    - Open choke and start pump slowly, hold casing pressure at the same level as the shut-in casing pressure.

- Bring pump speed up to predetermined slow rate, keeping casing pressure constant.
- Read circulating pressure from stand pipe gauge, and subtract predetermined circulating pressure. The difference will be the amount of under balance or the shut-in drillpipe pressure.

Note: *This procedure is also outlined in the following section, Determining Initial Circulating Pressure.*

Determining Initial Circulating Pressure (ICP)

Surface BOP Stacks

1. A predetermined slow circulation rate (usually ½ the normal drilling rate) and corresponding pressure loss should be recorded each tour. (This is to compensate for any change in depth or fluid weight.) This recorded pressure, plus the shut-in drillpipe pressure, will equal the Initial Circulating Pressure (ICP).
2. If no predetermined slow rate has been recorded, the shut-in casing pressure can be used as a reference point. Open the choke slightly and bring the pump up to a slow rate while maintaining the original shut-in casing pressure at all times. When a satisfactory slow rate has been reached and the casing gauge still reads original pressure, the initial circulating pressure can be read from the drillpipe gauge.

Example A: (Surface Stacks)

Recorded slow-circulating pressure (Kill rate)	250 psi
Shut-in drillpipe pressure	+300 psi
Initial circulating pressure	550 psi

If no slow-circulating pressure is recorded, then:

- Open choke and begin pumping simultaneously.
- Bring pump speed up to kill rate while holding the casing pressure at the shut-in casing pressure (SICP).
- Read ICP from the drillpipe gauge.

Subsea BOP Stacks

1. This step is identical to the one for surface BOP equipment except the slow rate will need to be slower than the ½ rate recommended previously. This lower slow pump rate is needed to prevent excessive wellbore pressures when circulating through long choke lines.
2. A predetermined slow rate and choke line friction **must** be recorded *each tour* to compensate for changes in depth or fluid weight. This information is important because choke line friction will reduce shut-in casing pressure by the amount of choke line friction when circulating. This pressure restriction can be determined by circulating the well at the kill rate, through the choke line, and then circulating through the riser. The difference between these two pressures is the choke line friction.

An alternate method is to circulate down the kill line and back to the surface through the choke line when the BOPs are closed. The recorded pressure divided by two will result in choke line friction. The circulating casing pressure can be determined by the following method.

Example B: (Subsea Stacks)

Original shut-in casing pressure	350 psi
Choke line friction pressure	– 100 psi
Casing pressure to use when establishing initial circulating pressure	250 psi

If the choke line friction is greater than the shut-in casing pressure, it is not possible to balance formation pressure while circulating, even if the choke is fully open. This may occur even if circulation is conducted through the kill and choke lines simultaneously.

The inactive line pressure gauge can be used to monitor casing pressure and compensate for choke line friction pressure while bringing the pumps up to speed. Should both lines be used to reduce the choke line friction (CLF), and if the CLF exceeds shut-in casing pressure, then the choke will have to be fully opened when circulating.

Example C: (Subsea Stacks)

Original shut-in casing pressure	250 psi
Choke line friction pressure	– 350 psi
Casing pressure to use when establishing initial circulating pressure	0.0 psi

In the example above, an imbalance of 100 psi will be left over and must be compensated on the drill pipe pressure. This results in the following.

Example D: (Subsea Stacks)

Slow circulating rate (SCR)	350 psi
Shut-in drill pipe pressure	200 psi
Excess choke line friction	+100 psi
Circulating pressure to kill well	650 psi

Note: *This example results in a 100 psi overbalance. This overbalance can be minimized by recording several slow rates and using the slowest rate possible.*

3. An additional concern when circulating gas through a subsea stack is the formation of hydrates. Hydrate formation is precipitated by a combination of water, gas, temperature, pressure, and time. Should hydrate crystals form, the result could be a blockage in the well head and connecting lines. The prevention of hydrates is covered in **NEW-DRILL Fluids**, Chapter 2.

Fluid Weight Needed to Balance a Kick (MW_2)

Shut-in drillpipe pressure permits direct calculation of the fluid density (MW_2) needed to balance formation pressure.

$$MW_2, lb_m/gal = MW_1 + \frac{SIDP}{0.052 \times TVD} \qquad (4\text{-}6)$$

Determining Final Circulating Pressure (FCP)

The Wait and Weight and Concurrent methods of well killing require calculation of the *final slow-rate circulating pressure* with the new fluid weight in the hole. This Final Circulating Pressure (FCP) may be calculated as follows.

$$FCP = \frac{MW_2}{MW_1} \times SCR \qquad (4\text{-}7)$$

Well-Control Procedures

Procedure for Closing Well in While on Bottom

1. Position kelly and tool joint so that tool joints are clear of sealing elements.
2. Stop pumps; check for flow.
3. If flow is noted, close well in without delay.
4. Record shut-in drillpipe and casing pressures.
5. Record volume gain and mark pits.
6. Weigh fluid in suction pits.
7. Check blowout preventer and manifold for leaks.
8. Check flowline and choke exhaust for flow.
9. Check accumulator pressure.
10. Initiate well kill procedures.

Procedure for Closing Well in While Tripping

1. If a flow is detected, install and close a safety valve.
2. Position tool joints clear of the sealing elements and close annular preventer.
3. Install an inside preventer and open the safety valve.
4. Record casing pressure.
5. Check blowout preventer, stack, and manifold for leaks.
6. Check valves for correct position.
7. Check accumulator pressure.
8. Begin stripping to bottom.

Note: *The Mineral Management Service (MMS) requires the operator to monitor casing pressure as he shuts the well in. One way to comply with this is to shut the manifold off, keeping the remote choke line open. When shutting in the well, close in on the remote choke slowly and monitor the casing pressure as it builds.*

Note: *The number one priority is to get the well killed and this should be done with the bit on bottom.*

Control Methods

The three most common well-control methods maintain a constant bottomhole pressure on the wellbore while formation fluids are circulated to the surface. This is accomplished by using an adjustable choke which can be opened or closed to decrease or increase wellbore pressures.

The descriptions of the methods below assume that the pump rate stays constant and no changes occur in the circulating system (bit doesn't plug, drillpipe doesn't washout, etc.). In the event that pump rates change or a problem develops in the circulating system, choke adjustments may not maintain constant bottomhole pressures. A full discussion of these problems and how they are to be controlled can be found in the Baker Hughes INTEQ *Drilling Fluids Reference Manual*, **Pressure Prediction and Control**. A discussion of the three well-control methods follows.

Driller's Method

The driller's method of killing a well should be accomplished in two circulations. After the well has been shut-in and the pressures and kick volumes are recorded, the well is circulated to remove formation fluids from the wellbore. A balanced bottomhole pressure is maintained during this circulation utilizing a constant pump rate and a constant circulating drillpipe pressure to prevent further intrusion of formation fluids. *The drillpipe pressure is held constant by varying only the choke size.* If pressure on the drillpipe increases, the choke should be enlarged, and if pressure on the drillpipe decreases, the choke size should be decreased.

After the annulus has been circulated clear of invading fluids, the well may be shut-in and the surface tanks weighted to the density necessary to balance, or slightly overbalance, formation pressures. Casing pressure is then maintained constant as the heavy fluid is pumped to the bit. When the heavy fluid reaches the bit, note the drillpipe pressure. The choke is then adjusted to maintain this new

circulating pressure on the drill pipe for the remainder of the kill procedures.

Wait and Weight Method

After the well has been shut-in, complete the “Basic Data” section of the Well Control Kill Sheet, items **a - j**. (See Figure 4-11)

Slow-circulating pressures (item **i**) should have already been measured and recorded (see Determining Initial Circulating Pressure). After shut-in pressures have stabilized, record the kick information (items **k - m**). Next calculate items **n - q** from the previously recorded information. Use the kill sheet to plot a drillpipe pressure-reduction schedule and complete the chart showing pump strokes versus drillpipe pressure. (See Figure 4-11)

When the system is weighted up to the desired density (MW_2), initiate circulation. Hold the casing pressure constant [less Choke Line Friction (CLF) for subsea wells] until the pump reaches slow-circulating rate. At this point, adjust the choke to maintain the drillpipe pressure in accordance with the pumping schedule.

As the weighted fluid is pumped, the circulating pressure will decrease proportionately until the final circulating pressure (FCP) is reached when the new fluid (MW_2) reaches the bit. When the new fluid (MW_2) reaches the bit, the final circulating pressure (FCP) is maintained on the drill pipe (pump) pressure gauge until the well has been circulated free of kick fluid, and the new fluid (MW_2) has reached the surface.

A *completed* kill sheet is shown in Figure 4-10.

Concurrent Method

This is a modification of the Wait and Weight method. On the horizontal axis of the graph, divide fluid weight increase into equal increments, then draw a straight line from the initial circulating pressure to the final circulating pressure. Record fluid weight increases as they occur in the fluid tanks, noting the time or total circulating strokes. Add surface-to-bit travel time to this recorded time and reduce drillpipe pressure according to the pumping schedule, as the new fluid weights reach the bit.

WELL CONTROL SHEET

BASIC DATA

a. True Vertical Depth (TVD)..... *6100* ft.
b. Measured Depth (MD)........... *9100* ft.
c. Fluid (Mud) Weight................ *11.5* lb_m/gal
d. Drillpipe Volume..................... *162* bbl
e. Riser Volume......................... *n/a* bbl
f. Pump Output.......................... *0.143* bbl/stk
g. Drillpipe Strokes..................... *1133* stk
h. Strokes to Displace Rider...... *n/a* stk
i. Slow-Circulating Pressures (SCP)
Riser or Casing:
Pump #1: *800* psi @ *45* SPM
Pump #2: *800* psi @ *45* SPM
Choke Line (SUBSEA)
Pump #1: *n/a* psi @ *n/a* SPM
Pump #2: *n/a* psi @ *n/a* SPM
j. Maximum Allowable Casing Pressure
(Fracture Fluid Wt. – Present Fluid Wt.) × Casing Depth × 0.052
(*15.0* – *11.5*) × *3220* × 0.052 = *586* psi

KICK INFORMATION

k. Shut-In Drillpipe Pressure (SIDP)......................... *300* psi
l. Shut-In Casing Pressure (SICP)........................... *450* psi
m. Kick Volume.. *60* bbl

CALCULATE

n. Initial Circulating Pressure (ICP)

SCP	+	SIDP	=	ICP
800	+	*300*	=	*1100*

o. New Fluid (Mud) Weight (MW)

SIDP	÷	0.052	÷	Depth	+	Old MW	=	New MW
300	÷	0.052	÷	*6100*	+	*11.5*	=	*12.4* lb_m/gal

p. Final Circulating Pressure (FCP)

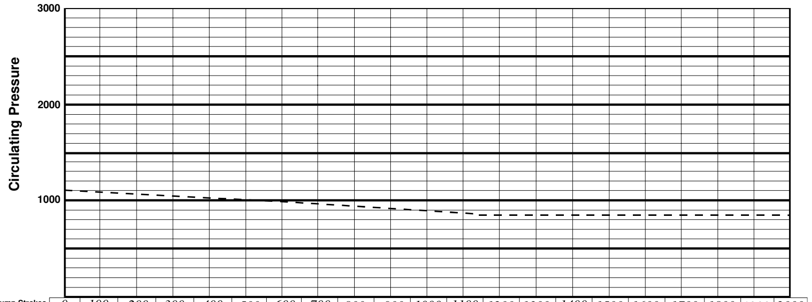
New MW	÷	Old MW	×	SCP	=	FCP
12.4	÷	*11.5*	×	*800*	=	*863* psi

q. Choke Line Friction (CLF)

SCP Choke Line	–	SCP Riser	=	CLF
n/a	–	*n/a*	=	*n/a*

Figure 4-10 Sample Problem

Graphical Analysis of Pumping Schedule



Pump Strokes	*0*	*100*	*200*	*300*	*400*	*500*	*600*	*700*	*800*	*900*	*1000*	*1100*	*1200*	*1300*	*1400*	*1500*	*1600*	*1700*	*1800*	*1900*	*2000*
Pressure	*1100*	*1079*	*1058*	*1037*	*1016*	*995*	*974*	*953*	*932*	*911*	*890*	*869*	*863*	*863*	*863*	*863*	*863*	*863*	*863*	*863*	*863*
Fluid Weight																					
Minutes																					

Figure 4-10 (continued)

WELL CONTROL KILL SHEET

BASIC DATA

a. True Vertical Depth (TVD)..... ______ ft.
b. Measured Depth (MD)........... ______ ft.
c. Fluid (Mud) Weight................ ______ lb_m/gal
d. Drillpipe Volume..................... ______ bbl
e. Riser Volume......................... ______ bbl
f. Pump Output.......................... ______ bbl/stk
g. Drillpipe Strokes..................... ______ stk
h. Strokes to Displace Rider...... ______ stk
i. Slow-Circulating Pressures (SCP)

Riser or Casing:

Pump #1: ______ psi @ ______ SPM
Pump #2: ______ psi @ ______ SPM

Choke Line (SUBSEA):

Pump #1: ______ psi @ ______ SPM
Pump #2: ______ psi @ ______ SPM

j. Maximum Allowable Casing Pressure

(Fracture Fluid Wt. – Present Fluid Wt.) × Casing Depth × 0.052

(_______ – _______) × _______ × 0.052 = _______ psi

KICK INFORMATION

k. Shut-In Pressure Drillpipe (SIDP)........................_______ psi
l. Shut-In Casing Pressure (SICP)..........................._______ psi
m. Kick Volume.._______ bbl

CALCULATE

n. Initial Circulating Pressure (ICP)

SCP + SIDP = ICP
_______ + _______ = _______

o. New Fluid (Mud) Weight (MW)

SIDP ÷ 0.052 ÷ Depth + Old MW = New MW
_______ ÷ 0.052 ÷ _______ + _______ = _______

p. Final Circulating Pressure (FCP)

New MW ÷ Old MW × SCP = FCP
_______ ÷ _______ × _______ = _______

q. Choke Line Friction (CLF)

SCP Chole Line – SCP Riser = CLF
_______ – _______ = _______

Figure 4-11 Well Control Kill Sheet

Graphical Analysis of Pumping Schedule

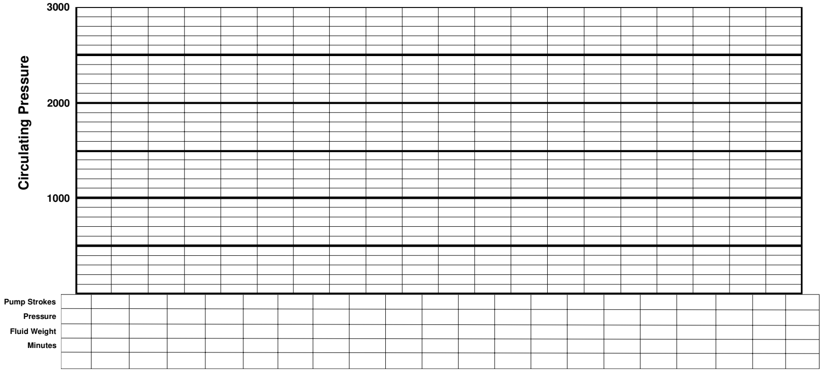


Figure 4-11 (continued)

Low Choke Pressure Method

This method is recommended for extreme kicks with pressures that threaten to exceed burst strength of casing or fracture gradient of exposed formations.

Essentially, this method limits maximum shut-in casing pressure to a predetermined level. Goins recommends a maximum of 80% of rated burst pressure of casing or hydrostatic pressure equivalent to 80% of casing depth in psi (50% for surface casing)[1]

When the well is shut-in, and a *predetermined maximum casing pressure is reached,* open the choke and begin circulating at approximately half of the normal circulating rate. Since casing and stand pipe pressures are not allowed to stabilize, fluid weight required to kill the well cannot be calculated.

As soon as circulation is initiated, begin increasing fluid density to the estimated level necessary to kill the well (not to exceed the estimated fracture gradient). After weighted fluid has been circulated partially up the annulus, another attempt can be made to shut the well in and observe pressures. If, at this point, casing pressure does not exceed the predetermined level, then stand pipe pressure can be measured and the correct fluid weight to kill the well can be calculated.

It should be pointed out that if this method is used, *a balanced condition is not maintained.* Formation fluids and/or gases will continue to flow into the wellbore until sufficient fluid, of increased density, is pumped into the annulus to overbalance formation pressures. It is conceivable that an excessive influx of formation fluid and/or gas could intrude into the well using this method. Therefore, this procedure should be applied with caution, particularly when dealing with severe kicks originating in highly permeable formations.

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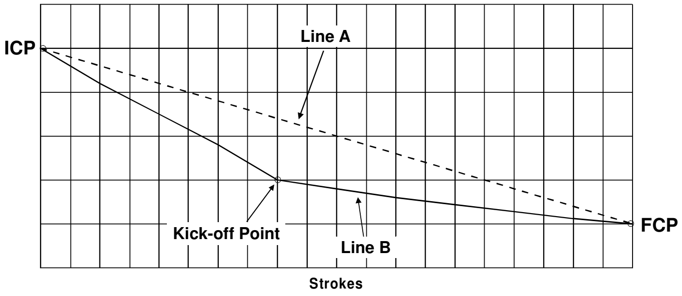
[1] W. C. Goins, Jr., "Guidelines for Blowout Prevention," *World Oil,* October 1968, pp. 91, 92.

Wait and Weight Procedure Corrected for Deviation[1]

Using a conventional wait and weight kill procedure on a highly-deviated well can overpressure the formation because the kill weight hydrostatic in the drillstring increases more rapidly down to the kick-off point than a conventional kill method accounts for. Figure 4-12 illustrates two pumping schedules as kill fluid travels to the bit, with Line A representing a conventional Wait and Weight schedule and Line B representing a schedule corrected for deviation.

Figure 4-12 Drillpipe Pressure Profile - Deviated Well



Line A = *Conventional Wait and Weight*

Line B = *Wait and Weight Corrected for Deviation*

The greatest difference in pressure occurs at the kick-off point. This pressure differential may or may not be significant, depending on weight-up increment, deviation, and depth. In the event of a kick in an highly-deviated well, Steps 1 through 22 below should be completed. If the pressure differential at kick-off (Step 22) exceeds a predetermined safety margin (usually 100 psi), then Steps 23 through 25 should be completed. A new pump pressure reduction schedule (graph or chart) should also be completed (Figure 4-13 and Figure 4-14). If the pressure differential is less than the safety margin (100 psi, for example) then a conventional kill sheet (Figure 4-11) may be used.

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[1] Source: Reading & Bates.

Well Kill Data for Deviated Well (English Units)

Well Information

1. True vertical depth (TVD) _______
2. Total measured depth (TMD) _______
3. Kick-off true vertical depth (KOTVD) _______
4. Kick-off measured depth (KOMD) _______
5. Drillstring capacity (DC) _______
6. Pump output (PO) _______
7. Fluid (mud) weight (OMW) _______
8. Slow-circulating pressure (SCP):
9. Pump #1:_______ psi at_______ SPM
10. Pump #2:_______ psi at _______ SPM
11. Shut-in drillpipe pressure (SIDP) _______
12. Shut-in casing pressure (SICP) _______
13. Kick volume (bbl) _______

Deviated Well Pressure Drop Calculations

14. Initial circulating pressure (ICP)
    - $ICP = SCP + SIDP$
15. New fluid (mud) weight (NMW)
    - $NMW = SIDP \div 0.052 \div TVD + OMW$
16. Final circulating pressure (FCP)
    - $FCP = NMW \div OMW \times SCP$
17. Surface to bit strokes (STB)
    - $STB = DC \times TMD \div PO$
18. Pressure drop per 100 strokes (PD_{TD})
    - $PD_{TD} = (ICP - FCP) \times 100 \div STB$
19. Surface to kick-off strokes (STKO)
    - $STKO = DC \times KO_{MD} \div PO$

20. Old method final circulating pressure at kick-off ($OFCP_{KO}$)
    - $OFCP_{KO} = ICP - (STKO \times PD_{TD} \div 100)$
21. Hydrostatic increase to kick-off (ΔH)
    - $\Delta H = (NWM - OMW) \times 0.052 \times KO_{TVD}$
22. Friction increase due to NMW at kick-off (ΔF)
    - $\Delta F = (FCP - SCP) \times KO_{MD} \div TMD$
23. New method final circulating pressure at kick-off ($NFCP_{KO}$)
    - $NFCP_{KO} = ICP + \Delta F - \Delta H$
24. Pressure difference at kick-off (ΔP_{KO})
    - $\Delta P_{KO} = OFCP_{KO} - NFCP_{KO}$
25. Pressure drop per 100 strokes to kick-off (PD_{KO})
    - $PD_{KO} = (ICP - NFCP_{KO}) \times 100 \div STKO$
26. Strokes from kick-off to TD (KOSTB)
    - $KOSTB = STB - STKO$
27. Pressure drop per 100 strokes, from kick-off to total depth
    - $PD_{KO} = (NFCP_{KO} - FCP) \times 100 \div KOSTB$

Pressure reduction schedules are shown in Figure 4-13 (completed example) and Figure 4-14 (blank form).

Figure 4-13 Deviated Well Pressure vs. Stroke Values - Example

PRESSURE Value of #21 minus value of #25 to value of #14	**STROKES** 0 to value #24 in 100 stroke increments	**PRESSURE** Value of #12 minus value of #23 to value of #21	**STROKES** 0 to value of #17 in 100 stroke increments
717	*0*	*1050*	*0*
711	*100*	*999*	*100*
705	*200*	*948*	*200*
699	*300*	*897*	*300*
693	*400*	*846*	*400*
687	*500*	*795*	*500*
681	*600*	*744*	*600*
675	*700*	*717*	*658*
668	*790*		

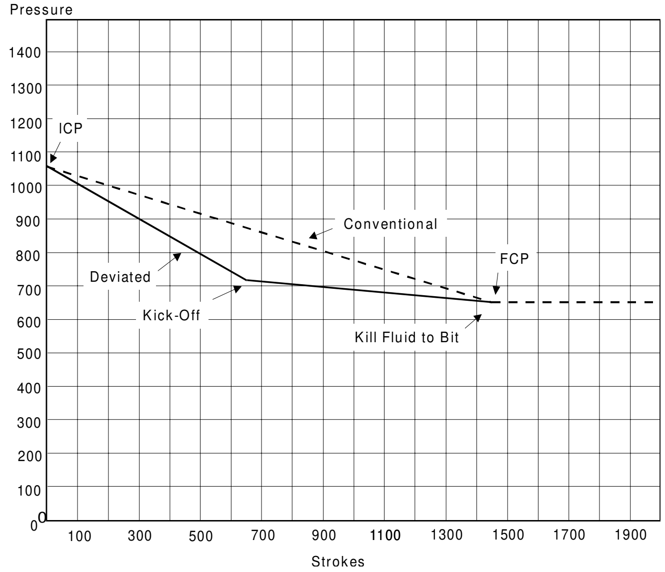
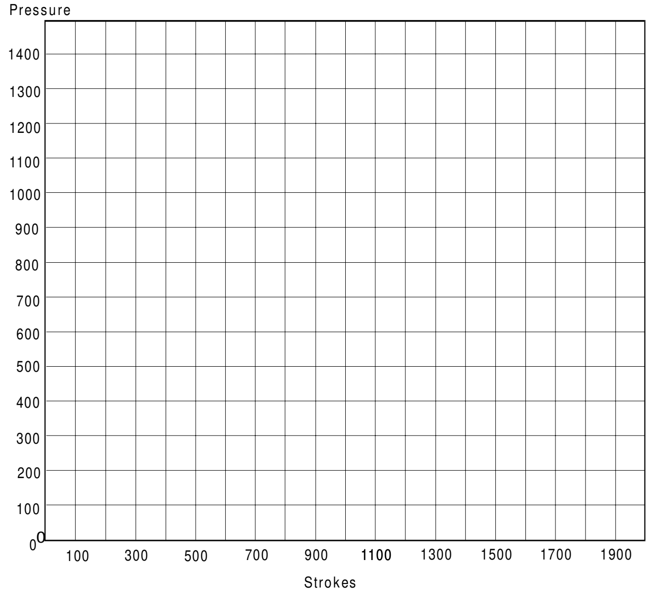


Figure 4-14 Deviated Well Pressure vs. Stroke Values - Blank Form

PRESSURE Value of #21 minus value of #25 to value of #14	**STROKES** 0 to value #24 in 100 stroke increments	**PRESSURE** Value of #12 minus value of #23 to value of #21	**STROKES** 0 to value of #17 in 100 stroke increments



Contingency Plans for Special Problems

Problem #1

Casing Pressures Threaten to Exceed Fracture Gradient with Only Conductor or Surface Pipe Set

In this case, lost circulation, an underground blowout, or a blowout around the casing could occur. Under these circumstances, it would be best to divert the flow from the well. Natural bridging often occurs and all that is required is to keep the hole filled with a fluid to decrease the chance of fire. Diverter systems should be built according to the specifications governing your particular area.

Note: *When sizing a diverter, it is important to prevent the build-upon back pressure. This can be accomplished by sizing the inside diameter of the diverter lines equal to the annular area feeding the diverter lines.*

Problem #2

Intermediate or Deep Surface Casing has Been Set, Casing Pressure Exceeds Fracture Gradient, and Loss of Circulation Occurs

Barite Plug (Function)

In the case of a gas kick, a barite plug would be in order. Barite plugs may seal the wellbore in four ways:

1. Due to low viscosities and yield points, barite may settle to form a solid plug in the hole.
2. Their high density increases the hydrostatic head on the active zone and helps control it.
3. Due to their high filter loss, they may dehydrate to form a solid plug of barite in the hole.
4. Their high filter loss may also cause the hole to slough and bridge. This is complemented by dehydration and/or settling of the barite plug.

Barite Plug (Formulation and Procedure)

A barite-water-phosphate slurry is usually mixed with cementing equipment, pumped through the drillpipe and spotted on bottom. The bit jets *do not* have to be removed.

---

1. Choose a slurry weight between 18 and 22 lb_m/gal.

Note: *The higher-density plugs have higher solids content, thus supporting themselves and settling slower. The settling time should be shorter for lower-density slurries.*

2. Determine how many feet of fill of barite in the open hole is desired (volume of open hole to be filled with barite). See Table 4-3.
3. Calculate the barrels of slurry and sacks of barite required, and add an extra 10 barrels. (For barite plugs in oil-base fluids, see Chapter 3, **Oil- and Synthetic-Base Drilling Fluids.**
4. Use freshwater to formulate the plug since barite does not settle as desired in seawater.
5. Treat the water with 0.5 lb_m/bbl of SAPP and adjust the pH to the 8 to 10 range with caustic soda. If TSPP is used, caustic is not required.

Note: *One quart of powdered SAPP (untamped) weighs 2.5* lb_m.

6. Mix the treated water with barite and simultaneously pump the slurry into the drillpipe.
7. Displace the slurry so that the height of the barite plug in the drillpipe is two (2) bbl higher than the top of the slurry in the annulus.
8. Break connections and pull up immediately above the plug. If possible, circulate on top of the plug.

Table 4-3 Barite Slurry Weight/Volume Relationships

Slurry Density (lb_m/gal)	Water (gal/bbl)	Barite (sack/bbl)	Slurry Volume/ Sack of Barite (bbl/sack)	Slurry Volume/ Sack of Barite (ft/sack)
18.0	26.9	5.30	0.189	1.060
19.0	25.3	5.94	0.168	0.945
20.0	23.7	6.43	0.156	0.873
21.0	22.2	6.95	0.144	0.807
22.0	20,6	7.50	0.133	0.748

Table 4-4 Mixing Procedure for Barite Plugs (Nonsettling) (1 bbl of 21 lb_m/gal Density)

1. Prepare mix water equal to 54% of final volume.		
2. Mix the following:		
Components	Water (fresh or sea)	0.54 bbl
	Lignosulfonate	15 lb_m
	Caustic soda	2 lb_m
	XANPLEX® D*	1 lb_m
	Defoamer	If needed
**For settling pill, omit XANPLEX D.*		
3. Add barite to mix water to prepare the final slurry. A 21 lb_m/gal slurry will require 700 lb_m of barite per finished bbl		

Common Equations Used in Well Control

1. Hydrostatic pressure

$$= 0.052 \times MW_1 \times TVD$$

2. Pressure expressed as equivalent fluid weight (EMW)

$$= \frac{P_S}{0.052 \times TVD} + MW_1$$

3. Fluid weight to balance a kick (MW_2)

$$= MW_1 + \frac{SIDP}{0.052 \times TVD}$$

4. Correction for change in system pressure loss (approximate) due to change in pump rate, while pumping out a kick (balanced pressure method):

$$P_a = P_b \times \left(\frac{R_2}{R_1}\right)^2$$

5. Determination of the nature of invading fluids:

$$W_f = MW_1 - \frac{SICP - SIDP}{0.052 \times L}$$

Note: *If W_f is 8.5 to 10.0, the invading fluid is saltwater. If W_f is ≤ 2.0, the invading fluid is gas. If W_f is 2.0 to 8.5, the invading fluid is a mixture of gas and water or oil.*

6. Approximate maximum casing pressure resulting from a gas kick: (see **Note** in Step 7 below)

$$P_{csg}\ \max = 200 \sqrt{\frac{(P)\ (V)\ (MW_2)}{C}}$$

7. Approximate maximum amount of volume increase while circulating out a kick:

$$V\ \text{gain max} = 4 \sqrt{\frac{(P)\ (V)\ (C)}{MW_2}}$$

Note: *Due to the solubility of gas in oil, these formulas (7 and 8) **will not hold true** when using an oil- or synthetic-base fluid.*

8. Formation pressure or bottomhole pressure:

$$BHP = (MW_1 \times 0.052 \times TVD) + SIDP$$

9. Maximum initial shut-in casing pressure which will equal fracture gradient:

$$SICP_{max} = (F_{mw} - MW_1)0.052 \times TVD_s$$

10. Boyle's Law (assumes temperature and compressibility are constant):

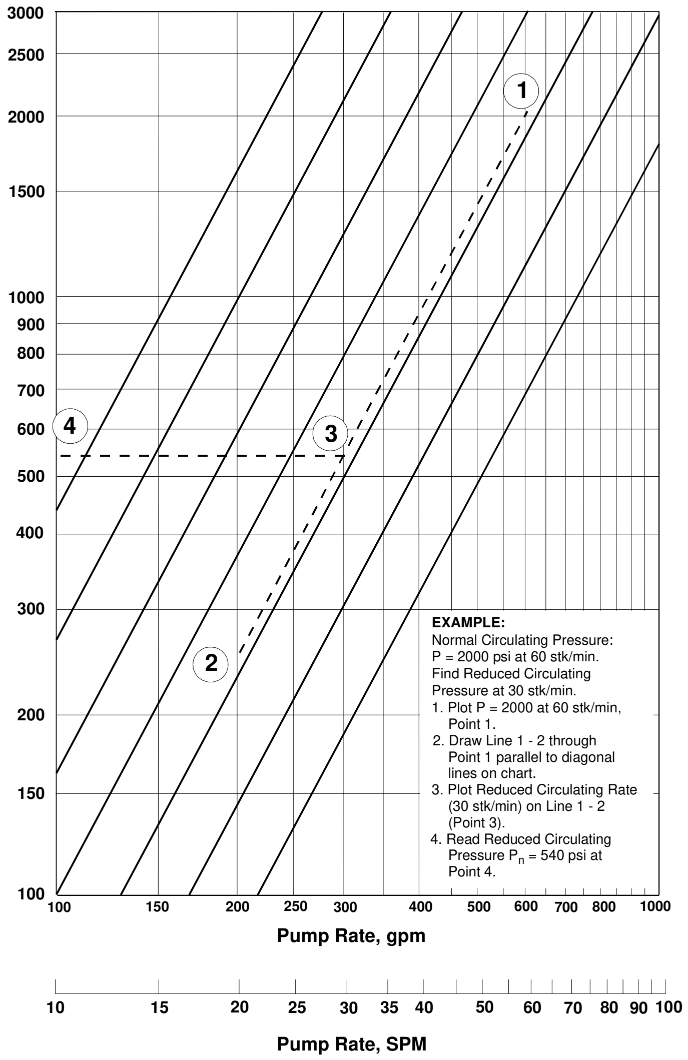
$$P_1V_1 = P_2V_2$$

Note: *From Boyle's Law, it is apparent that gas must be allowed to expand as it comes up the hole; otherwise, surface pressures will be nearly equivalent to bottomhole pressures and lost circulation will probably occur.*

Nomenclature

C	Annular capacity at the surface, bbl/l000 ft
EMW	Equivalent fluid (mud) weight, lb_m/gal
F_{mw}	The fluid density required to initiate a fracture in a formation, lb_m/gal
FCP	Final circulating pressure, psi
ICP	Initial circulating pressure, psi
L	Length of the column of invading fluids in the annulus, ft
MW_1	Initial fluid weight or fluid weight in hole, lb_m/gal
MW_2	Required or maximum anticipated fluid weight, lb_m/gal
psi/ft	Pressure gradient of a column of fluid (units)
P	Formation pressure, psi
P_a	New system pressure loss at new pump rate, psi
P_b	Original system pressure loss at old pump rate, psi
P_{csg}	Approximate maximum casing pressure, psi
P_s	Surface pressure imposed on a fluid column, psi
P_1	Pressure of gas at the zone of intrusion, psi
P_2	Pressure of gas at the surface, psi
R_1	Original pump rate, at which P_b occurred
R_2	New pump rate for which P_a must be calculated
SICP	Shut-in casing pressure, psi
SIDP	Shut-in drillpipe pressure, psi
TVD	True vertical depth, ft
TVD_s	True vertical depth of casing shoe, ft
V	Pit gain, bbl
V_1	Volume of gas at the zone of intrusion, bbl
V_2	Volume of gas at the surface, bbl
W_f	Density of fluids invading wellbore, lb_m/gal

Figure 4-15 Determination of Reduced Circulating Pressure



EXAMPLE:
Normal Circulating Pressure:
P = 2000 psi at 60 stk/min.
Find Reduced Circulating Pressure at 30 stk/min.

1. Plot P = 2000 at 60 stk/min, Point 1.
2. Draw Line 1 - 2 through Point 1 parallel to diagonal lines on chart.
3. Plot Reduced Circulating Rate (30 stk/min) on Line 1 - 2 (Point 3).
4. Read Reduced Circulating Pressure P_n = 540 psi at Point 4.

Solids Control

Drilled Solids

One of the primary functions of a drilling fluid is to carry drilled solids from the well bore. These solids are a contaminant and, if left in the system, can lead to numerous operational problems. There are three ways to control the build up of drilled solids to maintain acceptable drilling fluid properties.

1. Let the solids build up. Throw the fluid away when it has lost its utility and start with fresh fluid.
2. Dilute the solids and rebuild the system to keep the fluid properties within an acceptable range. Dispose of any excess fluid.
3. Remove the drilled solids to reduce the amount of dilution necessary to maintain acceptable fluid properties.

The benefits of removing excessive drilled cuttings from the fluid include the following.

- Reduced fluid treatment costs
- Reduced torque and drag
- Increased penetration rates
- Reduced system pressure losses, resulting in lower equivalent circulating density (ECD) and fewer instances of lost circulation
- Lower water requirements
- Better cement jobs
- Less differential sticking
- Less waste, resulting in reduced environmental impact and lower disposal costs
- Reduced formation damage

Effect of Drilled Solids on Fluid Properties

As undesirable solids accumulate in the fluid, changes in the fluid properties will be noted. Depending upon the size and shape of the solids, fluid loss may either increase or decrease. In general, the quality of the filter cake will deteriorate (i.e., become thicker and softer). The most immediate changes will be noted in the fluid's rheological properties.

Plastic viscosity is largely due to mechanical friction between solid particles in the drilling fluid. Plastic viscosity depends primarily on the size, shape, and number of solids in the fluid. Progressive increases in plastic viscosity can indicate a build up of drilled solids.

Yield point and *Gel strength* indicate the degree of attractive forces between particles in the fluid. These attractive forces are related to the distance between the particles. When yield values and gel strengths become excessive, treatment with a dispersant or deflocculant is usually indicated. As the concentration of solids increase, these treatments become less and less effective. At some point, continued treatments will result in an *increase* in the fluid's overall rheological properties.

The quantity of solids required to reach this level depends upon the size of the solids. Lower concentrations of fine solids can be tolerated. Conversely, the removal of very fine particles from the fluid produces a greater reduction in viscosity than does the removal of an equivalent volume of coarser solids due to the difference in surface area.

When chemical treatments for solids contamination are no longer effective, the solids must be either diluted to an acceptable level or removed by mechanical means. The most prudent course of action is to remove the solids before a treatment problem occurs. This is the job of the rig's solids control equipment.

Particle Classification

Solids in drilling fluids may be classified in two separate categories based on specific gravity (or density) and particle size.

Specific Gravity

Solids, classified by specific gravity (S.G.), may be divided into two groups.

1. High density solids, S.G. > 4.2 (weight materials)
2. Low density solids, S.G. from 1.6 to 2.9, (average of about 2.6). These include sand, clays, shales, dolomite, calcium carbonate and many fluid treatment materials. See Table 4-5.

In fluid containing only high gravity or low gravity solids, the fluid density is a function of the concentration of the solids. Fluids containing both will have a total solids content varying between the high and low gravity concentrations needed to achieve a particular density. Since some low gravity solids are used in most drilling fluid preparations and more are incorporated by drilling, this will always be the case in a normal drilling fluid. Figure 4-16 shows the solids content of typical fresh water drilling fluids. The shaded range represents the total solids content that produces *acceptable* fluid properties.

Figure 4-16 Average Solids Range of Water-Base Drilling Fluids (Freshwater)

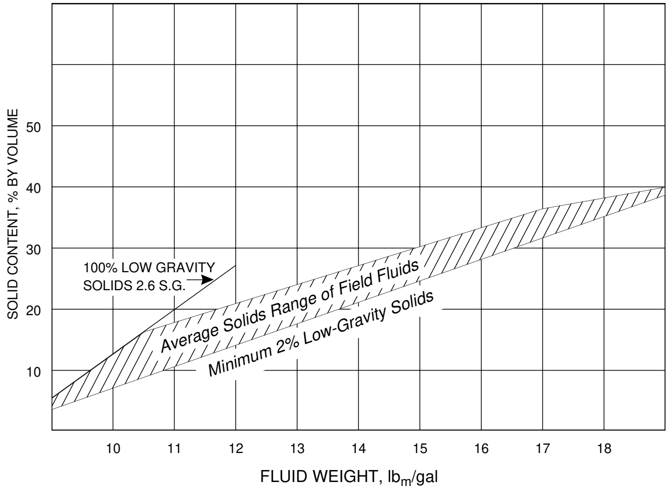


Table 4-5 Density of Common Oil Field Materials

Hematite	5.0
Barite	4.0 - 4.5
Bentonite	2.3 - 2.7
Limestone	2.7 - 2.9
Diesel Oil	0.85
ISO-TEQ™	0.792
Water (fresh)	1.0
Sand	2.6 - 2.7

Particle Size

Solids are classified according to size and are measured in units called microns (μ). A micron is $^{1}/_{25,400}$ of an inch or $^{1}/_{1000}$ of a mm. Particle size is important in drilling fluid for the following reasons.

1. The smaller the particle size the more pronounced the affect on fluid properties.
2. The smaller the particle the more difficult it is to remove or control its effects on the fluid. Colloidal size particles (Table 4-6) dramatically affect fluid properties.

It is extremely important to remove as many particles as possible in the first circulation. The larger particles will degrade into finer particles as they react with the drilling fluid and are circulated through the system.

Particle Size (microns)	Particle Classification	Sieve Size
Greater than 2000	Coarse	10
2000 - 250	Intermediate	60
250 - 74	Medium	200
74 - 44	Fine	325
44 - 2	Ultra fine	—
2 - 0	Colloidal	—

Table 4-6 API Classification by Particle Size

Mechanical Solids-Control Equipment

The mechanical removal of drilled solids utilizes three techniques: (1) screening, (2) centrifugal force, and (3) combinations of the first two. Screening is the only technique that makes a separation based upon physical particle size. Equipment that makes use of centrifugal force separates solids based upon differences in relative mass. Settling is not considered as a mechanical removal technique, although it is a useful method for solids control.

Proper *set up* and *sequence* of mechanical control equipment is essential to a successful solids removal program. Failure of an upstream unit can result in overloading and decreasing efficiency of downstream equipment. Proper sequencing includes returning the desired fraction of the processed fluid to the next downstream pit and corresponding piece of equipment. When this is not done, the ability of the equipment to remove its designed size of solids is greatly reduced.

Figure 4-17 through Figure 4-20 show the proper arrangement of equipment for common drilling situations. Note that the figures also indicate the positioning of the weirs between the compartments.

API Recommended Practice 13C contains additional guidelines for installing, operating and maintaining the solids control system and its individual pieces of equipment.

Figure 4-17 Unweighted Fluid: Centrifuge Processing Active System

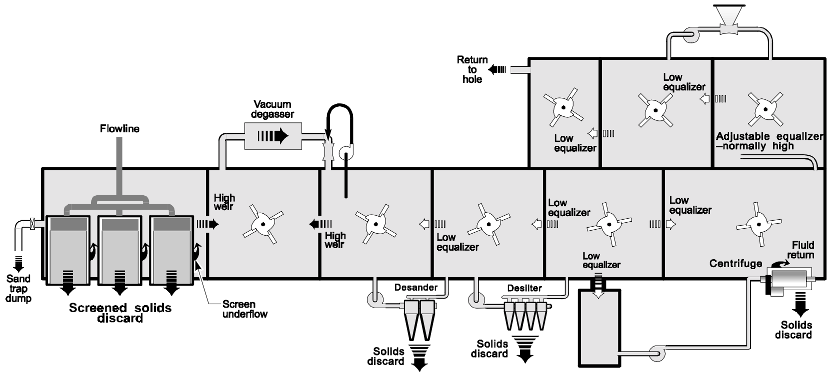


Figure 4-18 Unweighted Fluid: Centrifuge Processing Hydrocyclone Underflow

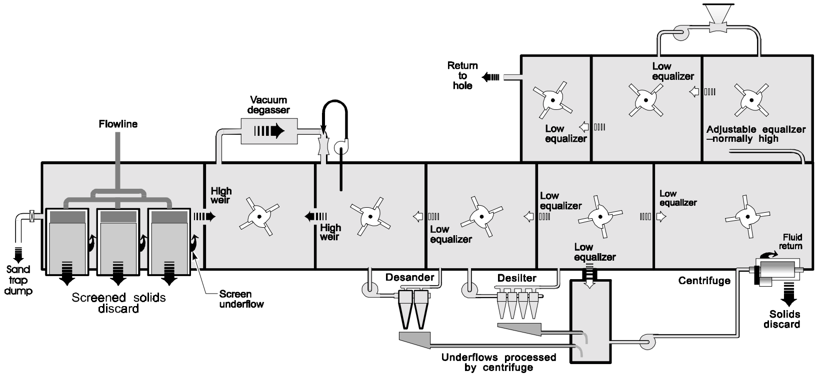


Figure 4-19 Weighted Water-Base Fluid: Single-Stage Centrifuging (Barite Recovery)

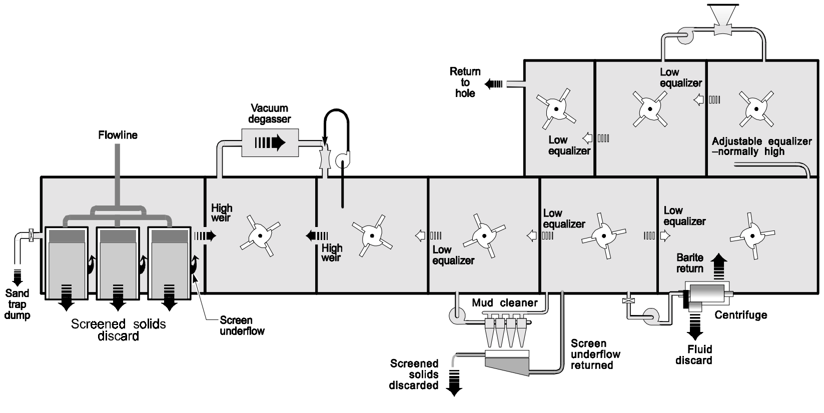
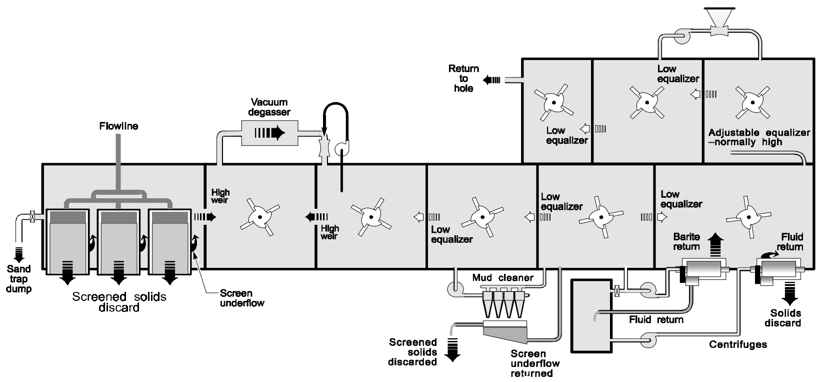


Figure 4-20 Weighted Fluid: Two-Stage Centrifuging



Screen Devices (Shale Shakers)

Shale shakers are the first line of defense in the solids removal system. They have proven to be a simple and reliable method of removing large amounts of coarse cuttings from the drilling fluid. In unweighted fluids, the shaker's role is to reduce the solids loading on the downstream equipment. In weighted fluids, it is the primary solids removal device and is used to remove all drilled cuttings coarser than the weighting material. It is primarily for this latter purpose that fine screen, linear motion shale shakers were developed.

Screening area sufficient to process the entire circulating rate should be used. The amount of screening area required and shaker performance are related to:

- Drilling fluid rheology
- Solids loading rate (penetration rate, hole diameter, and flow rate)
- Deck size and configuration
- Screen characteristics
- Vibration pattern and dynamics

Shakers can be classified by the pattern made by the basket over a vibration cycle. Three vibration patterns are commercially available.

- Circular
- Unbalanced elliptical
- Linear

Circular and unbalanced elliptical machines are recommended primarily for gumbo or soft, sticky solids conditions and as scalping shakers for coarse solids removal. Linear motion machines are used in all applications where fine screening is required. Cascading arrangements are used to reduce the solids loading on fine screened machines.

Screens

Shaker screen selection is the largest, single factor affecting the overall performance of the shale shaker. Understanding the factors that impact screen performance can aide in the selection of screens. Screen performance is measured by:

1. Separation performance (size of the solids removed)
2. Liquid throughput (amount of fluid transmitted)
3. Service life

Because shaker screens are manufactured in a number of configurations, there is considerable confusion about the performance characteristics of each type of screen. In order to provide a common ground for comparing the separation characteristics of different screens, the API has established a tagging procedure for screens.

The tag affixed to the screens contains three pieces of information.

1. The manufacturer’s designation
2. The screen’s separation potential, expressed as d_{50}, d_{16}, and d_{84} “Cutt” points

Note: *The term “Cutt” (pronounced “koot”) point is used to differentiate separation potential from the traditional particle size cut points normally associated with separation devices. The process used to determine “Cutt” points was developed at Amoco Exploration and Production Technology. It is a much faster and easier method to determine the separation potential of a screen and has been found to correlate well with the grade efficiency developed from standard measurement techniques.*

3. The screen’s flow capacity, determined from its conductance and total non-blanked area.

Note: *The conductance and non-blanked area of the screen are reported on the tag. The engineer can determine the screen’s flow capacity by multiplying the conductance by the non-blanked area, or the individual numbers can be compared by inspection to determine which screen has a greater flow capacity. Conductance is normally reported in kiloDarcies per millimeter. Open area is normally reported in square feet.*

API RP 13E contains a detailed discussion on the procedures used to determine the values reported on the tag. The values are valid for most standard open-weave screens. Polyester and coated screens cannot be compared to standard screens

using these techniques. Typical nomenclature for three screen manufacturers is listed below.

Brandt-Drexel – EPI (formerly SWECO)

Screen Panels in General

- BLS – Brandt, layered screen with plastic strip
- BXL – Brandt, extra life
- S – Square mesh, market-grade screens
- B – Rectangular mesh.

The designation will be followed by a number. In the case of the BLS, BXL, and S, this will be the mesh. For the B designation, most likely it is the sum of the mesh in both directions.

Example

B120 – Rectangular mesh with 80 wires in one direction and 40 in the other.

Designations

- LMP – linear shaker, market-grade cloth, perforated panel backing,
- LTP – linear shaker, tensil bolting cloth, perforated panel backing.

First numeric character designates the perforated panel opening size; the next three, equivalent mesh size.

Example

- LMP2200 – for linear shaker, market-grade cloth, perforated panel, 2 in. openings, 200-mesh.

Cagle

General-Type Designations

- HCS – High-Capacity Square mesh screens
- HCR – High-Capacity Rectangular mesh screens

The number after the letter indicates the approximate U.S. Standard Sieve equivalent. HCR screens are high aspect ratio screens patented by Cagle. These screens have higher throughput at comparable separation potential than standard weave screens. They also are reported to have a service life that is four to five times longer than comparable standard screens.

Derrick Manufacturing

Screen Panels in General

- SWG – indicates three-layer screen, non-repairable
- PWP – 3 screen layers bonded to a perforated metal plate that adds support and repairability
- GBG – 2-layer bonded screen panels
- PMD – Patented Pyramid® three-dimensional screen surface mounted on a perforated plate. The corrugated design adds 40% more screen area over a PWP screen with a 70% increase in fluid handling capability.
- PMD+ – Same as PMD but with higher peaks giving 100% more screen area compared to a PWP screen.

Specific Screen Specifications

- DX – Derrick extra fine
- DF – Derrick fine
- DC – Derrick coarse
- MK – Market grade
- HP – High performance (rectangular mesh).

Note: *The panel designation is followed by 2 numbers that give the screen panel size in inches. The screen specification is followed by a number that indicates the equivalent mesh size of the screen.*

Example

GBG 48-30 HP 200 – bonded high-performance, screen, 48×30 inches, 200-mesh equivalent.

Centrifugal Devices

Solids removal by centrifugal devices depends upon particle separation by mass. The centrifugal separator mechanically subjects the fluid to increased “gravitational (G) forces” thus, increasing the settling rate of the particles. This method separates the fluid solids into heavy-coarse and light-fine fractions. The desired fraction is then selected and returned to the system. This technique works well with low-density/low-solids and high-density fluids and is the basis of most solids-control programs. It should be remembered that with any centrifugal separating device, the D-50 point (the point at which a solid of a given size has a 50/50 chance of removal by underflow or overflow) is affected by the total solids content, fluid weight, and fluid viscosity.

Desanders

Common oil fields desanders are 12" to 6" I.D. hydrocyclones. They process fluid from immediately below the sand trap, not from the sand trap. A typical desanding set up consists of enough cones to process 125% to 150% of the flowline gpm.

Desilters

Most desilters currently in use consist of banks of 4" I.D. hydrocyclones. This equipment processes fluid from below the desander. Enough cones are used to process 150% of the circulating rate.

Desander/Desilter Operation Tips

1. Most hydrocyclones are designed to operate at a manifold pressure equivalent to about 75 feet of head (35 to 45 psi). Head is related to pressure and fluid density by the hydrostatic pressure equation

   $$P = 0.052 \times H \times \rho_{mud}$$

   where

   P = feed pressure (psi),
   H = head (ft),
   ρ_{mud} = fluid density (lb/gal).

   Excessive pressure contributes to bladder wear and detrimentally affects cut point.

2. Proper discharge from the cones is a conical spray. Cone discharge may be adjusted by turning the adjustment at the cone apex. Roping may occur when the fluid to be processed has an excessive amount of solids present in the fluid.

3. Cones may become plugged. They can be cleaned by opening the adjustment and inserting a welding rod or equivalent from the bottom to dislodge the solids blocking the discharge. Continual plugging of cones may be due to the failure of upstream solids control equipment, which should be checked to ensure functionality.

Fluid (Mud) Cleaners

The hydrocyclone/screen combination consists of a bank of desilters which are mounted over a fine mesh vibrating screen (140- to 200-mesh). The desilter underflow is processed by the fine screen. Particles removed by the screen are discarded and the fluid processed through the screen is returned to the active system. The effluent or desilter overflow is also returned to the active system. The fluid cleaner is essentially a fine screen shaker. Its primary purpose is to remove that portion of sand-sized or larger particles that pass through the rig shaker. Ideally, a 200-mesh screen would be desirable on the fluid cleaner, however, a 140- to 150-mesh screen is generally necessary to minimize barite losses.

Fluid cleaners are not recommended on low-weight systems that can utilize a desilter, because the desilter will remove more fine solids. On the other hand, on unweighted systems with very expensive liquid phases, the fluid (oil-base fluids, polymer-KCl fluids, etc.) lost at the desilter under flow will be costly. In these cases, a fluid cleaner can aid in the control of drilled solids.

The fluid cleaner is not a centrifuge and does not replace a centrifuge on weighted systems. However, this device does fill a gap if premium shakers are not employed with a weighted drilling fluid. Rig shakers may only be able to use an 80-mesh screen which removes drilled solids larger than 178 microns. The centrifuge removes drilled solids smaller than 4 to 6 microns, so it is apparent that a particle that passes through the 80-mesh screen will be retained in the system until it is ground down to the 4- to 6-micron range. Utilizing a fluid cleaner with 200-mesh screens would give a 74-micron cut.

Removal of particles in the 74- to 178-micron range with the fluid cleaner can produce the following benefits.

1. Improved filter cake quality (less coarse drilled solids) results in a less-permeable, less-porous cake. Improved cake quality (thinner and tougher) can minimize wall sticking and reduce frictional forces between drillstring and wellbore.
2. A decreased concentration of drilled solids contributes to improved rheological properties and reduced fluid maintenance costs.

Centrifuges

The decanting centrifuge is used to recover barite and remove fine solids from the drilling fluid. It is a common misconception that centrifuges separate low-gravity solids from barite. The solids removed with a centrifuge are the very fine (below 4.5 to 6 microns) particles which have a greater effect on rheology than the coarser particles. Since the machine makes a separation based upon the mass of the particle, no discrimination between *high-gravity* and *low-gravity* particles can be made.

Centrifuging will not, however, eliminate the need for water. Dilution rates will be reduced and a fluid maintenance cost reduction can be expected. Day to day trends in plastic viscosity can give an indication of how fast solids concentration is increasing and can be used as a guide for centrifugation or dilution. The Methylene Blue Test (MBT) analysis and solids content can also be of assistance in this determination.

The decanting centrifuge uses a rotating bowl to create high centrifugal force to effect the separation of coarse and fine particles. A conveyor screw rotates at a slightly slower speed to move the coarse solids to the underflow port.

There are basically three types of decanting centrifuges. The types are grouped depending on the “G” force, rpm, cut point, and feed capacity.

1. ***Barite recovery centrifuge*** – Used primarily for viscosity control. These centrifuges operate in an rpm range of 1600 to 1800 rpm and generate a “G” force from 500 to 700 “G”s. Cut point will be between 6 to 10 microns for low-gravity solids and 4 to 7 microns for high-gravity solids. Feed rates normally run from 10 to 40 gpm depending on the density of the whole fluid. This centrifuge will strip barite above the cut point from the fluid and discard the liquid phase with the remaining fine solids.
2. ***High-volume centrifuge*** – Used primarily for discarding low-gravity solids from the fluid. It is so named because processing rates range from 100 to 200 gpm. Normal rpm range is from 1900 to 2200 rpm. “G” forces average about 800 “G”s. The cut point attained is from 5 to 7 microns on unweighted fluid applications.

3. ***High-speed centrifuge*** – Used for removal of low-gravity solids from unweighted fluid systems and as second centrifuge in dual-centrifuging applications. This group of centrifuges turn from 2500 to 3300 rpm. “G” forces created by these units range from 1200 to 2100 “G”s. Cut point can be as low as 2 to 5 microns. Feed rates will range from 40 to 120 gpm depending on application and the fluid to be processed.

The term *dual centrifuging* comes from the use of two centrifuges in tandem. Effluent from a barite recovery unit is used to feed the second centrifuge. The benefit of this operation is that fine solids can be removed without the loss of the fluid phase.

The principle of the decanting centrifuge is illustrated in Figure 4-21.

Suggested Guidelines

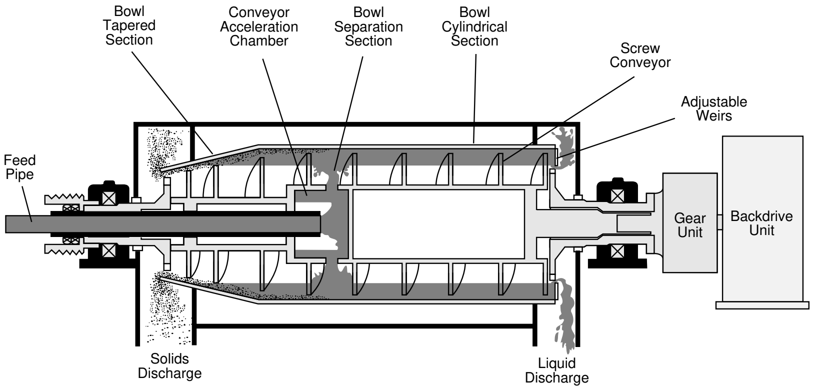
Suggested guidelines for operation of decanting centrifuges:

- Effluent viscosity – 35 to 37 sec/qt
- Effluent density – 9.5 to 9.6 lb_m/gal

(May be greater if excessive quantities of barite are near colloidal.)

- Underflow density – usually 23 to 23.5 lb_m/gal
- Bowl speed – 1600 to 2000 rpm
- Dilution 25% to 75%. The dilution rate increases as viscosity and density increase.
- The centrifuge should be sized to process a minimum of 10% of the maximum anticipated flow rate.
- Percentage of low-gravity solids removed – normally 30% to 60%
- Chemical removal. Underflow of decanting centrifuge will contain 15% to 30% of chemicals present in original drilling fluid.
- Volume decrease is 70% to 85% of fluid centrifuged. Depends on volume of solids in the recoverable range.

Figure 4-21 Solid Bowl Decanting Centrifuge



Closed-Loop Systems

Closed-loop systems describe any operation where no reserve pit is utilized. This is commonly due to environmental restrictions, but may be caused by space limitations, cost to build and close the pit, or expense of the liquid phase. Depending on the economics of disposing of excess fluid and cuttings, the system may consist of no additional equipment on the rig to a full-blown system that includes all the mechanical equipment necessary to achieve maximum solids removal and a dewatering operation to finish the removal of all excess solids.

The term *closed-loop* system, when only mechanical equipment is employed to remove the solids, is more often than not a misnomer. There is a limit on how long the fluid system can go before it has to be displaced because of fine solids build up. Currently available solids control equipment cannot remove solids that are in the colloidal-size range.

The addition of a dewatering system to the solids processing will allow the system to more closely reflect the name *closed-loop system*. This is achieved by removing the solids that remain in any recovered fluid. Figure 4-22 and Figure 4-23 depict the arrangement of mechanical solids removal equipment on a closed-loop system for unweighted and weighted fluid systems respectively.

The dewatering system operates by destabilizing the fluid chemically, causing coagulation of the solids, and then chemically *flocculating* the solids. “Flocced” solids and liquid are then separated by use of a centrifuge or screwpress to achieve maximum concentration of the solids in the discard and maximum return of the solids-free liquid to the fluid system.

The benefits of utilizing a dewatering system vary depending on the fluid type. Besides the primary benefit of reduced waste disposal, reduction in fluid maintenance can be realized for two reasons.

1. The amount of solids carried can be controlled without total dependence on chemical thinners.
2. Any soluble materials in the liquid phase will be returned to the system after the flocculation process.

This will reduce the cost of fluid built to replace that lost with the solids.

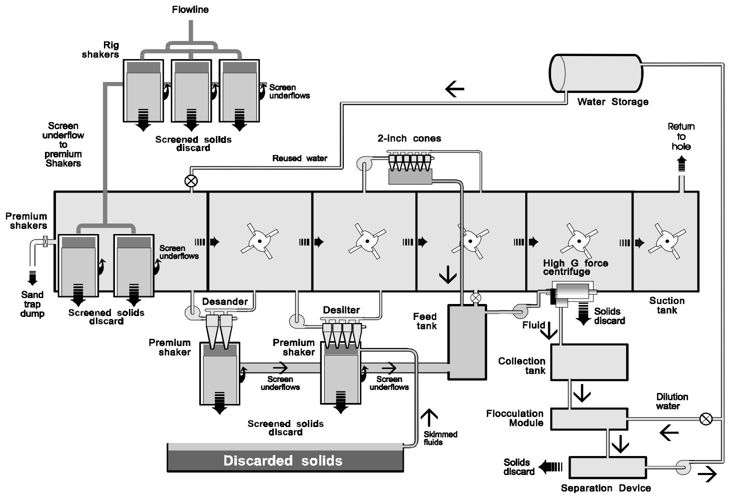


Figure 4-22 Closed Loop Solids System: Unweighted Fluid

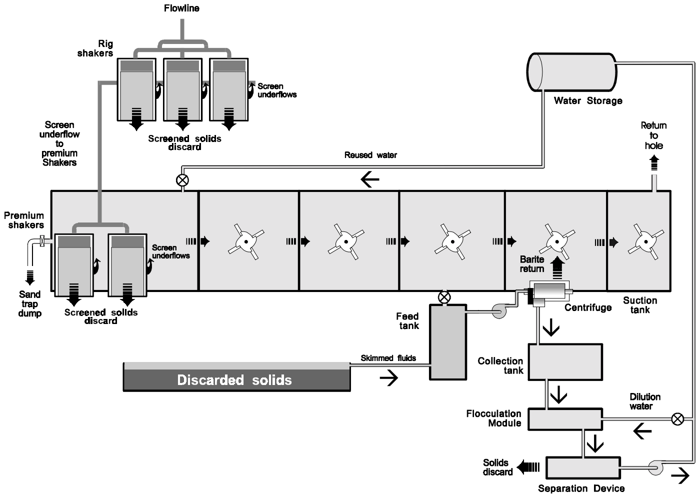


Figure 4-23 Closed Loop Solids System: Weighted Fluid

Solids Analysis

Drilling Fluid Water, Oil, and Solids

It is the function of the solids control equipment to remove as large a fraction of the drilled solids from the fluid as “practical”. In this case, “practical” assumes the connotation of “cost efficient”. Since no process in 100% efficient, the accumulation of drilled solids into the drilling fluid is inevitable. It is the responsibility of the engineer to determine what level of drilled solids can be tolerated in the fluid and to establish the most “practical” method for dealing with the remainder.

The analysis of the solids content of the fluid is a tool used by the engineer to monitor the accumulation of solids in the drilling fluid. API RP 13B-1 contains the procedure for measuring the total water, oil, and solids content of the fluid from the retort data. It then provides calculations for establishing the concentrations of low and high gravity solids present in the fluid. An abbreviated form of this procedure is reproduced below. This procedure applies only to water-base fluids. A procedure for oil- and synthetic-base fluids is contained in API RP 13B-2 and Chapter 3 of this manual.

API Solids Analysis

Using the measured volumes of oil and water from the retort and the volume of the original whole fluid sample (10-cm^3 or 20-cm^3), calculate the volume percent water, oil, and total solids in the fluid.

Volume Percent Water

$$V_W = \frac{100(\text{volume of water, cm}^3)}{\text{volume of sample, cm}^3}$$

Volume Percent Oil

$$V_O = \frac{100(\text{volume of oil, cm}^3)}{\text{volume of sample, cm}^3}$$

Volume Percent Retort Solids

$$V_S = 100 - (V_W + V_O)$$

Additional calculations are required to find the volume percent suspended solids and relate them to the relative volumes of low gravity solids and weighting material. To make these calculations, accurate fluid weight and chloride concentration are needed.

$$V_{SS} = V_S - V_W\left(\frac{C_S}{1{,}680{,}000 - 1.21\,C_S}\right)$$

where

V_{SS} = volume percent suspended solids,

C_S = chloride concentration (mg/L).

Volume Percent Low Gravity Solids

$$V_{lg} = \frac{1}{\rho_b - \rho_{lg}}[100\rho_f + (\rho_b - \rho_f)V_{SS} - 12W_m - (\rho_f - \rho_o)V_O]$$

where

V_{lg} = volume percent low gravity solids,

W_m = fluid weight (lb/gal),

ρ_f = density of filtrate (g/cm^3),

($\rho_f = 1 + 0.00000109\ C_S$ based on sodium chloride)

ρ_b = density of weighting material, g/cm3 (use 4.2 if barite, 5.0 if hematite),

ρ_{lg} = density of low gravity solids, g/cm^3 (use 2.6 if unknown),

ρ_O = density of oil, g/cm^3 (use 0.84 if unknown).

Volume Percent Weighting Material

$V_b = V_{SS} - V_{lg}$

Concentration of Low Gravity Solids, Weighting Material, and Suspended Solids

$C_{lg} = 3.50(\rho_{lg})(V_{lg})$

$C_b = 3.50(\rho_b)\ (V_b)$

$C_{SS} = C_{lg} + C_b$

where

C_{lg} = low gravity solids concentration, lb/bbl,

C_b = weighting material concentration, lb/bbl,

C_{SS} = suspended solids concentration, lb/bbl.

Bentonite Correction

The methylene blue test (MBT) reading is a measure of the concentration of bentonite and reactive clays in the fluid. To determine the actual concentration of bentonite in the fluid, use the following equations.

$$\mathrm{CEC}_{avg} = \frac{(7.69)(\mathrm{MBT}_{fluid})}{(\mathrm{V}_{lg})}$$

$$\mathrm{V}_{bent} = \frac{(\mathrm{V}_{lg})(\mathrm{CEC}_{avg} - \mathrm{CEC}_{DS})}{(\mathrm{CEC}_{bent} - \mathrm{CEC}_{DS})}$$

$$V_{DS} = V_{lg} - V_{bent}$$

where

CEC_{avg} = avg CEC of all low-gravity solids in the fluid,

V_{bent} = volume percent bentonite in the fluid,

V_{lg} = volume percent low-gravity solids in the fluid,

V_{DS} = volume percent drill solids in the fluid,

MBT_{fluid} = methylene blue test on the fluid (lb$_m$/bbl),

CEC_{DS} = cation exchange capacity of the cuttings,

CEC_{bent} = cation exchange capacity of the bentonite (use 60 if unknown).

Given

$\mathrm{V}_{lg} = 9.8$,

$\mathrm{CEC}_{DS} = 10$,

$\mathrm{MBT}_{fluid} = 30$,

$\mathrm{CEC}_{bent} = 60$,

then

$$CEC_{avg} = \frac{(7.69)(30)}{(9.8)} = 23.5,$$

$$V_{bent} = \frac{(9.8)(23.5 - 10)}{(60 - 10)} = 2.65,$$

$$V_{DS} = 9.8 - 2.65 = 7.15.$$

Solids Removal System Performance

Another tool that is used by the engineer to assess the effectiveness of the solids control program is an evaluation of the efficiency of the system to remove drilled solids. The efficiency of the drilled solids removal system (a.k.a., solids control equipment) has been generally reported as the percentage of the drilled rock that was removed by the equipment. This does not take into account the amount of fluid lost in the process. By this definition, jetting the fluid would give 100% removal efficiency, but would not be a practical method due to the amount of drilling fluid lost. Thus, to more accurately describe the performance of a system, a term is needed that will take into account both the percentage of rock removed and the amount of drilling fluid lost.

The *Dilution Factor* is used to describe the Drilled Solids Removal System Performance. The Drilled Solids Removal System is defined as all processes used while drilling a well that remove the solids generated. These processes consist of dumping of whole fluid (including lost circulation), settling, screening, desanding, desilting, and centrifuging.

The Dilution Factor is calculated by monitoring the total amount of base fluid (oil or water) added to the system and recording the density, salinity, and retort data collected over a specified drilling interval. The data is averaged and the dilution factor calculated based upon the hole size and interval length. A drilled solids system performance index is calculated and used as a base for monitoring system performance. The procedure below is abstracted from Section 1 of API RP 13C.

1. Measure and record all suction pit fluid weight, salinity and solids (retort) data for the interval.

2. Measure and record base fluid additions to the system (V_{bf}).
3. Determine the *Base Fluid Fraction* (F_{bf}). The Base Fluid Fraction is calculated from retort data and salt measurements and is the average value for the interval. The averaging method is critical. It is important to use the same method if comparisons between intervals and wells are to be made.
4. Calculate the *Volume of Fluid (Mud) Built* (V_{mb}). The volume of fluid built is determined from the Base Fluid Fraction. $V_{mb} = V_{bf} / F_{bf}$
5. Determine the *Drilled Solids Fraction* (F_{ds}). The Drilled Solids Fraction is calculated by averaging the drilled solids values calculated from retort measurements taken at various points in the interval. 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.
6. Calculate the excavated *Volume of Solids Drilled* (V_{ds}). The value is calculated from the dimensions of the wellbore, i.e., length and diameter.
7. Calculate the *Total Dilution* (D_t). Total Dilution is defined as the volume of fluid that would be built if there were no solids removal system. In this case, all drilled solids would be incorporated into the fluid system and dilution is the only form of solids control. Total Dilution = $D_t = V_{ds} / F_{ds}$
8. Calculate the *Dilution Factor* (DF). The Dilution Factor is the ratio of the Volume of Fluid Built to Total Dilution. It is the ratio of fluid used to drill an interval using a solids removal system compared to dilution only. The lower the factor, the more efficient the solids removal system is. Dilution Factor = $DF = V_{mb} / D_t$
9. Calculate the *Drilled Solids Removal System Performance* (SP). $SP = (1 – DF)(100)$

Directional Drilling

Applications for Horizontal Drilling

Since horizontal wells are more expensive to drill than vertical wells, increased production must offset increased drilling costs. The following are currently the most popular applications for horizontal drilling.

- Naturally fractured reservoirs
- Formations with water or gas coning problems
- Thin pay zones
- Low-permeability reservoirs
- Irregular formations (reefs, channel sands, etc.)
- Low-energy drive reservoirs
- Enhanced oil recovery

Drilling Fluid Selection

Virtually all of the considerations for choosing a fluid for drilling a vertical hole apply to choosing a fluid for a directional hole. These are the principle factors that require extra consideration in drilling highly-deviated holes.

- Formation protection
- Hole cleaning
- Lubricity
- Inhibition
- Fluid weight required
- Economics
- Environmental impact

An additional consideration is the effect of the installation of the positive displacement motor and associated MWD tools on the hydraulic performance of the circulating system. For a given set of surface equipment, these additional system pressure losses may severely limit the maximum achievable fluid flow rate. Since fluid flow rate affects both the performance of the motor (and thus drilling rate) and the hole cleaning ability of the fluid, these pressure losses must

be considered in the hydraulic evaluation of the circulating system. The **NaviDrill Motor Specifications** table enumerates the flowrate range required for each tool.

Figure 4-24 gives graphical representations of pressure drops for various INTEQ MWD tool configurations and fluid weights. The pressure drop across the fluid motor will vary with drilling conditions and tool wear. It is normally in the range of 300 to 500 psi, with high-torque, low-speed motors having higher pressure drops than low-torque, high -speed motors. The motor pressure drop is normally measured on location by comparing the circulating pressure with the tool off bottom to that with the tool on bottom and operating at the desired speed and weight on bit. The data are available from the directional driller.

A final consideration is the interaction of the drilling fluid and its components with the elastomers used in the motor. Some fluid additives, e.g. certain corrosion inhibitors and lubricants, and all oil-base fluids with aniline points less than 150°F. may shorten elastomer life and result in motor failure or reduced performance.

INTEQ Technical Alert #96/17/LS is a compilation of trade name products and fluid systems that have been tested in the laboratory for their compatibility with the elastomers used in the NaviDrill motors. The products are rated as **1**, **2**, or **3**. A **1** rating indicates that the product or system has the least affect on the elastomer; a **3** rating has the most affect on the elastomer. The list is considered to be “company confidential” and can be accessed through ***InSource***.

Note: *If the effect of a fluid or additive on a motor’s elastomer is not known, it should be evaluated before the fluid or additive is used.*

NaviDrill Motor Specifications

Motor Type	Flow Rate (gpm)	Bit Speed (rpm)	Torque (ft-lbs)	HP Output	Stages (number)	Rotor/Stator Configuration	RPM Ratio (rpm/gpm)
3-1/8" M1ADM	80 - 160	63 - 126	710	16	2	5/6	0.79
3-1/8" M1X	80 - 160	182 - 365	380	27	3	5/6	2.28
3-1/8" M1XL	80 - 160	182 - 365	720	50	6	5/6	2.28
3-3/4" M1C	65 - 185	120 - 340	890	58	5.5	5/6	1.84
3-3/4" M1XS	80 - 210	150 - 410	440	34	3	5/6	1.95
3-3/4" M1XL	80 - 210	150 - 410	1620	126	11	5/6	1.95
3-3/4" M2	65 - 210	250 - 800	480	73	5	1/2	3.81
4-3/4" M1ADM	160 - 320	55 - 110	1620	34	2	5/6	0.34
4-3/4" M1P/HF	160 - 320	105 - 210	1700	68	4	5/6	0.66
4-3/4" M1P/HF (short)	160 - 320	105 - 210	1105	45	2.5	5/6	0.66
4-3/4" M1X	105 - 315	110 - 325	1360	84	5	5/6	1.03
4-3/4" M1XL	105 - 315	110 - 325	2600	161	9.5	5/6	1.03
4-3/4" M1C	80 - 240	100 - 300	1180	67	5.5	5/6	1.25
4-3/4" M1C-DPS	80 - 240	100 - 300	2360	100	11	5/6	1.25
4-3/4" M2PXL	80 - 265	180 - 600	1440	164	11	2/3	2.26
4-3/4" M2	80 - 265	195 - 650	740	92	5	1/2	2.45
6-3/4" M1ADM	345 - 610	53 - 94	4280	76	2	7/8	0.15
6-3/4" M1P/HF	345 - 610	100 - 180	4800	165	4	7/8	0.30
6-3/4" M1X	265 - 660	90 - 220	2690	113	3	5/6	0.33

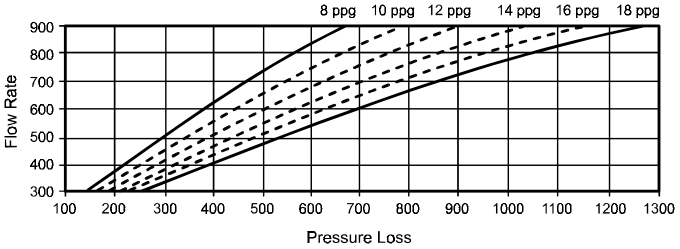
NaviDrill Motor Specifications (continued)

Motor Type	Flow Rate (gpm)	Bit Speed (rpm)	Torque (ft-lbs)	HP Output	Stages (number)	Rotor/Stator Configuration	RPM Ratio (rpm/gpm)
6-3/4" M1XL	265 - 660	90 - 220	5050	212	6	5/6	0.33
6-3/4" M1P	265 - 485	110 - 200	4300	164	5	7/8	0.41
6-3/4" M1C	185 - 475	100 - 260	2800	139	5	5/6	0.55
6-3/4" M2	185 - 530	190 - 550	1840	193	5	1/2	1.04
8" M1ADM	530 - 900	48 - 81	7450	115	2	7/8	0.09
8" M1P/HF	530 - 900	90 - 150	8500	243	4	9/10	0.17
8" M1X (Dec)	395 - 900	85 - 195	4500	168		5/6	0.22
8" M1XL (Dec)	395 - 900	85 - 195	7800	290	6	5/6	0.22
8" M1P	395 - 660	90 - 150	7750	181	5	7/8	0.23
8" M1C	315 - 685	85 - 190	4500	163	4	5/6	0.28
8" M2	240 - 685	155 - 450	2400	206	4	1/2	0.66
9-1/2" M1P/HF	660 - 1110	80 - 130	12500	310	4	9/10	0.12
9-1/2" M1P	475 - 795	80 - 130	11060	273	5	7/8	0.16
9-1/2" M1XL	530 - 1060	80 - 165	10770	338	6	5/6	0.16
9-1/2" M1C	395 - 740	100 - 190	6870	249	5.5	5/6	0.26
11-1/4" M1P	795 - 1270	70 - 110	17700	370		9/10	0.086

Figure 4-24 Closed Loop Solids System: Weighted Fluid

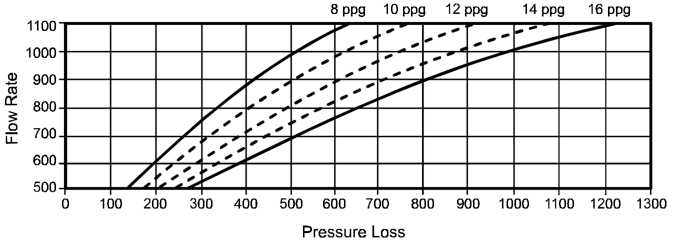
7-3/4 - 9-1/2" Tools, Normal Flow Ranges

4xMiller, VG = 0.91"



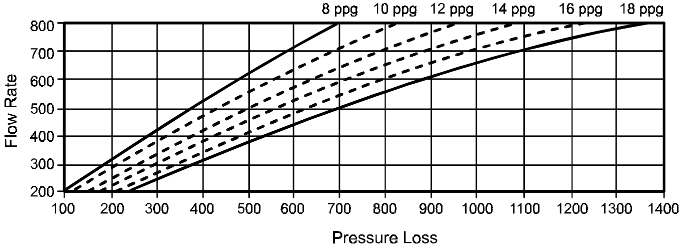
7-3/4 - 9-1/2" Tools, High Flow Range (520-1050)

4xMiller, VG = 0.97"

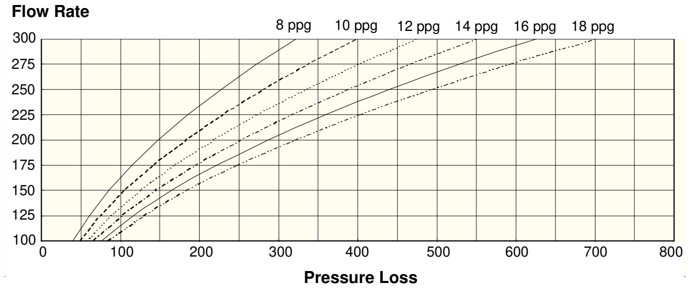


6-3/4" Tools, All Flow Ranges

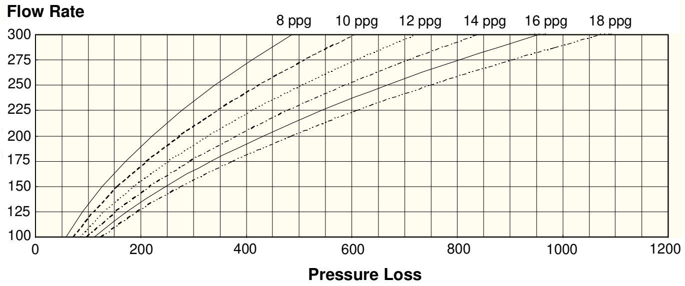
4xMiller, VG = 0.87"



Probe Based Tools, R 1/2
Collar ID = 2-3/4", n = 0.40, K = 13.2



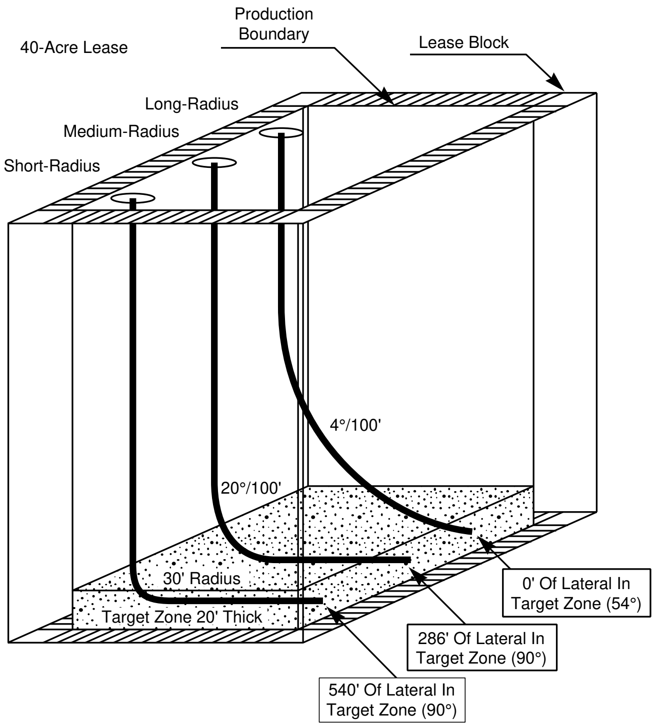
Probe Based Tools, R 1/4
Collar ID = 2-3/4", n = 0.40, K = 13.2



Directional Techniques

Technique	Build-Up Rate	Turning Radius
Long Radius	1° to 6°/100 ft	1000' to 3000'
Medium Radius	6° to 40°/100 ft	140' to 1000'
Intermediate Radius	40° to 70°/100 ft	82' to 140'
Short Radius	70° to 150°/100 ft	40' to 82'
Ultra-short radius uses a jetting mandrel to turn in a matter of inches. Conversions: ft ÷ 3.28 = m; °/100 ft ÷ 3.048 = °/10 m		

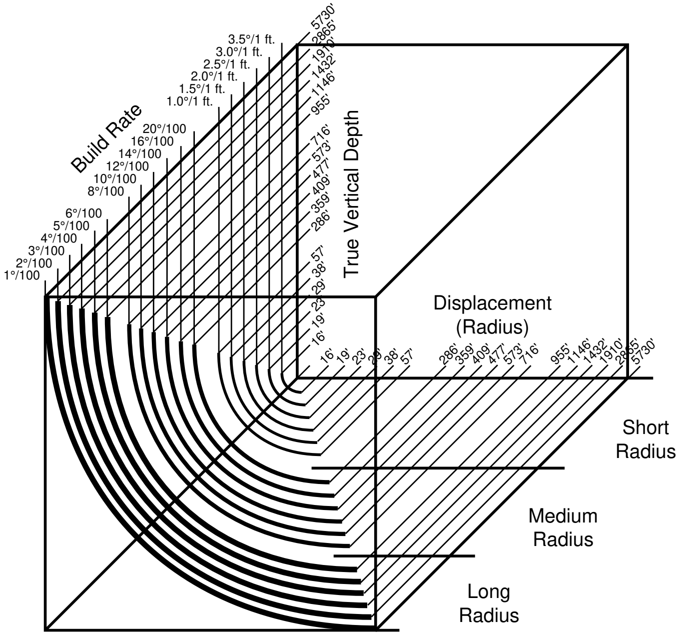
Figure 4-25 Directional Techniques



Deviation and Loss of Depth per 100 ft of Measured Depth

Deviation (degrees)	Deviation (ft)	Loss of Depth (ft)	Vertical Depth (ft)
1	1.75	0.02	99.98
2	3.49	0.06	99.94
3	5.23	0.14	99.86
4	6.98	0.24	99.76
5	8.92	0.38	99.62
6	10.45	0.55	99.45
7	12.19	0.75	99.25
8	13.92	0.97	99.03
9	15.64	1.23	98.77
10	17.36	1.52	98.48
12	20.79	2.19	97.81
14	24.19	2.97	97.03
16	27.56	3.87	96.13
18	30.90	4.89	95.11
20	34.20	6.03	93.97
25	42.26	9.37	90.63
30	50.00	13.40	86.60
35	57.36	18.08	81.92
40	64.28	23.40	76.60
45	70.71	29.29	70.71
60	86.60	50.00	50.00

Figure 4-26 Build-up Curves



Cleaning Highly-Deviated Holes

As hole inclination increases, axial particle slip shifts to radial particle slip, causing cuttings to fall to the low side of the borehole. Cuttings transport becomes more difficult and often results in the formation of a cuttings bed. In general:

1. Fluid annular velocity is a key parameter in cuttings transport. If an hole-cleaning problem exists, cuttings transport may be improved by increasing flow rate to its maximum value with flow regime and pump limitations.

2. In laminar flow, higher yield point/plastic viscosity (YP/PV) ratios improve cuttings transport; when in turbulent flow, fluid rheology has little effect on cuttings transport. This appears to be true in all ranges of inclination.
3. Pipe eccentricity makes cuttings transport more difficult as fluid velocity is reduced in the more narrow portions of the annulus.
4. When annular fluid is laminar, thin, turbulent sweeps followed by thick sweeps may aid hole cleaning by first stirring the cuttings, then sweeping them out of the hole.
5. Hydraulic hole cleaning may be supplemented by mechanical means. Wiper trips and drillstring rotation (when possible) disturb the cuttings bed and encourage transport. Top drives are beneficial by allowing pipe rotation and circulation while tripping.

Ranges of Inclination

Hole inclination, with regard to hole cleaning, has been categorized into three general ranges. The following ranges and characteristics were described by Okrajni, et al. in SPE Paper l4l78.

0° to 45°	Laminar flow with higher YP/PV ratios yields best cuttings transport. Cuttings bed can begin to form on lower side of the borehole.
45° to 55°	Laminar and turbulent flow have similar transport results. Higher YP/PV ratio aids hole cleaning when in laminar flow; fluid rheology has little effect on cuttings transport when in turbulent flow. Cuttings bed may slide downhole.
55° to 90°	Turbulent flow provides better cuttings transport; higher YP/PV ratio improves transport in laminar flow. Cuttings beds generally will not slide downhole.

Note: *Competency of the formations drilled should always be considered when selecting the flow regime.*

Torque and Drag

In an highly-deviated wellbore, there is considerable contact between the drillstring and the borehole wall, generating frictional resistance to movement. This resistance can be large enough to be the limiting factor in horizontal and extended-reach drilling. Since there are many factors that affect torque and drag, it is sometimes difficult to detect what is causing increased downhole friction. Figure 4-27 is a flow chart designed to help determine the possible cause associated with torque and drag symptoms.

Friction reduction can be achieved by using a drilling fluid with good lubricating qualities such as oil-base fluids, polymer fluids, and glycol-derivative systems. There are also a large number of lubricant additives available; these should be tested for fluid and formation compatibility as some can have detrimental effects. In general, lubricants may be of a mechanical nature (beads, nut plug, etc.), general borehole or film lubricants, or extreme-pressure (metal-to-metal) lubricants.

Regardless of the system or lubricant used, downhole friction can be reduced by conditioning the fluid to achieve a thin, slick, compressible filter cake, and by practicing good hole-cleaning techniques to minimize the cuttings bed.

Hole Stability

Boreholes fail through either compressive or tensile failure. Wellbores fracture when borehole pressures exceed the tensile strength of the surrounding rock. When wellbore pressures are too low, the compressive strength of the surrounding rock may be exceeded and borehole collapse may occur. Drilling fluids can weaken the surrounding rock, causing borehole failure to become more likely. Rock competency should be preserved by using proper filtrate control, inhibiting ions, bridging agents, and flow regime.

Hole inclination can effectively reduce the safe operating wellbore pressure range by requiring a higher minimum fluid weight to prevent collapse and a lower maximum fluid weight to prevent fracture. An example of the calculated borehole safe operating range for a North Sea sandstone as calculated by McLean, et al., is shown in Figure 4-28.

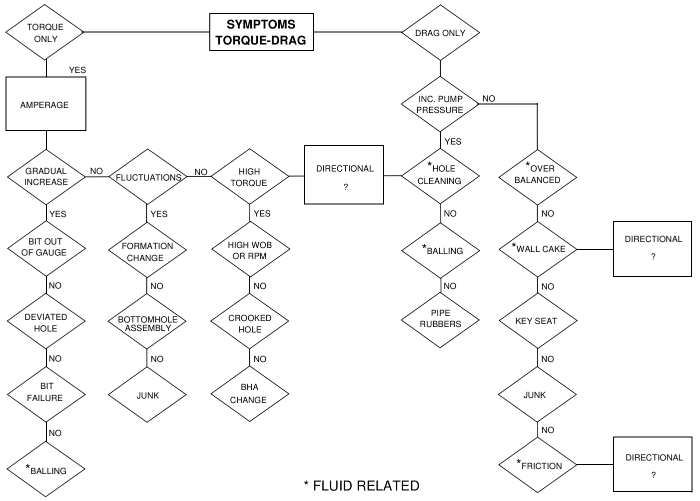
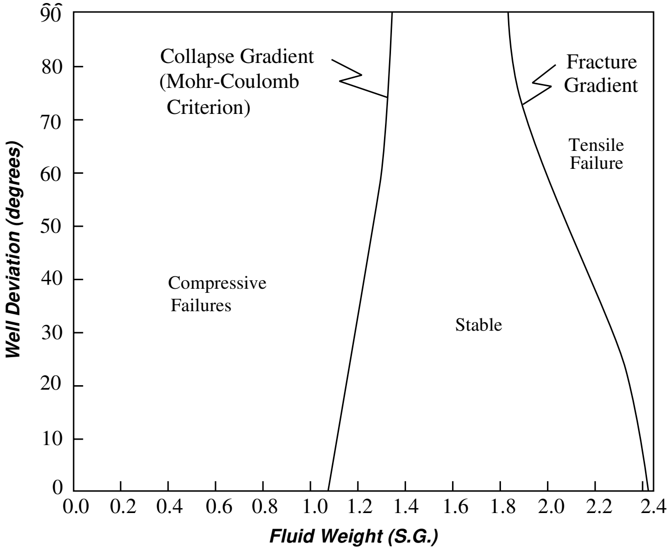


Figure 4-27 Wellbore Problems

Figure 4-28 Example of the Effect of Deviation on Borehole Stability for a North Sea Sandstone



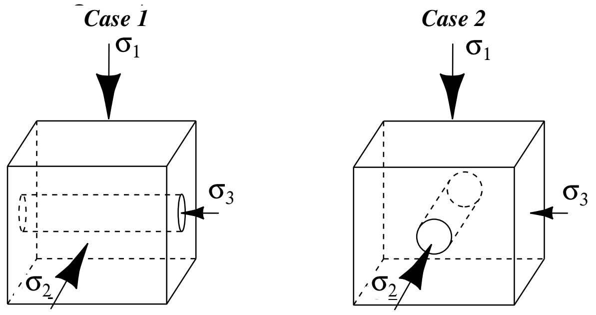
Source: SPE Paper 20405

In a tectonically-stressed area, the geographical direction of the borehole can also affect borehole stability. Boreholes inclined in the direction of the least principle in-situ stress tend to be more stable than those inclined in the direction of the maximum principle in-situ stress.

As illustrated in Figure 4-29, when all other factors are equal, Case 1 will produce a more stable hole than Case 2.

As a result, wells of different inclination and direction may not correlate directly with regard to fluid weight and hole stability.

Figure 4-29 Borehole Alignment in Tectonically-Stressed Areas



Where: σ_1 = Maximum Principle In-Situ Stress

σ_2 = Intermediate Principle In-Situ Stress

σ_3 = Minimum Principle In-Situ Stress

Formation Protection

Since horizontal wells expose considerably more of the prospective producing zone, care should be taken to choose a drilling fluid that will minimize formation damage. Fluid compatibility can be tested by checking the return permeability of reservoir core samples when exposed to various fluids. Some of the principle causes of formation damage are listed below.

Causes of Formation Damage

- Fluid solids blocking pore throats
- Hydration of formation clays
- Migration of formation fine solids
- Wettability changes in the reservoir
- Insoluble precipitants
- Water blocking
- Emulsion blockage

Calculations

1. True vertical depth (average angle method):

$$TVD_2 = TVD_1 + \left[(MD_2 - MD_1) \times \cos\left(\frac{\Theta_1 + \Theta_2}{2}\right)\right]$$

2. Horizontal displacement (average angle method):

$$HD_2 = HD_1 + \left[(MD_2 - MD_1) \times \sin\left(\frac{\Theta_1 + \Theta_2}{2}\right)\right]$$

3. Kick-off point determination:

$$\text{KOP, ft} = T - \left[\frac{5720}{BUR} \times (\sin\Theta_2 - \sin\Theta_1)\right]$$

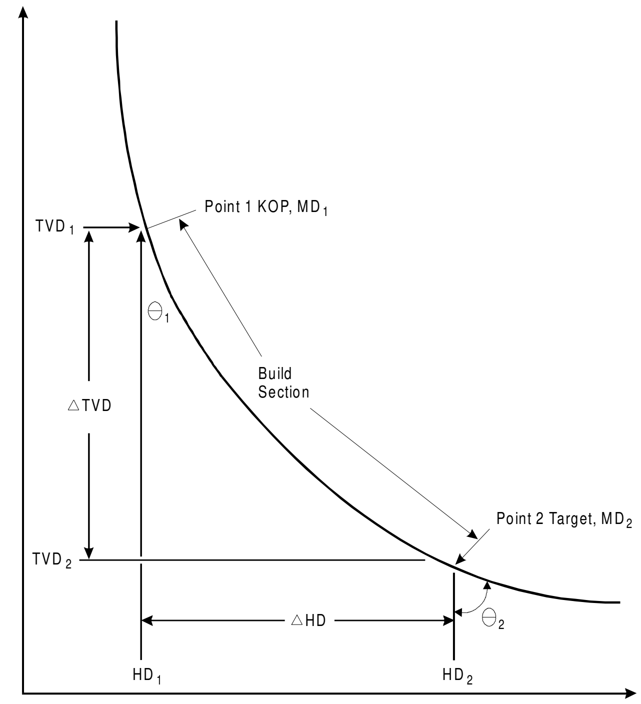
where

TVD_1 = true vertical depth at point 1,
TVD_2 = true vertical depth at point 2,
MD_1 = measured depth at point 1,
MD_2 = measured depth at point 2,
HD_1 = horizontal displacement at point 1,
HD_2 = horizontal displacement at point 2,
Θ_1 = deviation at point 1,
Θ_2 = deviation at point 2,
T = target depth (ft.),
BUR = build-up rate (°/1 ft.).

Note: *This method assumes that the course length between point 1 and point 2 is a straight line. The direction and inclination are also assumed to be the averages of the values measured at each point. The method will be less accurate when applied over long course lengths, but is a good approximation for most drilling fluid engineering calculations.*

Note: *Calculations for deviated wells should use measured depth when calculating volumes and vertical depth when calculating equivalent fluid weights.*

Figure 4-30 Well Profile for Calculations, Average Angle Method



Corrosion

Introduction

Corrosion is the destruction of a metal by chemical or electrochemical reaction with its environment. By any standard of measure, corrosion is a severe and costly problem in the drilling industry. Because the tubular goods are mostly iron and most fluids are water-base, corrosion is inevitable. Four conditions must be met, however, before wet corrosion can occur.

1. Anode and cathode must exist.
2. The anode and cathode must be immersed in an electrolytic medium.
3. A potential difference between anode and cathode exists.
4. There must be a coupling to complete the electrical circuit.

The anode and cathode exist on the drillpipe itself. The drilling fluid can serve as the electrolytic medium, and the coupling is created by the drillpipe steel. The potential difference is created by the crystalline structure and different metals used in the drilling pipe alloy, or as a result of scale formation.

Factors Affecting Corrosion Rate

Several factors affect the rate at which corrosion proceeds. Most of these factors are interrelated and have a synergistic effect on the corrosion rate. The basic relationships are as follows.

Temperature

Two different effects occur.

1. As temperature increases, the corrosion rate increases. If all other factors remain constant, the corrosion rate doubles for each 55°F (31°C) increase in temperature.
2. Increasing temperature decreases the solubility of corrosive gases (O_2, CO_2, H_2S), thus decreasing the corrosivity of the fluid. Note that “solubility” here refers to the solubility of gas at surface pressure, and does not include chemical reactions of gases such as CO_2 and H_2S with the fluid.

Pressure

Increasing pressure increases the solubility of most corrosive gases. Entrained or trapped air rapidly goes into solution in the fluid as the pressure increases when the fluid is pumped downhole. This dramatically affects the oxygen content of the fluid which increases corrosivity.

pH

Generally, corrosion rate decreases as pH increases. At ambient temperatures, as the pH increases, corrosion rates rapidly decrease. Rates are much slower in alkaline fluids than in acidic fluids. Little reduction in corrosion rate is obtained as pH is increased above 10.5.

Dissolved Salts

The effect of salt concentration is twofold.

1. As salt concentration increases, conductivity rises, thus increasing corrosion rate.
2. Increasing salt concentration, however, reduces oxygen solubility and decreases corrosion rate. The overall effect is a brief rise in corrosion rate due to conductivity until the salt concentration reaches approximately 18,000 mg/L (Cl^-). Above this range, as salt concentration increases, oxygen solubility and corrosion rate decrease.

Corrosive Agents and Treatments

Oxygen (O_2)

1. Source – The atmosphere.
2. Reactions – Oxygen corrosion of iron (Fe) is termed a cathodic depolarization reaction. Basically, where water and oxygen are present, this is what happens:
    - $Fe \rightarrow Fe^{+2} + 2e^-$ (Oxidation/anodic reaction)
    - $O_2 + 2H_2O + 4e^- \rightarrow 4OH^-$ (Reduction/cathodic reaction)
    - $2Fe + 2H_2O + O_2 \rightarrow 2Fe^{+2} + 4OH^- \rightarrow 2Fe(OH)_2$
    - $2Fe(OH)_2 + H_2O + \frac{1}{2}O_2 \rightarrow 2Fe(OH)_3$

    The final product is the loose, flaky deposit called rust, which has the reddish-brown color of iron hydroxide, $Fe(OH)_3$.

3. Type Attack – Pitting, localized (deep pits), or general (evenly distributed shallow pits).
4. Treating Agents:
   - NOXYGEN™ – Ammonium bisulfite (NH_4) HSO_3
   - AMI-TEC™ – Film-forming amine (see CO_2 Treating Methods)
5. Treating Methods – Inject NOXYGEN via chemical pump into the pump suction. Adjust injection rates to maintain the sulfite residual 75 to 125 mg/L sulfite residual (at flowline). Where filtrate calcium levels are untreatable or excess lime is present, maintain only an indication of sulfite residual.

Carbon Dioxide (CO_2)

1. Source – Formations and bacterial degradation of fluid additives.
2. Reactions:
   - $CO_2 + H_2O \rightarrow H_2CO_3$ (Carbonic acid)
   - $H_2CO_3 \rightarrow H^+ + HCO_3^- \rightarrow 2H^+ + CO_3^=$
   - $2H^+ + Fe \rightarrow Fe^{2+} + H_2\uparrow$
   - $Fe^{2+} + CO_3^= \rightarrow FeCO_3\downarrow$
3. Type Attack – Severe pitting (worm-eaten appearance).
4. Treating Agents:
   - Caustic Soda – NaOH
   - Lime – $Ca(OH)_2$
   - AMI-TEC – Film-forming amine
   - SCALE-BAN™ – Scale inhibitor
5. Treating Methods – Where the intrusion of CO_2 is not severe, neutralization with caustic soda and lime or gypsum by maintaining a pH of 10.0 or higher may be the easiest, most cost-effective method. If lime or gypsum is used, SCALE-BAN™ should also be used to inhibit the deposition of calcium carbonate scale on the drillpipe. Scale will encourage the development of oxygen corrosion cells and pitting. Consequently, eliminating scale and reducing oxygen levels with NOXYGEN™ will reduce corrosion.

Where a CO_2 influx has become severe, or where neutralization requires large treatments, several steps may be necessary to minimize the corrosive effect on the drillstring.

- Where possible, raise fluid weight to stop the influx.
- MIL-TEMP® or ALL-TEMP ™treatments can be extremely effective at controlling rheological properties which will minimize the entrapment of CO_2 and O_2. MIL-TEMP or ALL-TEMP will also minimize the flocculating effects of lime additions which are essential to precipitate carbonates and balance alkalinities.
- Use AMI-TEC™ to form a protective film on the drillstring. AMI-TEC can be used with solids-laden fluids. Treatment is accomplished by pumping a 25 to 35 gal “batch” down the drillpipe on a regular basis. A batch is prepared by mixing AMI-TEC and diesel oil in a 1:5 to 1:20 ratio depending on the level of protection required. The batch size (number of gallons) depends on the length of the pipe to be coated and the annular diameter. (See **Corrosion Treatment Tips**.)
- In order to effectively maintain an inhibitive film with amines, tourly treatments are recommended.

Note: *Entrainment of excessive amounts of amines into drilling fluids may result in flocculation of the system, therefore avoid overtreatment.*

- Continue to treat with caustic soda and lime to neutralize the acid gas. In addition, treat the system with SCALE-BAN to prevent scale deposition. Treatment with SCALE-BAN™ is 3 to 5 gal per 1000 bbl initially, and 1 to 2 gal each day thereafter.
- Testing Procedures – Monitor alkalinities and pH periodically to ensure that carbonates are precipitated and solubility of carbon dioxide is minimized. The Garrett Gas Train for carbonates is necessary to properly monitor the fluid system quantitatively.

Hydrogen Sulfide (H_2S)

WARNING!!!
Hydrogen sulfide (H_2S) is *highly poisonous* as well as *corrosive*. Small concentrations in air *may be fatal in minutes* (see Table 4-7). When H_2S is expected, be thoroughly familiar with protective measures in advance.

1. Source – Formations are the primary source with bacterial and thermal degradation of fluid additives contributing minor amounts.
2. Reaction:
   - $H_2S + H_2O \rightarrow H^+ + HS^- \rightarrow 2H^+ + S^=$
   - $2H^+ + Fe \rightarrow Fe^{2+} + H_2\uparrow$
   - $Fe^{2+} + S^= \rightarrow FeS\downarrow$
3. Type Attack – Severe pitting, embrittlement, and stress cracking, also generalized pitting and black sulfide coating.
4. Treating Agents:
   - MIL-GARD® = $2ZnCO_3 \bullet 3Zn(OH)_2$ (basic zinc carbonate)
   - MIL-GARD R = $ZnLSO_3$ (zinc lignosulfonate)
   - Lime = $Ca(OH)_2$
   - Caustic Soda = NaOH
5. Treating Methods – The most effective method of controlling H_2S involves the use of MIL-GARD (to scavenge sulfides) in conjunction with pH control, using caustic soda and/or lime, to minimize embrittlement.

   Caustic soda and/or lime should be used in the fluid system to establish an alkaline environment. In an alkaline environment, H_2S is reduced to soluble sulfides which have less tendency to cause hydrogen embrittlement. However, since soluble sulfides present in the system are corrosive and will revert to H_2S if a reduction in pH occurs, do not rely on this approach for total control.

   MIL-GARD® or MIL-GARD R is used to effectively scavenge all forms of sulfide present in the system. The reaction of MIL-GARD with sulfides is irreversible, forming insoluble zinc sulfide (ZnS), and will occur within a pH range of 3.4 to 14.

   Recommended Treatment

   - MIL-GARD® – 2 to 3 lb_m/bbl (1 lb_m/bbl = 500 mg/L sulfide), or MIL-GARD R – 6 to 8 lb_m/bbl (1 lb_m/bbl = 150 mg/L sulfide)
   - NaOH and/or $Ca(OH)_2$ for pH 10.0 or above.

Note: *MIL-GARD R should be used in clear fluids such as drillwater and brines, as MIL-GARD will settle. Maintain excess MIL-GARD in the system when H_2S is suspected or known to be present. Also MIL-GARD R may thin/disperse nondispersed fluid systems. Use the Garrett Gas Train to monitor excess MIL-GARD concentration (see* **Miscellaneous Testing Procedures**, *Chapter 1).*

   If MIL-GARD is unavailable, the next best method to treat for H_2S is pH control using lime, a filming amine to coat the pipe, and SCALE-BAN™ to prevent scale deposition. Control the pH at 10.5 or above using lime. *Do not use caustic soda alone*, because caustic reacts to form sodium sulfide (Na_2S), which is extremely soluble, and H_2S may be released from the fluid if the pH drops. *Lime is recommended* instead because it forms calcium sulfide (CaS) which is only slightly soluble and will precipitate from the system. Use AMI-TEC™ to provide a film on the drillpipe to protect against sulfide corrosion. See CO_2 Treating Methods for details.

6. Additional Notes on H_2S – The use of the Garrett Gas Train and sulfide-indicating Drager tubes is necessary to properly monitor the fluid system for quantitative information on sulfides. Techniques utilizing lead acetate paper discs are used only to indicate the presence of sulfides in relative concentration (see **Chemical Analyses**, Chapter 1).

   When testing for the presence of sulfides in a fluid, it is extremely important that the filtrate used be as fresh as possible. In addition, the filtrate should be taken from a sample of fluid freshly collected at the flowline. Minimize exposure of the fluid or filtrate to the atmosphere as this reduces the accuracy of the test.

Table 4-7 Toxicity of Hydrogen Sulfide to Man

H_2S ppm	0 - 2 Minutes	2 - 15 Minutes	15 - 30 Minutes	30 Minutes- 1 Hour	1 - 4 Hours	4 - 8 Hours	8 - 48 Hours
50 100				Mild conjunctivitis; respiratory tract irritation			
100 150		Coughing; irritation of eyes; loss of sense of smell	Disturbed respiration; pain in eyes; sleepiness	Throat irritation	Salivation and mucous discharge; sharp pain in eyes: coughing	Increased symptoms	Hemorrhage and death
150 200		Loss of sense of smell	Throat and eye irritation	Throat and eye irritation	Difficult breathing; blurred vision; light shy	Serious irritating effects	Hemorrhage and death
250 350		Irritation of eyes; loss of sense of smell	Irritation of eyes	Painful secretion of tears; weariness	Light shy; nasal catarrh; pain in eyes; difficult breathing	Hemorrhage and death	

Table 4-7 Toxicity of Hydrogen Sulfide to Man (continued)

H_2S ppm	0 - 2 Minutes	2 - 15 Minutes	15 - 30 Minutes	30 Minutes- 1 Hour	1 - 4 Hours	4 - 8 Hours	8 - 48 Hours
350 450		Irritation of eyes; loss of sense of smell	Difficult respiration; coughing; irritation of eyes	Increased irritation of eyes and nasal tract; dull pain in head; weariness; light shy	Dizziness; weakness; increased irritation; death	Death	
500 600	Coughing; collapse; unconsciousness	Respiratory disturbances; irritation of eyes; collapse	Serious eye irritation; palpitation of heart; few cases of death	Severe pain in eyes and head; dizziness; trembling at extremities; great weakness and death			
600 700 800 1500	Collapse; unconsciousness; death						
1800	Immediate death						

Types of Corrosion

1. ***General Corrosion*** – Corrosion in a uniform manner, wherein the entire surface of the metal is corroded or thinned at a uniform rate.
2. ***Pitting Corrosion*** – A highly localized corrosion attack which results in deep penetration at specific sites. Pits can initiate cracks or penetrate the drillstring, thereby causing washouts and twist-offs, resulting in expensive fishing jobs.
3. ***Stress Corrosion or Stress-Accelerated Corrosion*** – Often referred to as stress-corrosion cracking, where the cracking and possible failure of a metal is caused by a combination of tensile strength and a corrosive medium.
4. ***Hydrogen Embrittlement*** – Embrittlement of a metal caused by atomic hydrogen penetration into the metal lattice structure. This penetration lowers the ductility of the metal, which eventually results in pipe failure.
5. ***Scale/Deposition Corrosion*** – Deposition of insoluble materials on a metal surface. This deposition forms localized corrosion concentration cells which promote pitting.
6. ***Erosion Corrosion*** – A deterioration of a surface by the abrasive action of suspended solids or gas bubbles in a moving stream.
7. ***Corrosion Fatigue*** – The fatigue life of drillpipe is reduced when the pipe is cyclically stressed in a corrosive environment. Corrosion fatigue cracks can be triggered by corrosion pits, mechanical nicks, metal defects, or stress concentration caused by improper strike, make-up or connection.

Bacterial-Induced Corrosion

Casing, production, and drillstring tubulars have been known to suffer severe corrosion as the result of bacterial action. Microorganisms contribute to corrosion in different ways. Some act as cathodic depolarizes, while others form slimes or growths that shield a portion of the metal, scale, and oxygen concentration cell. Generally, microorganisms affecting corrosion are classified according to oxygen requirements. Aerobic refers to a presence of oxygen. Anaerobic refers to an absence of oxygen or low oxygen.

In aerobic environments, the species thiobacillus accounts for most of the corrosion. This species converts sulfur to sulfuric acid, which stimulates attack.

Sulfate-reducing bacteria are found in anaerobic environments. This mechanism involves both the direct attack of iron by hydrogen sulfide and cathodic depolarization. Even in aerated fluids, sulfate-reducing bacteria may be found within active corrosion pit areas where the oxygen content becomes low.

Microbiological testing using an extinction-dilution technique may be used in the Field Fluid Laboratory to identify and count the number of organisms present. Bacterial testing vials are available for both aerobic (phenol red/dextrose) and anaerobic (modified postgate media “B”) testing.

Testing procedures for both types of vials are as follows.

Inoculation of Serial Dilution Vials

1. Tape five to seven vials together in a row. Number vials 1 through 5 or 7 and label with sampling point, date, and location.
2. Remove metal tab from top of vial without removing metal seal from the stopper.
3. Using a disposable syringe, inoculate the first serum vial with 1 mL of the sampled water (or filtrate) and shake thoroughly.
4. With a new syringe, withdraw 1 mL from the first vial. Inoculate the second vial and shake thoroughly.
5. Repeat step 4 until desired number of vials have been inoculated.
6. Incubate the vials at 37°C (98°F) [or within 5°C (25°F) of system temperature] and observe daily for growth. API RP 38 recommends a 28-day incubation period for anaerobic vials and a minimum 5-day period for aerobic vials.

Interpretation of Results

Media	Positive Result
API or postgate media "B" sulfate-reducer vials	Black material forms in bottle
Phenol red vials	Media turns yellow

1. The number of vials that show positive results in the allotted time period can be used to calculate the bacteria level by Table 4-8.

   When sampling system with H_2S present, sulfate reducer vial no. 1 will often turn positive (black) within 15 to 60 seconds of inoculation. This occurrence should be considered no growth, if only this vial is turned after 28 days. If vial no. 2 turns black immediately, a new sample should be obtained and the H_2S purged with nitrogen to remove the H_2S.

Table 4-8 Bacterial Testing Levels

Bottle Number	Dilution Factor	Growth Interpretation
1	0	1 per mL
2	1:10	10 per mL
3	1:100	100 per mL
4	1:1,000	1,000 per mL
5	1:10,000	10,000 per mL
6	1:100,000	100,000 per mL
7	1:1,000,000	1,000,000 per mL

Bactericides and biocides are used to control microorganisms. Presently, INTEQ recommends the addition of 1 gal per 400 bbl of fluid of X-CIDE® 207 to control microorganisms. A bactericide does not immediately remove bacteria, so sufficient time must be allotted for their removal. Should the situation arise when a rapid kill of microorganisms is required, 1 gal per 200 bbl of X-CIDE® 105 is recommended.

Corrosivity of Various Fluids

1. ***Nondispersed*** – Oxygen entrapment and highly dissolved oxygen contents caused by high gel strengths and yield points. These fluids often have a low pH.

2. ***Low Solids*** – Corrosive due to the same rheological conditions as nondispersed fluids.
3. ***Polymer Fluids*** – Usually have lower pH and may contain salts which increase the fluid conductivity. Also, these fluids often have rheological properties which allow entrapment of oxygen, resulting in high oxygen content. NEW-DRILL®, BIO-DRILL™ 1402, and PYRO-DRILL℠ fluids routinely have low corrosion rates. This phenomena has been observed even when operating in the more corrosive environments.
4. ***Saturated Salt Fluids*** – Oxygen solubility is low but conductivity is high; chlorides increase pitting attack. These fluids may have moderately high oxygen contents due to O_2 entrapment, but this is limited by solubility.
5. ***Dispersed*** – Slightly corrosive; less oxygen entrapment due to lower gel strengths and yield points. In addition, most dispersants have some oxygen scavenging ability.
6. ***Lignosulfonates*** – Slightly corrosive; due to same conditions indicated in dispersed. Lignosulfonates are, to a certain degree, natural oxygen scavengers. In addition, lignosulfonate fluids usually have a pH high enough (9.0 or more) to greatly reduce corrosion. (However, where salts are present, conductivity may be increased, increasing corrosivity.)

Note: *Aluminum drillpipe forms an aluminum-oxide coating or film that protects it from corrosion in many environments. This film is quite stable in neutral conditions but is attacked by alkalinities. Therefore, when using aluminum drillpipe, the pH of the fluid should be at 9.0 or below.*

Use of Corrosion Coupons

Ring Coupons

The most effective method of measuring the corrosivity of a drilling fluid involves the use of preweighed ring coupons. These rings are sized to fit into the relief groove in the tool joint box (see Table 4-9). These rings are placed in the drillstring and exposed to the fluid for a period of time during the drilling operation. After exposure to the system for a minimum of 40 hours, the rings are retrieved, cleaned, and reweighed in the laboratory to within $^{1}/_{10}$ milligram.

Table 4-9 Ring Factors and Formulas (for all Metal Rings)

		Factors		Coupon Dimensions		
Series No.	**Ring Size**	**mpy**	**$lb_m/ft^2/yr$**	**I.D.**	**O.D.**	**W**
	3½ E.H.		337	$2^{5}/_{8}$"	$2^{15}/_{16}$"	$^{7}/_{16}$"
F	3½ I.F.	280	275	2¾ "	$3^{1}/_{16}$"	$^{7}/_{16}$"
H	4 F.H.	252	248	$2^{7}/_{8}$"	3¼"	$^{7}/_{16}$"
	4 I.F.			Same as 4½" E.H.		
	4 E.F.			Same as 3½" I.F.		
K	4½ F.H.	207	203	$2^{15}/_{16}$"	3½"	$^{7}/_{16}$"
N	4½ E.H.	195	192	$3^{5}/_{16}$"	$3^{13}/_{16}$"	$^{7}/_{16}$"
P	4½ I.F.	193	189	$3^{13}/_{16}$"	$4^{3}/_{16}$"	$^{7}/_{16}$"
R	5 F.H.	219	215	$3^{17}/_{32}$"	$4^{1}/_{32}$"	$^{5}/_{16}$"
	5 E.H.			Same as 4½" I.F.		
V	5½ F.H.	188	184	$4^{1}/_{32}$"	$4^{5}/_{8}$"	
	5½ E.H.			Same as 5" I.F.		
X	5½ 1.F.	148	145	$4^{7}/_{8}$"	$5^{19}/_{64}$"	$^{7}/_{16}$"
	6 E.H.			Same as 5½" I.F.		

The difference between the initial and final weights (or the weight lost) is attributed to corrosion, and the corrosion rate is calculated and reported as $lb_m/ft^2/yr$ or mils per year (mpy). The term “mils per year” refers to the loss of metal in thousandths of an inch per year. Two types of rings are available, bare uncoated steel and steel rings having a hard plastic backing.

Ring Placement and Scheduling

Placement – Corrosion coupons should be placed in the first joint of drillpipe above the bottomhole assembly and/or in the kelly saver sub or fluid saver sub above the TIW valve.

Scheduling – Ring coupons should be run in the drillstring for a minimum of 40 hours. In every instance, the time must be reported as accurately as possible, even if the coupon is left in the string for several days. A notation should document the number of hours downhole and in the derrick.

Handling of Corrosion Rings

1. Leave the ring in the shipping envelope until immediately prior to placement in the drillstring. Do not handle the ring prior to running it.
2. Wipe the recessed area inside the box end and external face of the pin end of the tool joint clean of excess fluid and pipe dope.
3. Carefully place the ring down into the recess with the beveled side down. Care should be taken to be sure that the ring lays flat within the recess to avoid mechanical damage when the joint is made up.
4. Record on the shipping envelope the location of the ring and the date and time of placement in the string. Run the ring coupon in the drillstring for a minimum of 40 hours.
5. After the run, carefully remove the ring, preventing any mechanical damage that could cause a weight loss.
6. Immediately upon its removal from the string, wash off any excess fluid and fluid solids adhering to the coupon. Wipe dry and apply a light coat of grease or heavy oil to the coupon to protect it from atmospheric corrosion. **DO NOT USE PIPE DOPE**.

7. Visually inspect the ring for mechanical damage and pitting. Record the observations. If severe pitting is noted, steps should be taken to identify and correct the cause.
8. Rewrap the ring in vapor-barrier paper and record on the shipping envelope the requested information. Be sure to record the date and time the ring was installed and removed, as well as the fluid type and any corrosion control techniques and treatments in effect during the coupon run. Ship the ring to the processing lab as soon as possible.

Calculation of Corrosion Rate

The corrosion rate, based on weight loss (from corrosion coupon analysis), is calculated as follows.

$$\text{Corrosion rate, } lb_m/ft^2/yr = \frac{\text{Wt loss, g}}{\text{Exposure time, hr}} \times K$$

$$mils\ per\ yr = lb/ft^2/yr \times 24.6$$

where

K = a constant used for the area of the ring exposed and the metal density. It is printed on the shipping envelope.

Note: *Constants for plastic-coated rings are significantly different and should not be interchanged.*

Examination of the ring can provide very low corrosion rates with deep pits present. This condition would indicate a severe corrosion problem in spite of low calculated rates of corrosion.

Drillpipe Corrosion Ring Coupon Test Procedure

The placement of corrosion test rings in the tool joints is one of the more common techniques used to evaluate the corrosiveness of drilling fluid environments on the drillstring and other steel goods. An examination of scales and pits on the exposed rings gives clues as to the cause of the corrosion, thus aiding in choosing proper remedial action.

The corrosion rings should be shipped to the field in sealed envelopes or wrappers to minimize atmospheric corrosion.

Procedure

1. Drillpipe corrosion rings should be kept in the drillstring for a minimum of 40 hours. The ring is usually placed in the tool joint at the top of the first stand above the drill collars and can be left in the drillstring for more than one bit run. An additional ring can be placed in the kelly saver sub to monitor corrosion at that point. Care should be taken to insure that the box recess is clean to prevent interference with proper makeup of the joint and to avoid damage to the ring. In some instances specially manufactured subs have been used for the ring placement in the string. During installation, the ring should be handled with clean, dry gloves only.
2. The drillpipe corrosion coupon form should be filled out completely.
3. The drilling fluid residue should be removed from the coupon by wiping with a cloth when the ring is pulled from the drillstring. The ring should be examined for severity of corrosion or mechanical damage. If severe corrosion is evident, the cause of the corrosion should be determined promptly so remedial action can be taken. Following visual observation, immediately coat the coupon with oil or other available grease (do not use thread compound for this purpose). Place in a plastic bag and then in the mailing envelope.
4. Before proceeding with a quantitative evaluation of corrosion of the ring, the ring should be rinsed with a suitable solvent, such as acetone or petroleum ether, to remove the oil applied to the ring on location. Prior to cleaning for weighing, a spot test should be made for corrosion by-products and mineral scale. The rings should be cleaned with a detergent solution and a stiff fiber bristle brush. It may be necessary to dip the ring for 5 to 10 seconds in inhibited 10% to 15% hydrochloric acid one or more times to remove corrosion products. The ring should be scrubbed with detergent solution after each acid dip. Rinse thoroughly with clean water and then with anhydrous acetone or methanol. Allow to dry prior to weighing. Harsh, abrasive materials or strong, uninhibited acids should not be used. An ultrasonic bath can be useful in cleaning the ring.

5. After the preweighed drillpipe corrosion coupon has been properly cleaned and the corrosion film and type of attack noted, the ring should be reweighed to 1 mg and the weight loss determined. If significant loss of metal due to mechanical damage is evident, it should be noted and taken into consideration in evaluating the ring. The corrosion rate may be reported as $kg/m^2/yr$, $lb_m/ft^2/yr$, or mils per year (mpy).
6. If visual corrosion is evident, it will normally be detectable as pitting corrosion. Uniform attack or general corrosion can best be determined by a weight loss measurement. Mechanical damage to the ring will most often be evidenced by cuts or dents on the outer surfaces of the ring. In some cases, the ring will exhibit a series of dents and worn spots, indicating considerable movement of the ring in the box recess.
7. Examination of the ring may reveal a few deep pits with a relatively low weight loss. This condition would indicate a rather severe corrosion problem even though the calculated corrosion rate would be considered low.

Calculation

1. The corrosion rate in mils per year (mpy) may be calculated by the following formula for steel coupons with a specific gravity of 7.86.

$$\text{mpy} = \frac{(\text{Wt loss, mg})\ (68.33)}{(\text{Area, in.}^2)\ (\text{Hours exposed})}$$

Note: *Corrosion rings available from drilling fluid service companies or corrosion test laboratories are generally supplied with a multiplication factor which includes the metal density and surface area of the ring. Thus, the weight loss divided by the exposure time need only be multiplied by the supplied factor to obtain the corrosion rate.*

Note: *The total surface area of the ring is used in these calculations. Time used based on total time in the drillstring.*

2. The following are conversion rates between the various units for steel coupons (specific gravity 7.86).
   - $lb_m/ft^2/yr = 0.0406 \times mpy$

   - $lb_m/ft^2/yr = 0.2041\ kg/m^2/yr$
   - $kg/m^2/yr = 0.1988 \times mpy$

Corrosion Treatment Tips

Oxygen Scavengers

NOXYGEN

NOXYGEN™ is a liquid and is packaged in 55-gal drums. Best application is by chemical-injection pump into the suction line. Initial injection rate should be as high as the pump will allow, reducing the rate as necessary to obtain the required sulfite residual at the flowline. Maintain 75 to 125 mg/L sulfite residual. Large diameter boreholes with high-circulation rates will require higher chemical-injection rates. All fittings and valves on the chemical-injection equipment should be of good quality stainless steel. All fittings should be air tight. **Avoid copper and brass fittings.**

Film-Forming Amines

AMI-TEC

AMI-TEC™ may be applied by spraying, dipping, or by "batch" treatments. During trips when spraying is not feasible, it is possible to treat the pipe by placing 15 to 20 gal of amine/diesel batch in the annulus below the flowline, and 5 to 10 gal of batch inside the pipe after it will "pull dry." In this manner, the pipe may be coated inside and out on trips. AMI-TEC is oil-soluble and water-dispersible. The addition of AMI-TEC to a fluid system can cause severe rheology problems and the best treatments with this material minimize its entrainment in the fluid. See Table 4-10 for the amine quantities required for slug treatment.

Scale Inhibitor

SCALE BAN

SCALE-BAN™ is a chemical inhibitor that interrupts and deforms the normal crystalline growth pattern of carbonate scales, SCALE-BAN is required in low concentrations. As little as 3 to 5 ppm in the system is effective at inhibiting scale formation. Visual inspection of the drillpipe will indicate if treatment levels are sufficient. When scale is formed, oxygen concentration cells develop beneath the scale, and severe localized pitting develops.

SCALE-BAN is suggested when carbonate gas is present or when lime is used in significant quantities in the circulating system. SCALE-BAN will not remove existing scale from the pipe.

Sandblasting or other cleaning is required to remove scale deposits already present on the pipe.

Table 4-10 Amine Quantities for Slug Treatment

O.D.	Weight / ft T&C Nominal	I.D.	Linear ft per gallon (×1000)	Min. Slug 10,000 ft or Less in gallons	Additional Slug / l000 ft Below 10,000 ft
3½"	9.50 13.30 15.50	2.992" 2.764" 2.602"	2.7382 3.2082 3.6201	8.0	1.0
4"	11.85 14.00 15.70	3.476" 3.340" 3.240"	2.0283 2.1973 2.3348	12.0	1.25
4½"	13.75 16.60 20.00	3.958" 3.826" 3.640"	1.5644 1.6745 1.8501	15.0	1.5
5"	16.25 19.50	4.408" 4.276"	1.2614 1.3407	19.0	2.0
5½"	21.90 24.70	4.778" 4.670"	1.0738 1.1240	23.0	2.5

Packer Fluid Treatment

Packer fluids are fluids left between casing and tubing. Casing packs are fluids left between casing and open hole. While these fluids may be left in place for a variety of reasons, the principal reasons are

- to inhibit corrosion and extend the life of the tubular goods;
- to provide an hydrostatic column for control of pressures in the event of a casing or tubing leak.

Packer fluids are formulated from three types of basic fluids: water-base drilling fluid, brine water, and oil-base fluid. The techniques for formulating a packer fluid are as follows.

Water-Base Drilling Fluid

1. Raise the gels to prevent the settling of solids over the extended periods at which the fluid will be stagnant.
2. Raise the pH to 11.0 with caustic soda.
3. Blend 25 to 75 gal of MUD-PAC® corrosion inhibitor uniformly into each 100 bbl of fluid to be used. The quantity of MUD-PAC used will depend on the type and severity of the corrosion problems expected and on the fluid type used.

Note: *MUD-PAC is not recommended for use in nondispersed packer fluids without careful pilot testing, as it may act as a thinner in these systems. Lower concentrations of MUD-PAC would be used in fluids that are highly treated with lignosulfonate and where the producing zone is free from damaging quantities of* H_2S *and* CO_2*. Where the producing zone contains larger concentrations of* H_2S *or* CO_2*, or where sulfate-reducing bacteria are present, higher concentrations of MUD-PAC should be used. If produced fluids contain large amounts of* H_2S*, additional treatment with MIL-GARD® may be required. Additional biocides may not be required when MUD-PAC is used.*

Brine Water

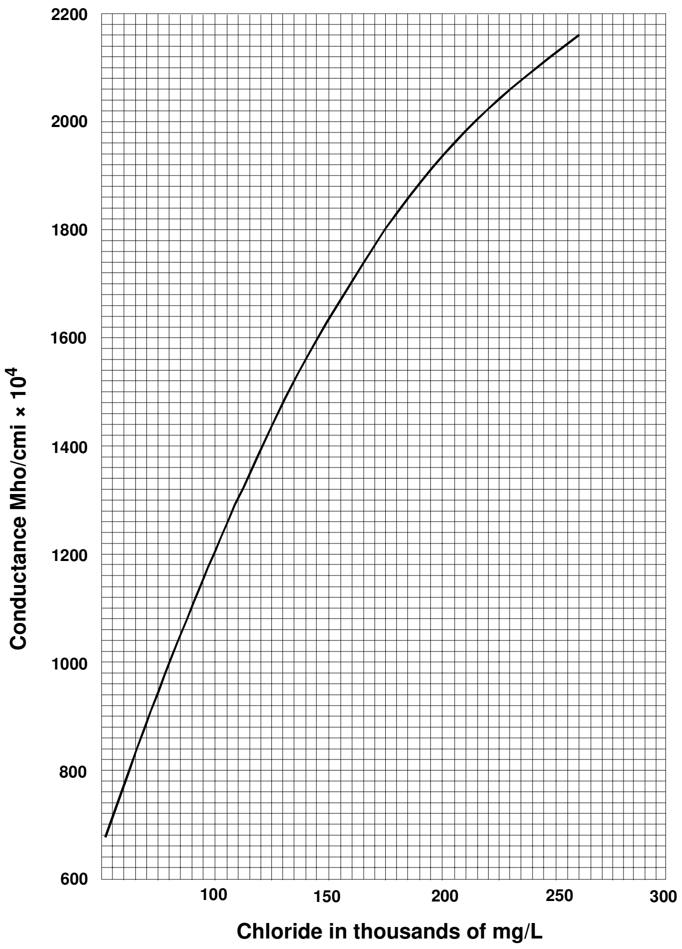
1. To raise the pH for NaCl and KCl to 10.0 to 10.5, use caustic soda (NaOH) or caustic potash (KOH). To raise the pH for high-density brines (i.e., $CaCl_2$, $CaBr_2$, etc.) and combinations of these brines, do not use caustic soda to try to raise the pH. Instead, use small amounts of lime ($CaOH_2$) and raise the pH only when absolutely necessary.
2. Add BRINE-PAC® to the brine water at a concentration of 24 gal/100 bbl brine. In severely corrosive areas it may be necessary to increase the concentration of BRINE-PAC. Do not use BRINE-PAC with brines containing solids.

3. Do not circulate or aerate brine water containing BRINE-PAC as this will expend the oxygen scavenger.
4. In areas where H_2S is a problem, add 6 to 12 lb_m/bbl of MIL-GARD® R to control sulfide corrosion.

Oil-Base Fluids

1. Because the external phase (oil) is nonconductive and noncorrosive, the addition of chemical inhibitors to oil-base fluids is unnecessary.
2. Increase the emulsion stability of the system with treatments of CARBO-TEC® and lime. This will provide the stability required for long-term packer fluid service.
3. Raise the yield point and gel strengths with CARBO-GEL® to prevent solids settling and minimize segregation. For high-temperature applications, CARBO-GEL® / CARBO-VIS™ can be supplemented with CARBO-VIS HT.
4. Increase the excess lime concentration to 5 lb_m/bbl as a precautionary measure against possible H_2S intrusion. MIL-GARD (not MIL-GARD R) may also be added.

Figure 4-31 Conductivity of Brines



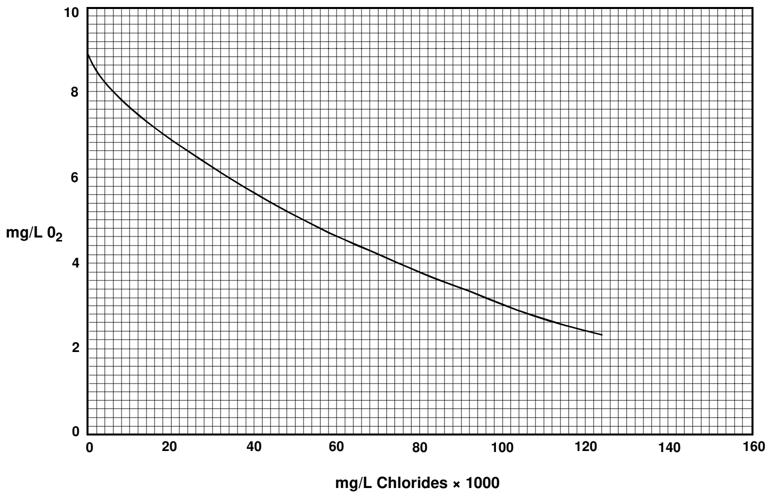


Figure 4-32 Oxygen Solubility vs. Salinity

Figure 4-33 Oxygen Solubility in Water vs. Temperature (Dry Atmosphere)

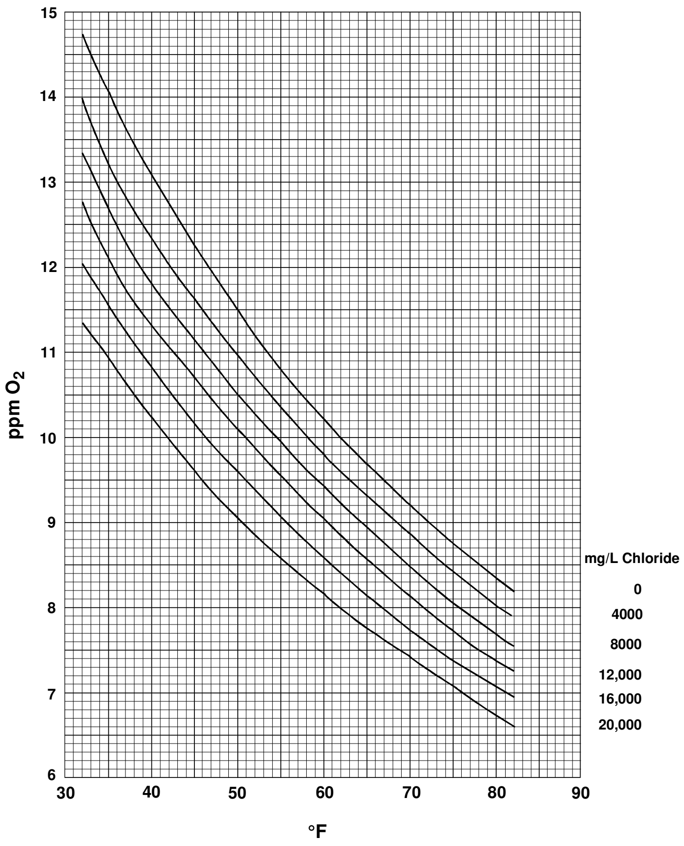


Figure 4-34 Effect of Salt Concentration on Corrosion

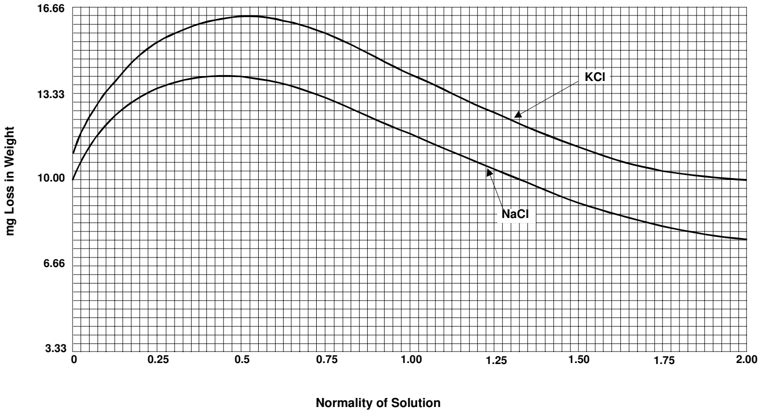


Figure 4-35 Effect of pH on Corrosion of Mild Steel

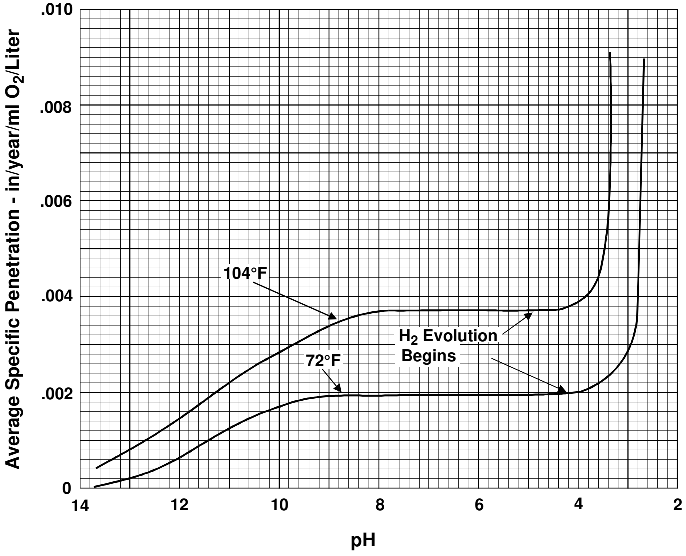
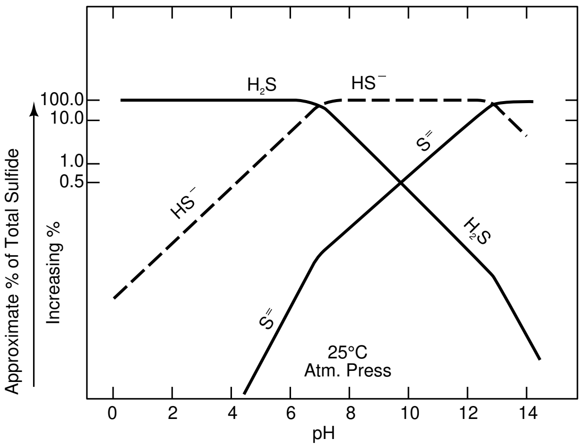


Figure 4-36 A pprox. Distribution of H_2S, HS^-,and S^{-2} as a Function of pH



Chapter 5

Formulas, Charts, Tables

This section of the Baker Hughes INTEQ Fluid Facts Engineering Handbook furnishes all of the necessary formulas, tables, and/or charts to complete the volume and circulation sections of the API Drilling Mud Report Form. Additional formulas, charts, and tables which may be required to successfully engineer the fluid system, have also been included.

The chapter is divided into the following sections:

- **General Formulas**
- **Charts and Tables**
- **Bit/Casing/Drillpipe Information**
- **Salt Tables**
- **Chemical Information**
- **Conversion Factors**
- **Metric “SI” Conversions**

General Formulas

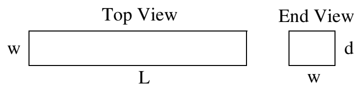
Pit Capacity Determination

The most common container for the surface volumes are rectangular pits with vertical sides and flat bottoms. Other types of pits that may be encountered are rectangular pits with sloping sides, and circular or elliptical cylindrical tanks.

Note: *All dimensions used in the following formulas are in feet.*

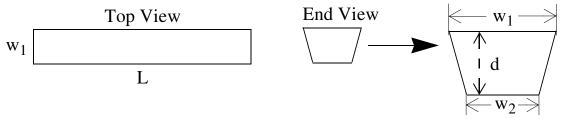
1. Rectangular Tanks with Flat Bottoms

$$\text{bbl} = \frac{(L)(w)(d)}{5.615} \qquad (5\text{-}1)$$



2. Rectangular Tanks with Sloping Sides

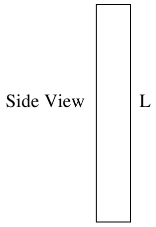
$$\text{bbl} = \frac{(L)(d)\left[\frac{w_1 + w_2}{2}\right]}{5.615} \qquad (5\text{-}2)$$

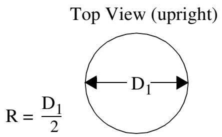


3. Circular Cylindrical Tanks

   a. ***Upright***

$$\text{bbl} = \frac{(\pi)(R^2)(L)}{5.615} \qquad (5\text{-}3)$$

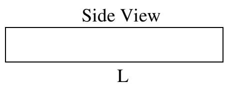


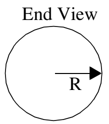


b. ***Horizontal***

- Determine the total tank capacity.

$$\text{bbl} = \frac{(\pi)(R^2)(L)}{5.615} \qquad (5\text{-}4)$$

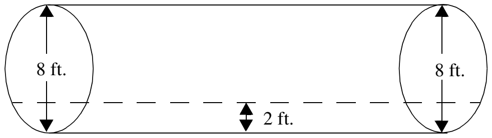




- Determine the percentage of tank diameter that is filled.

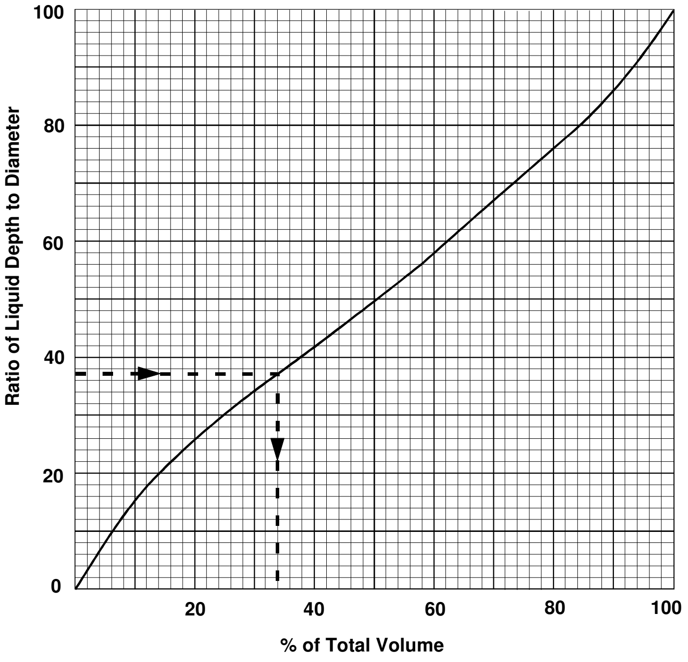
  If an 8 ft diameter tank is filled to a 2 ft level, the tank is filled to 25% of its diameter.

$$\frac{2\text{ft}}{8\text{ft}} \times 100 = 25\%$$



Use the graph below to determine the tank volume based on percentage of tank diameter filled.

Calibration Curve for Cylindrical Tanks in a Horizontal Position



Example

Diameter = 4 ft

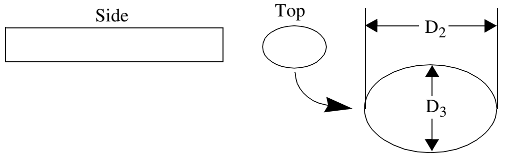
Length = 20 ft

Fluid height = 1.5 ft

- Total tank volume = $(3.14 \times 2^2 \times 20)/5.615 = 44.73$ bbl
- Ratio of liquid depth to diameter = $(1.5 \div 4) \times 100 = 37.5$
- From graph, ratio of 37.5 indicates 34% of capacity
- % of total volume = $0.34 \times 44.7 = 15.2$ bbl fluid in tank

4. Elliptical Cylindrical Tanks

$$\text{bbl} = \frac{\left[\dfrac{D_2 \times D_3}{4}\right](\pi)(d)}{5.6} \qquad (5\text{-}5)$$



Open Hole and Casing Volume (without Pipe)

$$\text{bbl/ft} = \frac{\text{I.D.}^2}{1029.4} \qquad (5\text{-}6)$$

or

$$\text{bbl} = \frac{\text{I.D.}^2}{1029.4} \times L$$

Note: *Use inside diameter (I.D.) for casing and bit diameter for open hole. Do not allow for open hole washout unless values are known from fluid (mud) logging data or caliper logs. Annular or casing capacity tables can be used in lieu of the formulas.*

Pipe Capacity

$$\text{bbl/ft} = \frac{\text{I.D.}^2}{1029.4} \qquad (5\text{-}7)$$

or

$$\text{bbl} = \frac{\text{I.D.}^2}{1029.4} \times L$$

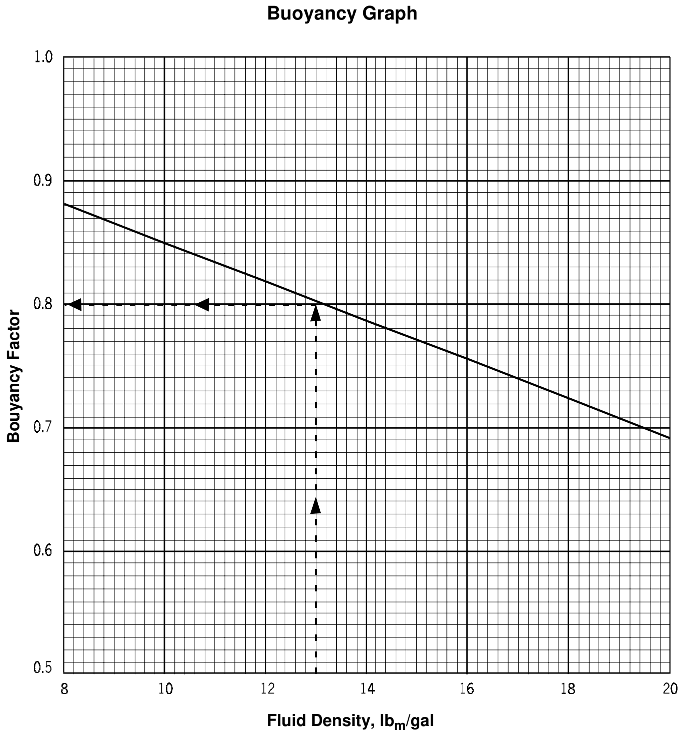
where

I.D. = inside diameter of drillpipe (in.).
Use equivalent I.D.s from pipe tables in this chapter (see **Charts and Tables**).

L = length (ft).

Pipe Displacement Obtained from Pipe Tables

Because of the varying thicknesses of the various types of tool joints, it is more accurate to read displacements from pipe tables (see **Charts and Tables**) than to calculate them, unless tool joint specs are available.


Buoyancy Graph

Example:

If the fluid weight is 13.0 lb_m/gal and the drillstring weight (in air) is 90,000 lb_m, determine the buoyed weight of the string.

- Enter the graph at the fluid weight, read up to the line, and then across (left) to the buoyancy factor.

- Determine buoyed weight by multiplying the total string weight (in air) by the factor:

$$0.8 \times 90{,}000 = 72{,}000\ \text{lb}_m.$$

Annular Volume

$$\text{bbl/ft} = \frac{\text{I.D.}^2 - \text{O.D.}^2}{1029.4} \qquad (5\text{-}8)$$

or

$$\text{bbl} = \frac{\text{I.D.}^2 - \text{O.D.}^2}{1029.4} \times L$$

where

I.D. = inside diameter of casing or bit diameter (inches),
O.D. = outside diameter of drillpipe or drill collars (in.),
L = annular section length (feet).

Pump Output

1. Duplex:

$$\text{bbl/stk} = \frac{D_l^2 - \dfrac{D_r^2}{2}}{3088.2} \times V_e \times S_l \qquad (5\text{-}9)$$

2. Triplex:

$$\text{bbl/stk} = \frac{D_l^2 \times V_e}{4117.7} \times S_l \qquad (5\text{-}10)$$

where

D_l = liner diameter (inches),

D_r = rod diameter (inches),

V_e = volumetric efficiency (decimal fraction),

S_l = stroke length (inches).

Pump outputs may be determined from pump charts in the **Charts and Tables** section of this chapter.

Annular Velocity

$$\text{AV} = \frac{24.5(\text{gpm})}{\text{I.D.}^2 - \text{O.D.}^2} \qquad (5\text{-}11)$$

where

AV = annular velocity (ft./minute),

gpm = gal/min,

I.D. = inside diameter of the hole or casing (inches),

O.D. = outside diameter of the pipe or collars (inches).

Bottoms Up (Strokes or Time)

$$\frac{\text{Annular volume (bbl)}}{\text{Pump output (bbl/stk or bbl/min)}} \qquad (5\text{-}12)$$

Total Circulating Displacement (Strokes or Time)

$$\frac{\text{Total system volume (bbl)}}{\text{Pump output (bbl/stk or bbl/min)}} \qquad (5\text{-}13)$$

where

Total system vol. = Surface volume. + Pipe capacity + Annular volume.

Hole Volume Displacement (Strokes or Time)

$$\frac{\text{Hole volume (bbl)}}{\text{Pump output (bbl/stk or bbl/min)}} \qquad (5\text{-}14)$$

where

$$\text{Hole volume} = \begin{array}{c}\text{Annular}\\ \text{volume}\end{array} + \begin{array}{c}\text{Drillpipe}\\ \text{capacity}\end{array}$$

or

$$\text{Hole volume} = \begin{array}{c}\text{Open hole}\\ \text{capacity}\end{array} - \begin{array}{c}\text{Drillstring}\\ \text{displacement}\end{array}$$

Weight Increase Using MIL-BAR (Barite)

$$X = \frac{1470(W_2 - W_1)}{(35 - W_2)} \qquad (5\text{-}15)$$

where

X = sacks of MIL-BAR®/100 bbl fluid (100 lb_m sacks),
W_1 = initial fluid weight (lb_m/gal),
W_2 = desired fluid weight (lb_m/gal).

Volume Increase Using MIL-BAR (Barite)

$$V = \frac{100(W_2 - W_1)}{(35 - W_2)} \qquad (5\text{-}16)$$

where

V = volume increase/100 bbl fluid,
W_1 = initial fluid weight (lb_m/gal),
W_2 = desired fluid weight (lb_m/gal).

Weight Increase Using DENSIMIX (Hematite)

$$X = \frac{1749(W_2 - W_1)}{(41.7 - W_2)} \qquad (5\text{-}17)$$

where

X = sacks of DENSIMIX®/100 bbl fluid (100 lb_m sacks),
W_1 = initial fluid weight (lb_m/gal),
W_2 = desired fluid weight (lb_m/gal).

Volume Increase Using DENSIMIX (Hematite)

$$V = \frac{100(W_2 - W_1)}{(41.7 - W_2)} \qquad (5\text{-}18)$$

where

V = volume increase/100 bbl of fluid,
W_1 = initial fluid weight (lb_m/gal),
W_2 = desired fluid weight (lb_m/gal).

Weight Increase Using W.O. 30 (Calcium Carbonate)

$$X = \frac{944.6(W_2 - W_1)}{(22.5 - W_2)} \qquad (5\text{-}19)$$

where

X = sacks of W.O. 30™/100 bbl fluid (100 lb_m sacks),
W_1 = initial fluid weight (lb_m/gal),
W_2 = desired fluid weight (lb_m/gal).

Volume Increase Using W.O. 30 (Calcium Carbonate)

$$V = \frac{100(W_2 - W_1)}{(22.5 - W_2)} \qquad (5\text{-}20)$$

where

V = volume increase/100 bbl of fluid,
W_1 = initial fluid weight (lb_m/gal),
W_2 = desired fluid weight (lb_m/gal).

Weight Reduction with Freshwater

$$X = \frac{V_i(W_1 - W_2)}{(W_2 - 8.33)} \qquad (5\text{-}21)$$

where

X= bbl of water required,
V_i= initial volume (bbl),
W_1 = initial fluid weight (lb_m/gal),
W_2 = desired fluid weight (lb_m/gal).

Weight Reduction with Oil

$$X = \frac{V_i(W_1 - W_2)}{(W_2 - 7.00^*)} \qquad (5\text{-}22)$$

** Specific gravity of oil = 0.84*

where

X = bbl of oil required,

V_i = initial volume (bbl),

W_1 = initial fluid weight (lb_m/gal),

W_2 = desired fluid weight (lb_m/gal).

Mixing Liquids of Different Densities

$$V_A + V_B = V_T \tag{5-23}$$

$$(V_A)(W_A) + (V_B)(W_B) = (V_T)(W_T) \tag{5-24}$$

where

V_A = volume of first fluid (bbl),

V_B = volume of second fluid (bbl),

V_T = final volume (bbl),

W_A = weight of first fluid (lb_m/gal),

W_B = weight of second fluid (lb_m/gal),

W_T = weight of combined fluids or final weight (lb_m/gal).

Note: *This formula assumes fluids are totally miscible, no precipitation reactions occur, and fluids are of comparable salinity. This equation does not apply to the mixing of high density brine fluids.*

Fluid Density Increase for Slugging Pipe

$$\Delta D = \frac{(MW)(L_{DP})(DP_{cap})}{V_{slug}}$$

where

ΔD = Fluid density increase (lbs/gal),

MW = Current fluid density (lbs/gal),

DP_{cap} = Drill pipe capacity (bbl/ft),

V_{slug} = Slug volume, usually 30 - 50 bbls,

L_{DP} = Desired length of dry pipe, usually 500 - 800 ft.

Charts and Tables

Calculations are often expedited by using standard parameter values and/or measurements from data tables. The tables in this section contain the following information:

- **Displacement of Triplex Fluid Pumps**
- **Displacement of Duplex Fluid Pumps**
- **Capacity of Hole**
- **Capacity of Casing**
- **Drillpipe Capacity and Displacement**
- **Drill Collar Capacity and Displacement**
- **Tubing Capacity and Displacement**
- **Drillpipe Capacity/Displacement & Hole/Annular Capacity**

Displacement of Triplex Fluid Pumps

Displacement of Triplex Fluid Pumps (bbl per Stroke - 100% Efficiency)

Liner Size	Stroke length (in.)								
(in)	7.00	7.50	8.00	8.50	9.00	9.25	10.00	11.00	12.00
3.00	0.0153	0.0164	0.0175	0.0186	0.0197	0.0202	0.0219	0.024	0.0262
3.25	0.01795	0.0192	0.0205	0.0218	0.0231	0.0237	0.0257	0.0283	0.0307
3.50	0.0208	0.0223	0.0238	0.0252	0.0267	0.0276	0.0298	0.0326	0.0357
3.75	0.0238	0.0257	0.0273	0.0290	0.0307	0.0317	0.034	0.0376	0.0408
4.00	0.0271	0.029	0.0311	0.033	0.035	0.036	0.0388	0.0429	0.0467
4.25	0.0307	0.0328	0.035	0.0374	0.0395	0.0404	0.0438	0.0483	0.0526
4.50	0.0345	0.0369	0.0392	0.0419	0.0443	0.0455	0.0493	0.054	0.0590
4.75	0.0383	0.0411	0.0438	0.0466	0.0493	0.0507	0.0547	0.0602	0.0657
5.00	0.0426	0.0455	0.0486	0.0517	0.0548	0.0562	0.0607	0.0669	0.0729
5.25	0.0469	0.0502	0.0535	0.0569	0.0602	0.062	0.0669	0.0736	0.0802
5.50	0.0514	0.055	0.0588	0.0624	0.0661	0.0678	0.0736	0.0807	0.088
5.75	0.0562	0.0602	0.0643	0.0683	0.0721	0.0743	0.0802	0.0883	0.0964
6.00	0.0611	0.0655	0.070	0.0743	0.0786	0.0809	0.0874	0.0961	0.105
6.25	0.0664	0.0712	0.0759	0.0807	0.0855	0.0878	0.0948	0.1043	0.1138
6.50	0.0719	0.0719	0.0821	0.0871	0.0924	0.0949	0.1026	0.1129	0.123
6.75	0.0774	0.083	0.0886	0.094	0.0995	0.1023	0.1107	0.1217	0.1328
7.00	0.833	0.893	0.0952	0.101	0.1071	0.11	0.119	0.131	0.143

Displacement of Duplex Fluid Pumps

Displacement of Duplex Fluid Pumps (bbl per Stroke - 100% Efficiency)

	Stroke length (in.)					
	12	14	15	16	18	20
Liner Size (in.)	Rod Diameter (in.) 2.00	2.00	2.25	2.25	2.50	2.50
4.00	0.055	0.064	—	—	—	—
4.25	0.062	0.073	—	—	—	—
4.50	0.071	0.083	0.086	0.096	0.099	0.111
4.75	0.080	0.093	0.097	0.104	0.113	0.126
5.00	0.089	0.104	0.109	0.116	0.127	0.142
5.25	0.099	0.116	0.121	0.129	0.142	0.158
5.50	0.110	0.128	0.135	0.144	0.158	0.176
5.75	0.121	0.141	0.149	0.158	0.174	0.194
6.00	0132	0.154	0.162	0.173	0.192	0.213
6.25	0.144	0.168	0.178	0.189	0.209	0.233
6.50	0.156	0.182	0.193	0.206	0.228	0.253
6.75	0.169	0.197	0.209	0.223	0.247	0.275
7.00	0.183	0.213	0.226	0.241	0.267	0.297
7.25	0.196	0.229	0.243	0.259	0.288	0.320
7.50	—	—	0.261	0.278	0.310	0.344
7.75	—	—	0.279	0.298	0.332	0.369

Capacity of Hole

Bit Size *		Barrels per Linear Foot	Linear Feet per Barrel
(in)	(mm)		
3.750	95.2	0.01366	73.2064
3.875	98.4	0.01459	68.5553
4.125	104.8	0.0165	60.6061
4.500	114.3	0.0197	50.7614
4.625	117.5	0.0208	48.0769
4.750	120.6	0.0219	45.6621
5.875	149.2	0.0335	29.8507
6.000	152.4	0.0350	28.5714
6.125	155.6	0.0364	27.4725
6.250	158.7	0.0380	26.3158
6.500	165.1	0.0410	24.3902
6.750	171.4	0.0443	22.5734
7.875	200.0	0.0602	16.6113
8.375	212.7	0.0681	14.6843
8.500	215.9	0.0702	14.2450
8.750	222.2	0.0744	13.4409
9.000	228.6	0.0787	12.7065
9.500	241.3	0.0877	11.4025
9.875	250.8	0.0947	10.5597
10.625	269.9	0.1097	9.1158
11.000	279.4	0.1175	8.5106
12.250	311.1	0.1458	6.8587
13.500	342.9	0.1770	5.6497
13.750	349.3	0.1837	5.4437
14.750	374.6	0.2113	4.7316
15.000	381.0	0.2086	4.5752
17.500	444.5	0.2975	3.3614
20.000	508.0	0.3886	2.5733
24.000	609.6	0.5595	1.7873
26.000	660.4	0.6567	1.5228

**For bit sizes not listed, use Eqn.5-6 in the General Formula section.*

Capacity of Casing

O.D.		Wt / Ft w/Couplings (lb_m)	I.D.		Barrels per Linear Foot
(in.)	(mm)		(in.)	(mm)	
4.50	114.3	9.50	4.090	103.9	0.0163
4.50	114.3	10.50	4.052	102.9	0.0160
4.50	114.3	11.60	4.000	101.6	0.0155
4.50	114.3	13.50	3.920	99.6	0.0149
5.00	127.0	15.00	4.408	112.0	0.0189
5.00	127.0	18.00	4.276	108.6	0.0178
5.00	127.0	20.30	4.183	106.3	0.0170
5.00	127.0	23.20	4.046	102.8	0.0159
5.50	139.7	14.00	5.012	127.3	0.0244
5.50	139.7	15.00	4.974	126.3	0.0240
5.50	139.7	15.50	4.950	125.7	0.0238
5.50	139.7	17.00	4.892	124.3	0.0232
5.50	139.7	20.00	4.778	121.4	0.0222
5.50	139.7	23.00	4.670	118.6	0.0212
6.625	168.28	17.00	6.135	155.8	0.0365
6.625	168.28	20.00	6.049	153.6	0.0355
6.625	168.28	24.00	5.921	150.4	0.0341
6.625	168.28	28.00	5.791	147.1	0.0326
6.625	168.28	32.00	5.675	144.1	0.0312
7.00	177.8	20.00	6.456	164.0	0.0405
7.00	177.8	23.00	6.366	161.7	0.0393
7.00	177.8	26.00	6.276	159.4	0.0383
7.00	177.8	29.00	6.184	156.0	0.0371
7.00	177.8	32.00	6.094	154.8	0.0360
7.00	177.8	35.00	6.004	152.5	0.0350
7.625	193.7	26.40	6.969	177.0	0.0472
7.625	193.7	29.70	6.875	174.6	0.0459
7.625	193.7	33.70	6.765	171.8	0.0445
7.625	193.7	39.00	6.624	168.3	0.0426
8.625	219.1	24.00	8.097	205.7	0.0637

Capacity of Casing (continued)

O.D. (in.)	O.D. (mm)	Wt / Ft w/Couplings (lb_m)	I.D. (in.)	I.D. (mm)	Barrels per Linear Foot
8.625	219.1	28.00	8.017	203.6	0.0624
8.625	219.1	32.00	7.921	201.2	0.0610
9.625	244.5	32.30	9.001	228.6	0.0787
9.625	244.5	36.00	8.921	226.6	0.0773
9.625	244.5	40.00	8.835	224.4	0.0758
9.625	244.5	43.50	8.755	222.4	0.0745
9.625	244.5	47.00	8.681	220.5	0.0732
9.625	244.5	53.50	8.535	216.8	0.0708
10.750	273.1	32.75	10.192	258.9	0.1009
10.750	273,1	40.50	10.050	255.3	0.0981
10.750	273.1	45.50	9.950	252.7	0.0962
10.750	273.1	51.00	9.850	250.2	0.0943
11.750	298.5	38.00	11.150	283.2	0.1207
11.750	298.5	42.00	11.084	281.5	0.1193
11.750	298.5	47.00	11.000	279.4	0.1175
11.750	298.5	54.00	10.880	276.4	0.1150
11.750	298.5	60.00	10.772	273.6	0.1127
13.375	339.7	54.50	12.615	330.4	0.1546
13.375	339.7	61.00	12.515	317.9	0.1522
13.375	339.7	68.00	12.415	315.3	0.1497
13.375	339.7	72.00	12.347	313.6	0.1481
16.000	406.4	65.00	15.250	387.4	0.2259
16.000	406.4	75.00	15.124	384.1	0.2222
16.000	406.4	84.00	15.010	381.3	0.2189
20.000	508.0	94.00	19.124	485.7	0.3553
20.000	508.0	106.50	19.000	482.6	0.3507
20.000	508.0	133.00	18.542	470.9	0.3408
*21.000	533.4	_	20.000	508.0	0.3886
*21.000	533.4	_	19.750	501.6	0.3789
*21.000	533.4	_	19.626	498.5	0.3742

* *Common risers.*

Drillpipe Capacity and Displacement

Drillpipe Capacity and Displacement

O.D. (in.)	O.D. (mm)	Tool Joint (in.)	Tool Joint (mm)	Equivalent I.D. (in.)	Equivalent I.D. (mm)	Tool Joint Connection	Weight (lb_m/ft)	Capacity (bbl/ft)	Displacemt. (bbl/ft)
2.375	60.325	1.75	44.45	1.815	46.1	Internal Flush	6.65	0.00320	0.00249
2.875	73.03	2.125	53.975	2.151	54.61	Internal Flush	10.40	0.004495	0.003994
3.5	88.9	2.6875	68.26	2.764	70.1	Internal Flush	13.30	0.007421	0.004839
3.5	88.9	2.5625	65.08	2.60	66.04	Internal Flush	15.50	0.006577	0.005639
4.0	101.6	3.25	82.55	3.34	80.772	Internal Flush	14.00	0.01084	0.005093
4.5	114.3	2.25	57.15	3.54	89.9	Regular API	16.60	0.01217	*
4.5	114.3	3.00	76.20	3.76	95.5	Full Hole	16.60	0.01373	*
4.5	114.3	3.25	82.55	3.78	96.01	Xtra Hole	16.60	0.01388	*
4.5	114.3	3.75	95.25	3.826	97.03	Internal Flush	16.60	0.014219	0.006390
5.0	127.0	3.75	95.25	4.23	107.4	Xtra Hole	19.50	0.018876	0.005457
5.0	127.0	3.50	88.9	3.97	100.8	Xtra Hole	25.60	0.01776	0.00709
5.5	139.7	2.75	69.85	4.40	111.8	Regular	21.90	*	*
5.5	139.7	4.8125	122.24	4.80	121.9	Internal Flush	21.90	0.0220	0.008037
6.625	168.3	5.9063	150.02	5.96	151.38	Internal Flush	25.20	0.0345	0.00807
Hevi-Wate Drillpipe Capacity									
3.5	88.9	*	*	2.08	52.83	*	26.0	0.0042	*
4.0	101.6	*	*	2.58	65.5	*	28.0	0.00647	*
4.5	114.3	*	*	2.77	70.4	*	42.0	0.00745	*
5.0	127.0	*	*	3.02	76.7	*	50.0	0.00886	*

Drill Collar Capacity and Displacement

O.D		I.D		Wt	Capacity	Displace.
(in.)	(mm)	(in.)	(mm)	(lb_m/ft)	(bbl/ft)	(bbl/ft)
3.125	79.4	1.25	31.75	22.0	0.00151	0.00796
3.50	88.9	1.5	38.1	26.7	0.00218	0.00971
3.75	95.25	1.5	38.1	31.6	0.00218	0.01147
4.00	101.6	2.0	50.8	32.0	0.0039	0.0116
4.25	108.0	2.0	50.8	37.5	0.0039	0.0136
4.50	114.3	2.25	57.2	40.6	0.0049	0.0148
4.75	120.65	2.25	57.2	46.8	0.0049	0.0170
5.00	127.0	2.25	57.2	53.3	0.0049	0.0194
5.25	133.5	2.25	57.2	60.1	0.0049	0.0219
5.50	139.7	2.25	57.2	67.3	0.0049	0.0245
5.75	146.1	2.25	57.2	74.8	0.0049	0.0272
6.00	152.4	2.25	57.2	82.6	0.0049	0.0301
6.25	158.8	2.25	57.2	90.5	0.0049	0.0329
6.25	158.8	2.8125	71.4	83.8	0.0077	0.0303
6.50	166.1	2.25	57.2	99.5	0.0049	0.0362
6.50	166.1	2.8125	71.4	92.8	0.0077	0.0334
6.75	171.5	2.8125	71.4	102.0	0.0077	0.366
7.00	177.8	2.8125	71.4	111.0	0.0077	0.399
7.25	184.1	2.8125	71.4	120.0	0.0077	0.0434
7.50	190.5	2.8125	71.4	130.0	0.0077	0.0469
7.75	196.8	2.8125	71.4	140.0	0.0077	0.0507
8.00	203.4	2.25	57.2	157.5	0.0049	0.0573
8.00	203.4	3.00	76.2	147.0	0.0087	0.0535
8.00	203.4	2.8125	71.4	151.0	0.0077	0.0545
8.25	209.5	3.00	76.2	158.0	0.0087	0.0575
8.50	215.9	3.00	76.2	169.0	0.0087	0.0615
8.75	222.3	3.00	76.2	181.0	0.0087	0.0658
9.00	228.6	3.00	76.2	192.0	0.00874	0.06994
9.25	234.95	3.00	76.2	205.0	0.00874	0.07437
9.50	241.3	3.00	76.2	217.0	0.00874	0.07892
9.75	247.7	3.00	76.2	230.0	0.00874	0.08360
10.00	254.0	3.00	76.2	243.0	0.00874	0.08839
11.00	279.4	3.00	76.2	299.0	0.00874	0.10880

Tubing Capacity and Displacement

O.D		I.D		Weight	Capacity	Displacement
(in.)	(mm)	(in.)	(mm)	(lb_m/ft)	(bbl/ft)	(bbl/ft)
2.375	60.3	1.995	50.6	4.60	0.00387	0.00167
2.875	73.0	2.441	62.0	6.40	0.00579	0.00233
3.500	88.9	2.992	75.9	10.20	0.00829	0.00370
4.000	101.6	3.476	88.3	11.00	0.01174	0.00400
4.500	114.3	3.958	100.5	12.60	0.01522	0.00458

Drillpipe Capacity/Displacement & Hole/Annular Capacity

Drillpipe				Hole		
O.D. (in.)	Nom. Wt. (lb_m/ft)	Displace. (bb/ft)	Capacity (bbl/ft)	Size (in.)	Hole Cap. (bbl/ft)	Annular Cap. (bbl/ft)
2.375	6.65	0.002419	0.00320	4.250	0.0175	0.0119
	6.65	0.002419	0.00320	4.750	0.0219	0.0164
2.875	10.40	0.003784	0.004495	4.750	0.0219	0.0136
	10.40	0.003784	0.004495	5.625	0.0307	0.0224
	10.40	0.003784	0.004495	6.125	0.0364	0.0284
1.500	13.30	0.004839	0.007421	6.125	0.0364	0.0241
	13.30	0.004839	0.007421	6.625	0.0426	0.0307
	15.50	0.005639	0.006576	6.750	0.0443	0.0324
				7.750	0.0583	0.0464
4.000	14.00	0.005093	0.010836	7.750	0.0583	0.0423
	14.00	0.005093	0.010836	8.500	0.0702	0.0546
				8.750	0.0744	0.0588
4.500	16.60	0.006390	0.014219	7.875	0.0602	0.0396
	16.60	0.006390	0.014219	8.500	0.0702	0.0496
	16.60	0.006390	0.014219	8.750	0.0744	0.0538
	16.60	0.006390	0.014219	9.875	0.0947	0.0741
				12.250	0.1458	0.1252
5.000	19.50	0.007094	0.017762	8.500	0.0702	0.0453
	19.50	0.007094	0.017762	9.8751	0.0947	0.0698
				0.875	0.1149	0.0900
				12.250	0.1458	0.1209

Bit/Casing/Drillpipe Information

This section contains the following information:

- **Milled Tooth Bit Comparison by Type**
- **Insert Bit Comparison by Type**
- **Area of Jet Nozzles**
- **Diamond Bit Weight Recommendation**
- **Strength of Casing**
- **Bit and Casing Combination**
- **Pump Discharge Fluid Volumes**
- **Strength of Drillpipe and Drill Tubing in psi**
- **Surface Connection Combinations: Component Length-I.D.**
- **Drillpipe and Tool Joint Condition: Color Code ID**

Milled Tooth Bit Comparison by Type

Formation Type	IADC Code	Hughes	Reed	Security	Smith
Soft	111	R1	Y11	S3S	DS/DJ
	114	X3A	S11	S33S	SDS
	115	XG3A	—	—	—
	116	ATJ-1	HP11	S33SF	FDS
	121	R2	Y12	S3/S3T	DT
	124	J2T/J2	—	S33	SDT
	126	JG2	HP12	S33F	FDT
	127	R3	—	—	—
	131	X1G	Y13	S4/S4T	DG
	134	XGG	—	S44	SDG
	135	J3	S13G	S44G	SDGH
	136	JG3	—	S44F	FDG
	137		HP13G	S44GF	FDGH
Soft to Medium	211	R4	Y21	M4N	V2
	214	XV	—	M44N	SV
	215	XGV	S21 G	M44NG	SVH
	216	J4	—	M44NF	FV
	217	JG4	HP21 G	—	FVH
	235	XGC		—	—
Medium to Hard	311	—	Y31	H7	L4
	316	J7	—	—	—
	317	JG7	HP31G	—	—
	346	J8	—		

Insert Bit Comparison by Type

Formation Type	IADC Code	Hughes	Reed	Security	Smith
Soft to Medium	437	ATJ-11/ATJ-115	HP43A	S82F	F1
	517	ATJ-22/ATJ-22S	HP51	S84F	A1/F2
	527	ATJ-22C	HP52	S85F	F27
	537	ATJ-33/ATJ-33S/ ATJ-33A	HP53	S86F	F3
	547	ATJ-33C	HP54	S88F	F37
Medium to Hard	612	G44	—	—	4JA/4GA
	617	ATJ-44/ATJ-44A	HP61	M84F	F4/F45
	627	ATJ-44C	HP62	M89TF	F5
	637	ATJ-55R/ATJ-55/ ATJ-55A	HP63	M89F	F57/F47

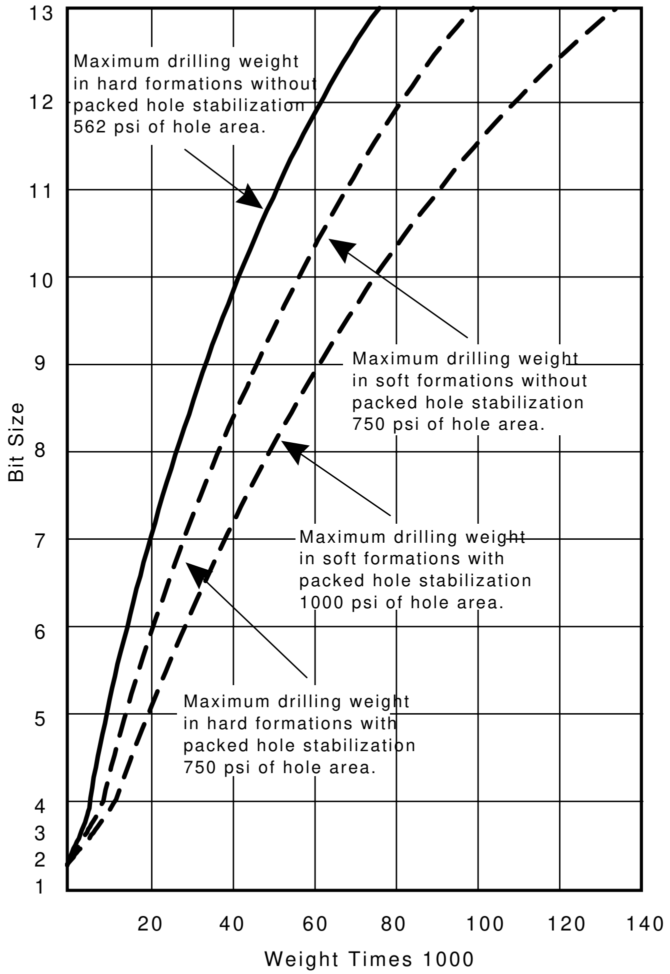
Insert Bit Comparison by Type (continued)

Formation Type	IADC Code	Hughes	Reed	Security	Smith
Hard	732 737	G77 ATJ-77	Y73JA HP73	— H87F	7JA/7GA F7
Extra Hard	837	ATJ-99A/ATJ-99	HP83	H100F	F9

Area of Jet Nozzles

Noz. Size (32nd in.)	Area* of One (in ^{2})	Area* of Two (in ^{2})	Area* of Three (in ^{2})	Area* of Four (in ^{2})	Area* of Five (in ^{2})	Area* of Six (in^2)
7	0.0376	0.0752	0.1127	0.1503	0.1879	0.2255
8	0.0491	0.0982	0.1473	0.1963	0.2454	0.2945
9	0.0621	0.1242	0.1864	0.2485	0.3106	0.3728
10	0.0767	0.1534	0.2301	0.3068	0.3835	0.4602
11	0.0928	0.1856	0.2784	0.3712	0.4640	0.5568
12	0.1104	0.2209	0.3313	0.4418	0.5522	0.6627
13	0.1296	0.2592	0.3889	0.5185	0.6481	0.7777
14	0.1503	0.3007	0.4510	0.6013	0.7517	0.9020
15	0.1726	0.3451	0.5177	0.6903	0.8629	1.0354
16	0.1963	0.3927	0.5890	0.7854	0.9817	1.1781
18	0.2485	0.4970	0.7455	0.9940	1.2425	1.4910
20	0.3068	0.6136	0.9204	1.2272	1.5340	1.8408
22	0.3712	0.7424	1.1137	1.4849	1.8561	2.2273
24	0.4418	0.8836	1.3254	1.7671	2.2089	2.6507
26	0.5185	1.0370	1.5555	2.0739	2.5924	3.1109
28	0.6013	1.2026	1.8040	2.4053	3.0066	3.6079
30	0.6903	1.3806	2.0709	2.7612	3.4515	4.1417
32	0.7854	1.5708	2.3562	3.1416	3.9270	4.7124

Diamond Bit Weight Recommendation



Maximum drilling weight in hard formations without packed hole stabilization 562 psi of hole area.

Maximum drilling weight in soft formations without packed hole stabilization 750 psi of hole area.

Maximum drilling weight in soft formations with packed hole stabilization 1000 psi of hole area.

Maximum drilling weight in hard formations with packed hole stabilization 750 psi of hole area.

Source: Hughes Christensen

Strength of Casing

Casing O. D. (in.)	Weight (lb$_m$/ft)	Grade	Burst psi*	Collapse psi*	Tensile psi*
5.500	13.00	F-25	1,810	1,660	95,000
	14.00	H-40	3,110	2,140	139,000
	15.50	J-55	4,810	3,860	211,000
	17.00	N-80	7,740	5,890	320,000
	17.00	P-110	10,640	8,520	418,000
**6.000	15.00	F-25	1,740	1,540	108,000
	18.00	H-40	3,360	2,780	179,000
	18.00	J-55	4,620	3,620	239,000
	18.00	N-80	6,720	4,740	323,000
	23.00	P-110	12,190	10,380	565,000
6.625	17.00	F-25	1,620	1,370	121,000
	20.00	H-40	3,040	2,360	195,000
	20.00	J-55	4,180	3,060	259,000
	24.00	N-80	7,440	5,550	430,000
	24.00	†P-110	10,230	7,850	562,000
7.000	17.00	F-25	1,440	1,100	118,000
	17.00	H-40	2,310	1,370	160,000
	20.00	J-55	3,740	2,500	254,000
	26.00	N-80	7,240	5,320	460,000
	26.00	†P-110	9,960	7,220	602,000
7.625	20.00	F-25	1,430	1,100	138,000
	24.00	H-40	2,750	1,970	227,000
	26.40	J-55	4,140	3,010	333,000
	26.40	N-80	6,020	3,930	439,000
	29.70	†P-110	9,470	6,180	661,000
8.625	24.00	F-25	1,340	950	161,000
	28.00	H-40	2,470	1,580	252,000
	24.00	J-55	2,950	1,430	288,000
	36.00	N-80	6,490	4,470	581,000
	40.00	†P-110	10,040	7,420	858,000
9.625	29.30	F-25	1,280	860	85,000
	32.30	H-40	2,270	1,320	279,000
	36.00	J-55	3,520	2,220	422,000
	40.00	N-80	5,750	3,530	606,000
	43.50	†P-110	8,700	4,760	875,000

Strength of Casing (continued)

Casing O. D. (in.)	Weight (lb$_m$/ft)	Grade	Burst psi*	Collapse psi*	Tensile psi*
10.750	32.75	F-25	1,140	650	196,000
	32.75	H-40	1,820	830	265,000
	40.50	J-55	3,130	1,730	450,000
	51.00	N-80	5,860	3,750	680,000
	51.00	†P-110	8,060	3,750	890,000
11.750	38.00	F-25	1,120	620	220,000
	42.00	H-40	1,980	940	222,000
	47.00	J-55	3,070	1,630	507,000
	60.00	N-80	5,830	3,680	778,000
13.375	48.00	F-25	1,080	560	260,000
	48.00	H-40	1,730	740	352,000
	54.50	J-55	2,730	1,140	545,000
	72.00	N-80	5,380	2,880	868,000
16.000	55.00	F-25	850	290	258,000
	65.00	H-40	1,640	640	423,000
	75.00	J-55	2,630	1,010	662,000
20.000	94.00	F-25	960	410	359,000
	94.00	H-40	1,530	487	487,000

** Collapse, internal yield, and joint yield strengths are minimum values with no safety factor. (Reproduced by permission of API Bulletin 5C2, bulletin on Performance of Casing and Tubing.)*

*** Not API standard. Shown for information only.*

† Tentative API standard.

Bit and Casing Combination

Casing O.D. (in.)	Weight (lb_m/ft)	Casing I.D. (in.)	Casing Drift	Bit Size (in.)	Standard Bit Pin Thread
4.50	9.5	4.090	3.965	3.875	2.375 API Regular
	10.5	4.052	3.927	3.875	
	11.6	4.000	3.875	3.875	
	13.5	3.920	3.795	3.750	
5.00	15.0	4.408	4.283	4.25	2.375 API Regular
	18.0	4.276	4.151	4.125	
5.50	14.0	5.012	4.887	4.75	2.875 API Regular
	15.5	4.950	4.825	4.75	
	17.0	4.892	4.767	4.75	
	20.0	4.778	4.653	4.625	
	23.0	4.670	4.545	4.50	2.375 API Regular
6.625	17.0	6.135	6.010	6.00	3.50 API Regular
	20.0	6.049	5.924	5.875	
	24.0	5.921	5.796	5.625	
	28.0	5.791	5.666	5.625	
	32.0	5.675	5.550	5.375	
7.00	20.0	6.456	6.331	6.25	3.50 API Regular
	23.0	6.366	6.241	6.25	
	26.0	6.276	6.151	6.125	
	29.0	6.184	6.059	6.00	
	32.0	6.094	5.969	6.00	
	35.0	6.004	5.879	5.875	
7.625	26.4	6.969	6.844	6.75	3.50 API Regular
	29.7	6.875	6.750	6.75	
	33.7	6.765	6.640	6.625	
	39.0	6.625	6.500	6.50	
8.625	24.0	8.097	7.972	7.875	4.50 API Regular
	28.0	8.017	7.892	7.875	
	32.0	7.921	7.796	7.625	
9.625	32.3	9.001	8.845	8.75	4.50 API Regular
	36.0	8.921	8.765	8.75	
	40.0	8.835	8.679	8.625	
	43.5	8.755	8.599	8.625	
	47.0	8.681	8.525	8.50	
	53.5	8.535	8.379	8.375	

Bit and Casing Combination (continued)

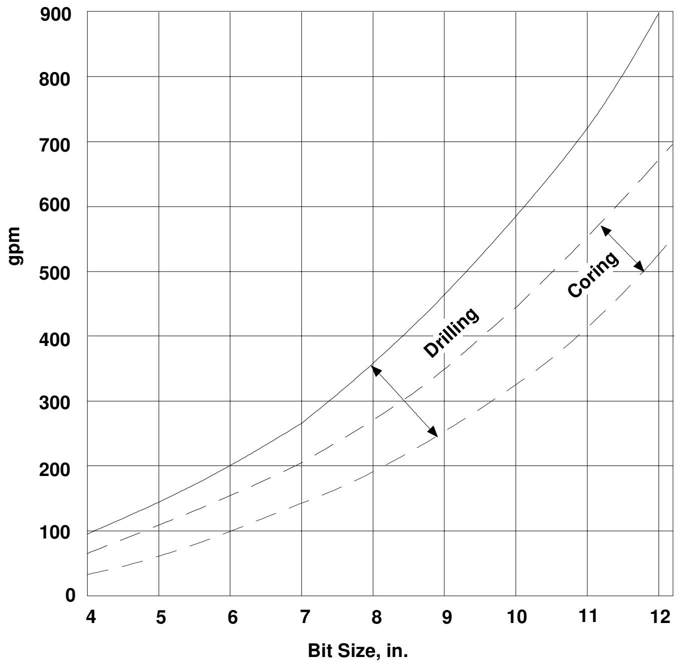
Casing O.D. (in.)	Weight (lb_m/ft)	Casing I.D. (in.)	Casing Drift	Bit Size (in.)	Standard Bit Pin Thread
10.75	32.75	10.192	10.036	9.875	6.625 API Regular
	40.5	10.050	9.894	9.875	
	45.5	9.950	9.794	*9.750	
	51.0	9.850	9.694	*9.625	
11.75	38.0	11.150	10.994	11.00	6.625 API Regular
	42.0	11.084	10.928	10.75	
	47.0	11.000	10.844	*10.75	
	54.0	10.880	10.724	*10.625	
	60.0	10.772	10.616	*10.625	
13.375	54.5	12.615	12.459	12.25	6.625 API Regular
	61.0	12.515	12.359	12.25	
	68.0	12.415	12.259	12.25	
	72.0	12.347	12.191	12.00	
16.00	65.0	15.250	15.062	15.00	6.625 API Regular
	75.0	15.125	14.938	14.75	
	84.0	15.010	14.822	14.75	
20.00	94.0	19.124	18.936	17.50	6.625 API Regular

** 5.5 API regular thread optional*

Drillpipe and Tool Joint Condition: Color Code ID

Tool Joint and Drillpipe *Classification*	*Number / Color of Bands*
Premium class	Two white
Class 1	One white
Class 2	One yellow
Class 3	One blue
Class 4	One green
Scrap	One red
Tool Joint Condition	*Number / Color of Stripes*
Field repairable	Three green, 120' apart
Scrap or shop repairable	Three red, 120' apart

Pump Discharge Fluid Volumes
Hydraulic Discharge Hydraulic Volumes



Source: Hughes Christensen

Strength of Drillpipe and Drill Tubing in psi

Drillpipe O.D. (in.)	Weight (lb_m/ft)	Grade	Burst	Collapse	Tensile
2.375	4.70	N-80	11,200	9,800	104,340
	4.85	E	10,580	8,830	97,820
	6.65	D	11,350	10,140	101,000
	6.65	E	15,470	12,480	138,000
2.875	6.50	N-80	10,570	8,900	144,960
	6.85	E	9,980	8,830	135,900
	10.40	D	12,120	10,730	157,000
	10.40	E	16,530	13,210	214,000
3.50	9.30	N-80	10,160	8,580	207,220
	9.50	E	9,600	8,080	194,270
	13.30	D	10,120	9,170	199,000
	13.30	E	12,350	11,290	272,000
4.00	11.00	N-80	9,170	7,520	246,140
	11.85	E	8,660	7,080	230,760
	14.00	D	7,940	7,380	209,000
	14.00	E	10,830	9,090	285,000
4.50	12.75	N-80	8,440	6,680	288,040
	13.75	E	7,900	6,290	270,030
	16.60	D	7,210	6,760	242,000
	16.60	E	9,830	8,310	331,000
5.00	15.00	E	7,830	6,140	328,070
	19.50	D	6,960	6,550	290,000
	19.50	E	9,500	8,060	390,000

Surface Connection Combinations: Component Length-I.D.

Case No.	Stand	Hose	Swivel	Kelly
1	40' - 3.0"	45' - 2.0"	20' - 2.0"	40' - 2.25"
2	40' - 3.5"	55' - 2.5"	25' - 2.5"	40' - 3.25"
3	45' - 4.0"	55' - 3.0"	25' - 2.5"	40' - 3.25"
4	45' - 4.0"	55' - 3.0"	30' - 3.0"	40' - 4.00"

Salt Tables

The following salt tables came from three sources. The potassium chloride table is from the *CRC Handbook of Chemistry and Physics*, 62nd edition. The sodium chloride table is from Staples and Nuttall, *Journal of Physical Chemistry Reference Data*, 1977, Volume 6. The calcium chloride table is from Clarke and Grew, *Journal of Physical Chemistry Reference Data*, 1985, Volume 14. The tables are divided into the following columns.

1. **Percent Wt** = the anhydrous solute weight percent, g solute/l00 g solution.
2. **Specific Gravity** = the ratio of the density of a body to the density of an equal volume of water at 4°C. Specific Gravity is dimensionless.
3. **Density** = the ratio of the mass of a sample to its volume at the same temperature. The density of water is assumed to be 8.33 lb_m/gal.
4. **lb_m of salt/bbl of solution** = the pounds of salt in a barrel solution of the given density.
5. **Gallons of water per barrel of solution** = the gallons of water to make up one barrel of solution of the given density.
6. **Salt**, mg/L = the concentration of salt in 1 liter (L) of solution.
7. **Chlorides**, mg/L = concentration of chlorides in 1 liter (L) of solution.
8. **Volume Increase Factor** = the volume increase that will occur when the specified weight of salt is added to the specified volume of freshwater. The value in table column **8a** is used for retort corrections.
9. **Crystallization Point**, °F = the crystallization point of a solution containing the specified concentration of salt.
10. **A_W** = the activity of the solution. This value has also been called Formation Activity Coefficient (F.A.C.) in previous manuals. This value, regardless of the term applied to it, is a measure of the fluid's potential to absorb water. (See Chapter 3, **Oil- and Synthetic-Base Drilling Fluids**.)

Physical Properties of Potassium Chloride Solutions

Physical Properties of Potassium Chloride Solutions (at 20°C)

1 Percent Wt	2 Specific Gravity	3 Density (lb_m/gal)	4 KCl (lb_m/bbl)	5 H_2O (gal/bbl)	6 KCl (mg/L)	7 Chlorides (mg/L)	8* Vol. Incr. Factor	9 Crystallization Point (T)
1.0	1.005	8.37	3.5	41.8	10,000	4,756	1.005	31.2
2.0	1.011	8.42	7.1	41.6	20,200	9,606	1.009	30.3
3.0	1.017	8.47	10.7	41.4	30,500	14,506	1.013	29.5
4.0	1.024	8.53	14.4	41.3	41,000	19,499	1.017	28.6
5.0	1.030	8.59	18.1	51.1	51,500	24,493	1.022	27.8
6.0	1.037	8.64	21.8	40.9	62,200	29,582	1.026	26.9
7.0	1.044	8.69	25.6	40.7	73,000	34,718	1.031	26.1
8.0	1.050	8.75	29.4	40.5	84,000	39,950	1.035	25.2
9.0	1.057	8.80	33.3	40.4	95,100	45,229	1.039	24.3
10.0	1.063	8.86	37.3	40.2	106,300	50,556	1.045	23.4
11.0	1.070	8.90	41.2	40.0	117,700	55,977	1.050	22.4
12.0	1.077	8.97	45.3	39.8	129,200	61,447	1.055	21.4
13.0	1.084	9.03	49.4	39.6	140,900	67,011	1.061	20.4
14.0	1.091	9.08	53.5	39.4	152,700	72,623	1.066	20.0
15.0	1.097	9.12	57.6	39.1	164,600	78,282	1.072	18.5
16.0	1.104	9.20	61.9	38.9	176,700	84,038	1.078	17.0
17.0	1.111	9.26	66.1	38.7	188,900	89,840	1.084	16.0
18.0	1.119	9.32	70.5	38.5	201,300	95,737	1.090	15.0
19.0	1.126	9.38	74.9	38.3	213,900	101,730	1.097	14.0
20.0	1.111	9.44	79.3	38.0	226,600	107,770	1.104	13.0

** Sacked KCl contains a trivial amount of water, therefore, the vol. increase from sack additions is the same as the retort correction factor.*

Physical Properties of Potassium Chloride Solutions (at 20°C) (continued)

1 Percent Wt	2 Specific Gravity	3 Density (lb_m/gal)	4 KCl (lb_m/bbl)	5 H_2O (gal/bbl)	6 KCl (mg/L)	7 Chlorides (mg/L)	8 Vol. Incr. Factor	9 Crystallization Point (T)
21.0	1.140	9.51	83.9	37.8	239,500	114,000	1.111	22.0
22.0	1.147	9.56	88.4	37.6	252,400	120,040	1.117	34.0
23.0	1.155	9.64	93.1	37.4	265,700	126,473	1.125	48.0
24.0	1.162	9.68	97.7	37.1	278,900	132,643	1.132	59.0

METRIC CONVERSIONS:

KCl (g/L) = KCl (lb_m/bbl) × 2.85714

H_2O (ml/L) = H_2O (gal/bbl) × 23.8086

KCl (ppm) = % wt × 10,000

mg/L = ppm × specific gravity

Cl^-(mg/L) = KCl (mg/L) × 0.476

KCl (mg/L) = Cl^- (mg/L) × 2.1 01

K^+(mg/L) = Cl^- (mg/L) × 1.103

Cl^-(mg/L) = K^+ (mg/L) × 0.907

FORMULAS:

Salt (lb_m/bbl water) = Vol. increase factor × Kl (lb_m/bbl)

Specific gravity = 1.00056 +1.22832 (10^{-6}) (Cl^-, mg/L)

Volume increase factor = 1 + (2.775 × 10 7) $(Cl^-)^{1.105}$

Physical Properties of Potassium Carbonate Solutions

Wt %	S.G. (20°C)	Density lb/gal	K_2CO_3 mg/L	K+ mg/L	$CO^{3=}$	K_2CO_3 lb/bbl	Water gal/bbl
1	1.01	8.42	10,100	5,715	4,386	3.535	41.88
2	1.02	8.49	20,300	11,487	8,815	7.105	41.83
3	1.03	8.57	30,800	17,429	13,374	10.78	41.77
4	1.04	8.64	41,400	23,427	17,977	14.49	41.71
5	1.05	8.72	52,200	29,539	22,667	18.27	41.64
6	1.05	8.80	63,200	35,763	27,443	22.12	41.57
7	1.06	8.87	74,300	42,045	32,263	26.005	41.49
8	1.07	8.95	85,700	48,496	37,213	29.995	41.40
9	1.08	9.03	97,300	55,060	42,250	34.055	41.31
10	1.09	9.11	109,000	61,680	47,331	38.15	41.22
11	1.10	9.19	121,000	68,471	52,541	42.35	41.12
12	1.11	9.27	133,200	75,375	57,839	46.62	41.01
13	1.12	9.35	145,500	82,335	63,180	50.925	40.90
14	1.13	9.43	158,100	89,465	68,651	55.335	40.79
15	1.14	9.52	170,900	96,708	74,209	59.815	40.66
16	1.15	9.60	183,800	104,008	79,811	64.33	40.54
17	1.16	9.68	197,000	111,477	85,542	68.95	40.41
18	1.17	9.77	210,500	119,117	91,405	73.675	40.27
19	1.18	9.85	224,100	126,813	97,310	78.435	40.13
20	1.19	9.94	238,000	134,678	103,346	83.3	39.98
22	1.21	10.11	266,300	150,693	115,634	93.205	39.66
24	1.23	10.29	295,700	167,329	128,401	103.495	39.32
26	1.26	10.47	325,900	184,419	141,514	114.065	38.96
28	1.28	10.66	357,100	202,074	155,062	124.985	38.57
30	1.30	10.84	389,400	220,352	169,088	136.29	38.16
32	1.32	11.03	422,600	239,139	183,504	147.91	37.71
34	1.35	11.22	456,800	258,492	198,354	159.88	37.24
36	1.37	11.42	492,000	278,411	213,639	172.2	36.74
38	1.39	11.62	528,300	298,952	229,401	184.905	36.20
40	1.42	11.81	565,600	320,059	245,598	197.96	35.63

Physical Properties of Sodium Chloride Solutions

Physical Properties of Sodium Chloride Solutions (at 20°C)

1 % Wt	2 Specific Gravity	3 Density (lb_m/gal)	4 NaCl (lb_m/bbl)	5 H_2O (gal/bbl)	6 NaCl (mg/L)	7 Chlorides (mg/L)	8 Vol. Incr. Factor	9 Crystallization Point (T)	10 A_w
1.0	1.007	8.40	3.5	41.87	10,070	6,108	1.003	31.0	0.996
2.0	1.014	8.46	7.1	41.75	20,286	12,305	1.006	30.0	0.989
3.0	1.021	8.52	10.7	41.63	30,630	18,580	1.009	28.8	0.983
4.0	1.029	8.58	14.4	41.46	41,144	24,957	1.013	27.7	0.976
5.0	1.036	8.65	18.2	41.34	51,800	31,421	1.016	26.5	0.970
6.0	1.043	8.70	21.9	41.10	62,586	37,963	1.020	25.3	0.964
7.0	1.050	8.76	25.8	41.02	73,500	44,584	1.024	24.1	0.957
8.0	1.058	8.83	29.7	40.86	84,624	51,331	1.028	22.9	0.950
9.0	1.065	8.89	33.6	40.70	95,850	58,141	1.032	21.5	0.943
10.0	1.073	8.95	37.6	40.54	107,260	65,062	1.036	20.2	0.935
11.0	1.080	9.01	41.6	40.38	118,800	72,062	1.040	18.8	0.927
12.0	1.088	9.08	45.7	40.19	130,512	79,166	1.045	17.3	0.919
13.0	1.095	9.14	49.9	40.00	142,350	86,347	1.050	15.7	0.910
14.0	1.103	9.20	54.1	39.85	154,392	93,651	1.054	14.1	0.901
15.0	1.111	9.27	58.4	39.66	166,650	101,087	1.059	12.4	0.892
16.0	1.118	9.33	62.7	39.44	178,912	108,524	1.065	10.6	0.882
17.0	1.126	9.40	67.1	39.25	191,420	116,112	1.070	8.7	0.872
18.0	1.134	9.46	71.5	39.03	204,102	123,804	1.076	6.7	0.861
19.0	1.142	9.53	76.0	38.85	216,980	131,616	1.081	4.6	0.850
20.0	1.150	9.60	80.6	38.64	229,960	139,489	1.087	2.4	0.839

Physical Properties of Sodium Chloride Solutions (at 20°C) (continued)

1 % Wt	2 Specific Gravity	3 Density (lb_m/gal)	4 NaCl (lb_m/bbl)	5 H_2O (gal/bbl)	6 NaCl (mg/L)	7 Chlorides (mg/L)	8* Vol. Incr. Factor	9 Crystallization Point (T)	10 A_w
21.0	1.158	9.66	85.2	38.43	243,180	147,508	1.09	0.0	0.827
22.0	1.166	9.73	89.9	38.22	256,520	155,600	1.099	–2.5	0.815
23.0	1.174	9.80	94.6	37.97	270,020	163,789	1.106	–5.2	0.802
24.0	1.183	9.87	99.5	37.74	283,800	172,147	1.113	+11.4	0.788
25.0	1.191	9.94	104.4	37.50	297,750	180,609	1.120	+15.0	0.774
26.0	1.199	10.01	109.3	37.27	311,818	189,143	1.127	+25.0	0.759

METRIC CONVERSIONS:

NaCl (g/L) = NaCl (lbm/ft) × 2.85714

H2O (ml/L) = H2O (gal/bbl) × 23.8086

NaCl (ppm) = % wt × 10,000

Cl– (mg/L) = NaCl (mg/L) × 0.6066

NaCl (mg/L) = Cl– (mg/L) × 1.65

mg/L = ppm × specific gravity

FORMULAS:

Salt (lb_m/bbl water) = Volume increase factor × NaCl (lb_m/bbl)

Specific gravity = $1.0036\,[0.99707 + 6.504\,(10^{-3})(\%\text{ wt NaCl}) + 4.395(10^{-5})(\%\text{ wt NaCl})^2]$ ***or*** $1 + 1.94(10^{-6})(\text{Cl}^-, \text{mg/L})^{0.95}$

Volume increase factor = $1.00045 + 2.72232(10^{-3})(\%\text{ wt NaCl}) + 8.15591(10^{-5})(\%\text{ wt NaCl})^2$ ***or*** $1 + 5.88\,(10^{-8})(\text{Cl}^-, \text{mg/L})^{1.2}$

$A_w = 0.99755 - 4.3547(10^{-3})(\%\text{ wt NaCl}) - 1.8205(10^{-4})(\%\text{ wt NaCl})^2$

Properties of Magnesium Chloride Solutions

Properties of Magnesium Chloride Solutions at 20°C —›

Percent Wt	Specific Gravity	Density (lb_m/gal)	$MgCl_2 \cdot 6H_20$ (lb_m/bbl)	H_2O (gal/bbl)
1.0	1.008	8.41	7.54	41.71
2.0	1.016	8.48	15.15	41.45
3.0	1.024	8.55	22.92	40.87
4.0	1.033	8.62	30.76	40.28
5.0	1.041	8.69	38.82	39.69
6.0	1.050	8.76	46.96	39.06
7.0	1.058	8.83	55.24	38.43
8.0	1.067	8.90	63.60	37.80
9.0	1.076	8.98	72.11	37.17
10.0	1.085	9.05	80.85	36.50
11.0	1.094	9.13	89.73	36.16
12.0	1.103	9.20	98.61	35.83
13.0	1.112	9.28	107.76	35.13
14.0	1.121	9.35	116.90	34.44
15.0	1.130	9.43	126.35	33.73
16.0	1.139	9.50	135.79	33.01
17.0	1.148	9.58	145.53	31.48
18.0	1.157	9.66	155.27	29.95
19.0	1.167	9.73	165.28	29.13
20.0	1.176	9.81	175.28	28.31
21.0	1.186	9.90	185.66	27.47
22.0	1.196	9.98	196.03	26.63
23.0	1.206	10.06	206.78	25.77
24.0	1.216	10.15	217.53	24.91
25.0	1.227	10.24	228.58	24.00
26.0	1.237	10.32	239.63	23.10
27.0	1.248	10.41	251.02	22.18
28.0	1.258	10.50	262.40	21.25
29.0	1.269	10.59	274.12	20.29
30.0	1.279	10.67	285.84	19.32

FORMULAS:

Salt (lb_m/bbl water) = Volume increase factor × $MgCl_2$ (lb_m/bbl)

S.G. = $1.00038 + 7.95497(10^{-3})(\%\ \text{Wt}\ MgCl_2) + 4.38583(10^{-5})(\%\ \text{Wt}\ MgCl_2)^2$

*__Volume increase factor__ =

$$0.999074 + 1.58008(10^{-3})(\%\ \text{Wt}\ MgCl_2) + 7.66303(10^{-5})(\%\ \text{Wt}\ MgCl_2)^2$$

$\mathbf{A_w} = 0.986688 - 1.2334\ (10^{-3})(\%\ \text{Wt}\ MgCl_2) - 4.16512\ (10^{-4})(\%\ \text{Wt}\ MgCl_2\ )^2$

Properties of Magnesium Chloride Solutions at 20°C (continued)

$MgCl_2$ (mg/L)	Chlorides (mg/L)	Vol.* Incr. Fac. 100% $MgCl_2$	Vol.** Incr. Fac. from Salt	A_W
10,080	7,502	1.001	1.007	0.985
20,320	15,123	1.002	1.013	0.981
30,720	22,863	1.004	1.028	0.978
41,320	30,752	1.006	1.043	0.974
52,050	38,738	1.009	1.058	0.970
63,000	46,887	1.012	1.075	0.964
74,060	55,118	1.014	1.093	0.958
85,360	63,528	1.017	1.111	0.952
96,840	72,072	1.020	1.130	0.943
108,500	80,750	1.023	1.151	0.934
120,340	89,562	1.026	1.161	0.924
132,360	98,508	1.029	1.172	0.913
144,560	107,587	1.033	1.195	0.901
156,940	116,801	1.036	1.220	0.888
169,500	126,149	1.040	1.245	0.875
182,240	135,630	1.044	1.272	0.862
195,160	145,246	1.048	1.334	0.846
208,260	154,995	1.052	1.403	0.830
221,635	164,950	1.057	1.442	0.813
235,200	175,045	1.061	1.484	0.795
249,060	185,360	1.066	1.529	0.778
263,120	195,824	1.071	1.577	0.760
277,380	206,437	1.076	1.630	0.737
291,840	217,199	1.081	1.686	0.713
306,625	228,203	1.087	1.750	0.691
321,620	239,362	1.092	1.818	0.669
336,825	250,679	1.098	1.894	0.647
352,240	262,151	1.103	1.976	0.625
367,865	273,780	1.110	2.070	0.604
383,700	285,565	1.116	2.174	0.582

* Volume increase from 100% salt, i.e., from retort.

** Volume increase from salt and water in sacked salt.

METRIC CONVERSIONS:

$MgCl_2$ (g/L) = $MgCl_2$ (lb_m/bbl) × 2.85714

H_2O (mL/L) = H_2O (gal/bbl) × 23.8086

$MgCl_2$ (ppm) = % Wt $MgCl_2$ × 10,000

Cl^- (ppm) = $MgCl_2$ (ppm) × 0.7442

Properties of Calcium Chloride Solutions

Properties of Calcium Chloride Solutions at 20°C —›

1 % Wt	2 Specific Gravity	3 Density (lb$_m$/gal)	4a 100% $CaCl_2$ (lb$_m$/bbl)	4b 95% $CaCl_2$ (lb$_m$/bbl)	5a H_20 Using 100% $CaCl_2$ (gal/bbl)	5b H_20 Using 95% $CaCl_2$ (gal/bbl)
1	1.009	8.42	3.53	3.72	41.93	41.91
2	1.017	8.49	7.13	7.50	41.85	41.81
3	1.026	8.56	10.78	11.35	41.78	41.71
4	1.034	8.63	14.50	15.26	41.69	41.60
5	1.043	8.70	18.27	19.23	41.60	41.48
6	1.051	8.77	22.11	23.27	41.49	41.35
7	1.060	8.84	25.99	27.36	41.38	41.22
8	1.068	8.91	29.94	31.52	41.27	41.08
9	1.077	8.98	33.95	35.74	41.14	40.93
10	1.085	9.05	38.03	40.03	41.01	40.77
11	1.094	9.13	42.18	44.40	40.90	40.63
12	1.103	9.20	46.39	48.83	40.76	40.47
13	1.113	9.28	50.69	53.36	40.65	40.33
14	1.122	9.36	55.05	57.95	40.53	40.18
15	1.132	9.44	59.49	62.62	40.40	40.02
16	1.141	9.52	63.98	67.35	40.25	39.85
17	1.151	9.60	68.55	72.16	40.10	39.67
18	1.160	9.68	73.18	77.03	39.95	39.49
19	1.170	9.76	77.91	82.01	39.80	39.31
20	1.180	9.85	82.72	87.07	39.65	39.13
21	1.190	9.93	87.59	92.20	39.48	38.93
22	1.200	10.01	92.53	97.40	39.31	38.73
23	1.210	10.10	97.55	102.68	39.14	38.52
24	1.220	10.18	102.62	108.02	38.95	38.30
25	1.231	10.27	107.82	113.49	38.76	38.08
26	1.241	10.36	113.09	119.04	38.57	37.86
27	1.252	10.44	118.44	124.67	38.37	37.62
28	1.262	10.53	123.85	130.37	38.16	37.38
29	1.273	10.62	129.39	136.20	37.96	37.14
30	1.284	10.71	135.00	142.11	37.75	36.90
31	1.295	10.81	140.70	148.11	37.53	36.64
32	1.306	10.90	146.48	154.19	37.30	36.38
33	1.317	10.99	152.32	160.34	37.06	36.10
34	1.328	11.08	158.25	166.58	36.81	35.81
35	1.340	11.18	164.32	172.97	36.57	35.53
36	1.351	11.27	170.47	179.44	36.32	35.24
37	1.363	11.37	176.76	186.06	36.06	34.95
38	1.375	11.47	183.13	192.77	35.81	34.65
39	1.387	11.57	189.53	199.50	35.53	34.33
40	1.398	11.67	195.99	206.31	35.23	33.99

Properties of Calcium Chloride Solutions at 20°C (continued)

6 $CaCl_2$ (mg/L)	7 Chlorides (mg/L)	8a* Volume Increase Factor 100% $CaCl_2$	8b** Volume Increase Factor 95% $CaCl_2$	9 Crystallization Point (°F)	10 A_w
10,085	6,454	1.002	1.002	31.1	0.998
20,340	13,018	1.004	1.004	30.4	0.996
30,765	19,690	1.006	1.007	29.5	0.993
41,360	26,470	1.008	1.010	28.6	0.989
52,125	33,360	1.011	1.013	27.7	0.984
63,060	40,358	1.013	1.016	26.8	0.979
74,165	47,466	1.016	1.019	25.9	0.973
85,440	54,682	1.018	1.022	24.6	0.967
96,885	62,006	1.021	1.026	23.5	0.959
108,500	69,440	1.024	1.030	22.3	0.951
120,340	77,018	1.027	1.034	20.8	0.942
132,360	84,710	1.030	1.038	19.3	0.933
144,625	92,560	1.034	1.041	17.6	0.923
157,080	100,531	1.037	1.045	15.5	0.912
169,725	108,624	1.041	1.049	13.5	0.900
182,560	116,838	1.044	1.054	11.2	0.888
195,585	125,174	1.048	1.059	8.6	0.875
208,800	133,632	1.051	1.064	5.9	0.862
222,300	142,272	1.056	1.068	2.8	0.847
236,000	151,040	1.060	1.073	–0.4	0.832
249,900	159,936	1.065	1.079	–3.9	0.816
264,000	168,960	1.069	1.084	–7.8	0.800
278,300	178,112	1.074	1.090	–11.9	0.783
292,800	187,392	1.078	1.097	–16.2	0.765
307,625	196,880	1.084	1.103	–21.0	0.746
322,660	206,502	1.089	1.109	–25.8	0.727
337,905	216,259	1.095	1.116	–31.2	0.707
353,360	226,150	1.100	1.124	–37.8	0.686
369,170	236,269	1.107	1.131	–49.4	0.665
385,200	246,528	1.113	1.138	–50.8	0.643
401,450	256,928	1.120	1.146	–33.2	0.620
417,920	267,469	1.126	1.155	–19.5	0.597
434,610	278,150	1.134	1.163	–6.9	0.573
451,520	288,973	1.141	1.173	+4.3	0.548
468,825	300,048	1.149	1.182	+14.4	0.522
486,360	311,270	1.156	1.192	+24.1	0.496
504,310	322,758	1.165	1.202	+33.4	0.469
522,500	334,400	1.173	1.212	+42.1	0.441
540,735	346,070	1.183	1.224	+49.6	0.413
559,200	357,888	1.192	1.236	+55.9	0.384

Properties of Calcium Chloride Solutions (at 20°C)

- *When Using $CaCl_2$ with purity other than 95%:*

New $CaCl_2$ (lb_m/bbl) = 95 × 95% $CaCl_2$ (lb_m/bbl) ÷ % Purity

$$\underset{(gal/bbl)}{\text{New } H_2O} = \underset{(gal/bbl)}{H_2O} - \left[\frac{\text{New } CaCl_2\ (lb_m/bbl) - 95\%\ CaCl_2\ (lb_m/bbl)}{8.345}\right]$$

Volume increase from salt = 42 ÷ New water

- *Example: 35% $CaCl_2$ brine using 78% $CaCl_2$:*

New $CaCl_2$ (lb_m/bbl) = 95 × 172.97 ÷ 78 = 210.67

$$\text{New } H_2O\ (lb_m/bbl) = 35.53 - \left[\frac{210.67 - 172.97}{8.345}\right] = 31.01$$

Volume increase from 78% salt = 42 ÷ 31.01 = 1.354

- *Metric Conversions:*

$CaCl_2$ (g/L) = $CaCl_2$ (lb_m/bbl) × 2.85714

H_2O (mL/L) = H_2O (gal/bbl) × 23.8086

$CaCl_2$ (ppm) = % Wt × 10,000

Cl^- (ppm) = $CaCl_2$ (ppm) × 0.639

mg/L = ppm × specific gravity (S.G.)

- *Formulas:*

Salt (lb_m/bbl water) = Volume incr. factor × $CaCl_2$ (lb_m/bbl)

$$\textbf{S.G.} = 1.0036\,[0.99707 + 7.923\,(10^{-3})\,(\%\text{ wt } CaCl_2) + 4.964(10^{-5})\,(\%\text{ wt } CaCl_2)^2] + 8.94922(10^{-5})\,(\%\text{ wt } CaCl_2)^2$$

$$\mathbf{A_w} = 0.99989 - 1.39359\,(10^{-3})\,(\%\text{ wt } CaCl_2) - 3.50352\,(10^{-4})\,(\%\text{ wt } CaCl_2)^2$$

$$\%\text{ wt } CaCl_2 = \frac{100\%\ CaCl_2\ (lb_m/bbl) \times \%\text{ Purity } CaCl_2}{\text{Specific Gravity} \times 350}$$

Physical Properties of Ammonium Chloride Solutions

Density lb/gal	Specific Gravity @ 60°F	lbs NH_4Cl per bbl Brine	bbls Water per bbl Brine	% Weight Ammonium Chloride (NH_4Cl)
8.4	1.007	7.0	0.990	1.98
8.45	1.013	10.5	0.981	3.00
8.5	1.020	19.0	0.969	5.30
8.6	1.031	30.0	0.940	8.40
8.7	1.044	42.0	0.919	11.50
8.8	1.055	53.0	0.900	14.40
8.9	1.068	65.0	0.881	17.40
9.0	1.079	77.0	0.860	20.40
9.1	1.128	88.0	0.840	23.00
9.2	1.103	100.0	0.819	25.90
9.5	1.139	135.0	0.750	33.90

Preparation of Calcium Chloride Solutions

Preparation of Calcium Chloride ($CaCl_2$) Solutions Using Liquid 11.6 lb/gal $CaCl_2$

Ve* 10^4	Density lb/gal	Specific Gravity @ 68°F	bbl 11.6 $CaCl_2$ per bbl Brine	bbl Water per bbl Brine	Chrystallization Point, °F	Weight % $CaCl_2$
	8.4	1.01	0.022	0.978	+31	1.0
	8.5	1.02	0.052	0.948	+30	2.0
	8.6	1.03	0.083	0.917	+28	4.0
	8.7	1.04	0.113	0.887	+27	5.0
	8.8	1.06	0.144	0.856	+25	6.0
	8.9	1.07	0.174	0.826	+23	7.0
3.33	9.0	1.08	0.203	0.797	+21	9.0
	9.1	1.09	0.233	0.767	+19	10.0
	9.2	1.10	0.264	0.736	+17	11.0
	9.3	1.11	0.294	0.706	+15	12.0
	9.4	1.13	0.325	0.675	+12	14.0
3.00	9.5	1.14	0.356	0.644	+9	15.0
	9.6	1.15	0.390	0.610	+6	16.0
	9.7	1.16	0.420	0.580	+3	17.0
	9.8	1.17	0.450	0.550	–1	19.0
	9.9	1.19	0.480	0.520	–6	20.0

Preparation of Calcium Chloride ($CaCl_2$) Solutions Using Liquid 11.6 lb/gal $CaCl_2$ (continued)

Ve* 10^4	Density lb/gal	Specific Gravity @ 68°F	bbl 11.6 $CaCl_2$ per bbl Brine	bbl Water per bbl Brine	Chrystallization Point, °F	Weight % $CaCl_2$
2.89	10.0	1.20	0.510	0.490	–11	21.0
	10.1	1.21	0.540	0.460	–16	22.0
	10.2	1.22	0.571	0.429	–22	23.0
	10.3	1.23	0.601	0.399	–28	25.0
	10.4	1.25	0.632	0.368	–34	26.0
2.6	10.5	1.26	0.663	0.337	–41	27.0
	10.6	1.27	0.694	0.306	–48	28.0
	10.7	1.28	0.724	0.276	–55	29.0
	10.8	1.29	0.755	0.245	–51	30.0
	10.9	1.31	0.785	0.215	–31	31.0
2.4	11.0	1.32	0.820	0.180	–15	32.0
	11.1	1.33	0.850	0.150	0	33.0
	11.2	1.34	0.880	0.120	+12	34.0
	11.3	1.35	0.910	0.090	+23	35.0
	11.4	1.37	0.940	0.060	+34	36.0
2.39	11.5	1.38	0.970	0.030	+43	37.0
	11.6	1.39	1.00	0.000	+53	38.0

* *Determined by ASTM methods*

Ve = expansion factor gal/gal/°F; used with density adjustment calculations.

Example: To prepare 10 bbl of 11.0 lb/gal $CaCl_2$ from 11.6 lb/gal liquid $CaCl_2$:
Add 10 × 0.264 = 2.6 bbl of 11.6 lb/gal $CaCl_2$ to 10 × 0.736 bbl of fresh water.

Preparation of Potassium Bromide-Base Solutions Using Granular Concentrated KBr

Density lb/gal	bbl Water per bbl Brine	bbl KBr per bbl Brine	% KBr	Crystallization Point, °F (LCTD)
8.3	1.000	–	–	32
8.6	0.985	15.1	4.2	30
8.7	0.980	21.9	6.0	30
8.8	0.974	28.1	7.6	29
8.9	0.967	34.8	9.3	28
9.0	0.962	40.8	10.8	27
9.1	0.956	47.0	12.3	27
9.2	0.954	52.6	13.6	26
9.3	0.947	58.6	15.0	26
9.4	0.942	64.7	16.4	25
9.5	0.937	70.6	17.7	24
9.6	0.932	76.6	19.0	23
9.7	0.928	82.3	20.2	22
9.8	0.922	88.5	21.5	22
9.9	0.916	94.8	22.8	21
10.0	0.911	100.8	24.0	19
10.1	0.905	106.9	25.2	18
10.2	0.901	112.7	26.3	17
10.3	0.895	119.0	27.5	16
10.4	0.888	125.4	28.7	15
10.5	0.883	131.4	29.8	14
10.6	0.878	137.6	30.9	12
10.7	0.872	143.8	32.0	13
10.8	0.865	150.6	33.2	20
10.9	0.858	157.0	34.3	27
11.0	0.854	162.6	35.2	33
11.1	0.847	169.2	36.3	41
11.2	0.842	175.5	37.3	49
11.3	0.835	181.2	38.3	57
11.4	0.829	188.2	39.3	66
11.5	0.824	194.2	40.2	75

Example:
To prepare 10 bbl of 10 lb/gal KBr:
10 × 0.911 = 9.1 bbl water; 10 × 100.8 = 1,008 lbs KBr
Add 1,008 lbs KBr to 9.1 bbl water.

Calcium-Chloride / Calcium-Bromide Solution Requirements Using 11.6 lb_m/gal $CaCl_2$ Brine, 14.2 lb_m/gal $CaBr_2$ Brine, and Sacked $CaCl_2$

(Formulation per 1 bbl)

Brine Density at 60°F (lb_m/gal)	11.6 lb_m/gal $CaCl_2$ (bbl)	14.2 lb_m/gal $CaBr_2$ (bbl)	94 to 97% $CaCl_2$ (lb) (Flakes or Pellets)	Crystallization Point (°F)
11.7	.9714	.0246	3.5	+45
11.8	.9429	.9429	6.9	+51
11.9	.9143	.0738	10.4	+52
12.0	.8857	.0984	13.9	+54
12.1	.8572	.1229	17.4	+55
12.2	.8286	.1475	20.8	+55
12.3	.8000	.1722	24.3	+56
12.4	.7715	.1967	27.8	+56
12.5	.7429	.2213	31.2	+57
12.6	.7143	.2459	34.7	+58
12.7	.6857	.2705	38.2	+58
12.8	.6572	.2951	41.7	+58
12.9	.6286	.3197	45.1	+59
13.0	.6000	.3443	48.6	+59
13.1	.5714	.3689	52.1	+60
13.2	.5429	.3935	55.5	+60
13.3	.5143	.4181	59.0	+60
13.4	.4851	.4432	62.6	+61
13.5	.4572	.4672	66.0	+61
13.6	.4286	4919	69.4	+62
13.7	.4000	.5165	72.9	+62
13.8	.3714	.5411	75.4	+63
13.9	.3429	.5656	79.8	+63

Calcium-Chloride / Calcium-Bromide Solution Requirements (continued)

Brine Density at 60°F (lb_m/gal)	11.6 lb_m/gal $CaCl_2$ (bbl)	14.2 lb_m/gal $CaBr_2$ (bbl)	94 to 97% $CaCl_2$ (lb) (Flakes or Pellets)	Crystallization Point (°F)
14.0	.3143	.5903	83.3	+64
14.1	.2857	.6149	86.8	+64
14.2	.2572	.6394	90.3	+64
14.3	.2286	.6640	93.7	+65
14.4	2000	.6886	97.2	+65
14.5	.1715	.7132	100.7	+65
14.6	.1429	.7378	104.2	+66
14.7	.1143	.7624	107.6	+66
14.8	.0858	.7869	111.1	+67
14.9	.0572	.8116	114.6	+67
15.0	.0286	.8361	118.0	+67
15.1	.0000	.8608	121.5	+68

Conversions

$$ppm\ CaCl_2 = \%\ wt \times 10,000$$

$$ppm\ Cl^- = PPM\ CaCl_2 \times .64$$

Formulas

When using 78% $CaCl_2$,

$$(lb_m/bbl) = 95\%\ CaCl_2 \times 1.218$$

$$\frac{New\ H_2O}{(gal/bbl)} = \frac{H_2O}{(gal/bbl)} - \left[\frac{\frac{78\%\ CaCl_2}{(lb_m/bbl)} - \frac{95\%\ CaCl_2}{(lb_m/bbl)}}{8.345}\right]$$

Preparation of Calcium Bromide-Base Solutions Using Solid 94% $CaCl_2$ and Liquid 14.2 lb/gal $CaBr_2$

$CaCl_2$ / $CaBr_2$ Density at 60°F		lb $CaCl_2$ per bbl Brine	bbl 14.2 $CaBr_2$ per bbl Brine	bbl Fresh Water per bbl Brine
lb/gal	lb/ft^3			
11.7	87.52	193.39	0.0254	0.8163
11.8	88.26	191.00	0.0507	0.7924
11.9	89.01	188.42	0.0762	0.7683
12.0	89.76	185.85	0.1016	0.7443
12.1	90.51	183.28	0.1269	0.7203
12.2	91.26	180.70	0.1524	0.6963
12.3	92.00	178.13	0.1778	0.6723
12.4	92.75	175.56	0.2032	0.6483
12.5	93.50	172.99	0.2286	0.6243
12.6	94.25	170.41	0.2540	0.6003
12.7	95.00	167.83	0.2794	0.5762
12.8	95.74	165.27	0.3048	0.5523
13.0	97.24	160.12	0.3556	0.5042
13.1	97.99	157.54	0.3810	0.4802
13.2	98.74	154.97	0.4064	0.4562
13.3	99.48	152.40	0.4318	0.4322
13.4	100.23	149.82	0.4572	0.4082
13.5	100.98	147.26	0.4826	0.3842
13.6	101.73	144.68	0.5080	0.3602
13.7	102.48	142.12	0.5334	0.3361
13.8	103.22	139.54	0.5589	0.3121
13.9	103.97	136.98	0.5842	0.2882
14.0	104.72	134.40	0.6069	0.2641
14.1	105.47	131.84	0.6351	0.2401
14.2	106.22	129.26	0.6604	0.2161
14.3	106.96	126.68	0.6858	0.1921
14.4	107.71	124.11	0.7113	0.1681
14.5	108.46	121.54	0.7366	0.1441
14.6	109.21	118.97	0.7620	0.1201
14.7	109.96	116.39	0.7875	0.0961
14.8	110.70	113.82	0.8128	0.0721
14.9	111.45	111.25	0.8382	0.0481
15.0	112.20	108.67	0.8637	00.241
15.1	112.95	106.10	0.8891	0.0000

Example:
To prepare 10 bbl of 13.0 lb/gal $CaBr_2$ from minimum 94% solid $CaCl_2$ and 14.2 lb/gal liquid $CaBr_2$: Add 10 × 160.1 = 1600 lbs of solid $CaCl_2$ to 10 × 0.35 = 3.5 bbl of 14.2 lb/gal $CaBr_2$ and 10 × 0.50 = 5.0 bbl of fresh water.

Preparation of Calcium Bromide-Base Solutions Using 95% Dry $CaBr_2$

Brine Density		bbl Fresh Water per bbl Brine	lb 95% $CaBr_2$ per bbl Brine
lb/gal	lb/ft^3		
11.0	82.28	0.889	150.8
11.1	83.03	0.887	155.9
11.2	83.78	0.884	160.9
11.3	84.52	0.878	167.4
11.4	85.27	0.869	174.5
11.5	86.02	0.867	179.6
11.6	86.77	0.864	184.7
11.7	87.52	0.863	188.9
11.8	88.26	0.849	198.3
11.9	89.01	0.849	202.6
12.0	8976	0.848	207.0
12.1	90.51	0.840	214.1
12.3	92.00	0.831	225.8
12.4	92.75	0.830	230.3
12.5	93.50	0.821	237.7
12.6	94.25	0.819	242.4
12.7	95.00	0.810	250.0
12.8	95.74	0.808	254.8
12.9	96.49	0.797	266.5
13.0	97.24	0.796	267.4
13.1	97.99	0.794	272.3
13.2	98.74	0.791	277.3
13.3	99.48	0.789	282.4
13.4	100.23	0.778	290.4
13.5	100.98	0.775	295.6
13.6	101.73	0.772	300.8
13.7	102.48	0.761	309.0
13.8	103.22	0.758	314.3
13.9	103.97	0.755	319.7
14.0	104.72	0.751	325.1
14.1	105.47	0.748	330.5
14.2	106.22	0.744	335.9
14.3	106.96	0.740	341.5

Example:
To prepare 10 bbl of 13.0 lb/gal $CaBr_2$ from 95% solid $CaBr_2$:
Add 10 × 267.4 = 2,675 lbs of 95% $CaBr_2$ to 10 × 0.796 = 7.9 bbl of fresh water.

Preparation of Sodium Bromide-Base Solutions Using 10.0 lb/gal NaCl Solution and 12.4 lb/gal NaBr Solution

Density (lb/gal)	bbl 10.0 NaCl per bbl Brine	bbl 12.4 NaBr per bbl Brine	Crystallization Point (°F) (LCTD)
10.0	1.000	0.000	30
10.1	0.958	0.042	*
10.2	0.917	0.083	*
10.3	0.875	0.125	*
10.4	0.833	0.167	*
10.5	0.792	0.208	*
10.6	0.750	0.250	*
10.7	0.708	0.292	*
10.8	0.667	0.333	*
10.9	0.625	0.375	*
11.1	0.583	0.417	*
11.2	0.500	0.500	*
11.3	0.458	0.542	*
11.4	0.417	0.583	*
11.5	0.375	0.625	*
11.6	0.333	0.667	*
11.7	0.292	0.708	*
11.8	0.250	0.750	*
11.9	0.208	0.792	23
12.0	0.167	0.833	28
12.1	0.125	0.875	32
12.2	0.083	0.917	36
12.3	0.042	0.958	39
12.4	0.000	1.000	46

* *Data being confirmed*

Example:

To prepare 10 bbl of 11.0 lb/gal NaBr:

10 × 0.583 = 5.8 bbl 10.0 lb/gal NaCl

10 × 0.417 = 4.2 bbl 12.4 lb/gal NaBr

Add 5.8 bbl of 10.0 lb/gal NaCl to 4.2 bbl 12.4 lb/gal NaBr.

Preparation of Sodium Bromide-Base Solutions Using Solid NaCl, Granular Concentrated NaBr, and Water

Density lb/gal	bbl Water per bbl Brine	bbl NaCl per bbl Brine	lb NaBr per bbl Brine	Crystallization Point, °F (LCTD)
10.0	0.886	110.0	0	30
10.1	0.883	106.0	9.3	*
10.2	0.880	102.0	18.6	*
10.3	0.877	97.8	27.9	*
10.4	0.874	93.7	37.1	*
10.5	0.871	89.6	46.4	*
10.6	0.868	85.6	55.7	*
10.7	0.865	81.5	65.0	*
10.8	0.862	77.4	74.3	*
10.9	0.859	73.4	83.6	*
11.0	0.856	69.3	92.8	*
11.1	0.853	65.2	102.0	*
11.2	0.850	61.2	111.0	*
11.3	0.847	57.1	121.0	*
11.4	0.844	52.9	130.0	*
11.5	0.841	48.8	139.0	*
11.6	0.838	44.8	149.0	*
11.7	0.835	40.7	158.0	*
11.8	0.832	36.6	167.0	*
11.9	0.829	32.6	177.0	*
12.0	0.826	28.5	186.0	37
12.1	0.823	24.4	195.0	41
12.2	0.820	20.4	204.0	47
12.3	0.818	16.3	214.0	49
12.4	0.815	12.2	223.0	53
12.5	0.812	8.1	232.0	56
12.6	0.809	4.1	242.0	60
12.7	0.806	0	251.0	63

** Data being confirmed*

Example:

To prepare 10 bbl of 11.0 lb/gal NaBr:

10 × 0.856 = 8.6 bbl water

10 × 69.3 = 693 lbs NaCl

10 × 92.8 = 928 lbs NaBr

Add 693 lbs NaCl and 928 lbs NaBr to 8.6 bbl of water.

Sodium Bromide Brine Requirements (using 95% NaBr)

Brine @ 20°C/68°F		Requirements for 1 bbl Brine		Requirements for 1 M^3 of Brine		Crystal Point**	
ppg	S.G.	H_2O gals	NaBr lbs	H_2O/ M^{3}s	NaBr kgs	°F	°C
8.4	1.007	41.81	4.08	0.996	11.65	31.0	– 0.6
8.5	1.019	41.66	9.60	0.992	27.38	30.0	– 1.1
8.6	1.031	41.51	15.07	0.988	42.99	29.0	– 1.7
8.7	1.043	41.35	20.60	0.984	58.77	29.0	– 1.7
8.8	1.055	41.18	26.15	0.981	74.62	28.0	– 2.2
8.9	1.067	41.02	31.70	0.977	90.44	26.0	– 3.3
9.0	1.079	40.85	37.39	0.973	106.68	25.0	– 3.9
9.1	1.091	40.69	42.92	0.969	122.45	24.0	– 4.4
9.2	1.103	40.51	48.55	0.965	138.52	23.0	– 5.0
9.3	1.115	40.34	54.20	0.961	154.64	22.0	– 5.6
9.4	1.127	40.17	59.84	0.956	170.72	21.0	– 6.1
9.5	1.139	39.99	65.52	0.952	186.92	20.0	– 6.7
9.6	1.151	39.81	71.21	0.948	203.15	19.0	– 7.2
9.7	1.163	39.64	76.91	0.944	219.42	18.0	– 7.8
9.8	1.175	39.46	82.58	0.939	235.62	16.0	– 8.9
9.9	1.187	39.27	88.33	0.935	252.01	15.0	– 9.4
10.0	1.199	39.09	94.05	0.931	268.34	14.0	– 10.0
10.1	1.211	38.90	99.81	0.926	284.75	12.0	– 11.1
10.2	1.223	38.72	105.56	0.922	301.18	11.0	– 11.7
10.3	1.235	38.53	111.33	0.917	317.62	10.0	– 12.2
10.4	1.247	38.34	117.09	0.913	334.07	8.0	– 13.3
10.5	1.259	38.16	122.86	0.909	350.52	6.0	– 14.4
10.6	1.271	37.97	128.62	0.904	366.96	5.0	– 15.0
10.7	1.283	37.78	134.41	0.900	383.48	4.0	– 15.6
10.8	1.295	37.59	140.19	0.895	399.98	2.0	– 16.7
10.9	1.307	37.40	146.02	0.890	416.62	0.0	– 17.8

Sodium Bromide Brine Requirements (using 95% NaBr) (continued)

Brine @ 20°C/68°F		Requirements for 1 bbl Brine		Requirements for 1 M^3 of Brine		Crystal Point**	
ppg	S.G.	H_2O gals	NaBr lbs	H_2O/ M^3s	NaBr kgs	°F	°C
11.0	1.319	37.20	151.87	0.886	433.30	– 2.0	– 18.9
11.1	1.331	37.00	157.71	0.881	449.96	– 3.0	– 19.4
11.2	1.343	36.80	163.58	0.876	466.72	– 5.0	– 20.6
11.3	1.354	36.61	169.40	0.872	483.32	– 7.0	– 21.7
11.4	1.366	36.41	175.28	0.867	500.08	– 9.0	– 22.8
11.5	1.379	36.21	181.14	0.862	516.79	– 11.0	– 23.9
11.6	1.391	36.02	186.98	0.858	533.47	– 14.0	– 25.6
11.7	1.402	35.81	192.83	0.853	550.16	– 16.0	– 26.7

***Due to variances in salt impurities and nucleation sites, confirmation of the crystallization point prior to field use is recommended.*

Sodium Formate Brine Table

Sodium Formate Brine Table

HCOONa (Wt%)	HCOONa (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correction Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
1.0	10.05	996.6	1.0049	8.371	1.0034	3397	3.53	0.992
2.0	20.20	991.7	1.0102	8.415	1.0083	6829	7.13	0.986
3.0	30.47	987.0	1.0157	8.461	1.0131	10301	10.81	0.979
4.0	40.86	982.4	1.0215	8.509	1.0179	13813	14.56	0.972
5.0	51.38	977.9	1.0275	8.559	1.0226	17367	18.39	0.965
6.0	62.02	973.4	1.0337	8.611	1.0273	20966	22.30	0.958
7.0	72.80	968.9	1.0400	8.663	1.0321	24609	26.30	0.951
8.0	83.71	964.4	1.0464	8.716	1.0369	28297	30.38	0.946
9.0	94.75	958.8	1.0528	8.770	1.0419	32030	34.55	0.938
10.0	105.83	956.1	1.0593	8.824	1.0470	35808	38.82	0.932
11.0	117.24	950.3	1.0668	8.878	1.0523	39631	43.18	0.925
12.0	128.68	945.4	1.0724	8.933	1.0578	43600	47.64	0.919
13.0	140.26	940.4	1.0789	8.987	1.0634	47413	52.20	0.913
14.0	151.97	935.2	1.0855	9.042	1.0693	51372	56.87	0.906
15.0	163.81	930.0	1.0921	9.097	1.0763	55375	61.65	0.900
16.0	175.79	924.5	1.0987	9.152	1.0816	59424	66.55	0.893

Sodium Formate Brine Table

HCOONa (Wt%)	HCOONa (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correction Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
17.0	187.91	919.1	1.1053	9.207	1.0880	63519	71.56	0.887
18.0	200.16	913.5	1.1120	9.263	1.0947	67660	76.69	0.880
19.0	212.56	907.7	1.1187	9.318	1.1016	71848	81.95	0.873
20.0	226.08	901.9	1.1254	9.374	1.1087	76084	87.34	0.866
21.0	237.75	896.0	1.1322	9.431	1.1160	80369	92.87	0.859
22.0	250.58	890.0	1.1390	9.488	1.1236	84704	98.54	0.852
23.0	253.56	883.9	1.1459	9.546	1.1313	89092	104.36	0.844
24.0	276.69	877.8	1.1529	9.604	1.1392	93532	110.33	0.836
25.0	289.99	871.5	1.1600	9.663	1.1474	98027	116.46	0.828
26.0	303.46	865.2	1.1671	9.722	1.1557	102579	122.75	0.819
27.0	317.09	858.9	1.1744	9.783	1.1643	107188	129.22	0.810
28.0	330.90	852.4	1.1818	9.844	1.1731	111857	135.87	0.800
29.0	344.89	845.9	1.1893	9.907	1.1822	116586	142.70	0.790
30.0	359.08	839.3	1.1969	9.970	1.1914	121376	149.73	0.780
31.0	373.42	832.7	1.2046	10.034	1.2010	126228	156.96	0.770
32.0	387.96	826.9	1.2124	10.099	1.2108	131143	164.41	0.759

Sodium Formate Brine Table

HCOONa (Wt%)	HCOONa (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correction Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
33.0	402.68	819.0	1.2202	10.165	1.2210	136119	172.08	0.748
34.0	417.58	812.1	1.2282	10.231	1.2314	141157	179.98	0.736
35.0	432.66	806.0	1.2362	10.297	1.2423	146253	188.12	0.725
36.0	447.90	797.7	1.2442	10.364	1.2536	151407	196.52	0.713
37.0	463.30	790.3	1.2522	10.431	1.2654	156613	205.19	0.702
38.0	478.85	782.7	1.2601	10.497	1.2776	161868	214.13	0.691
39.0	494.52	774.9	1.2680	10.562	1.2905	167165	223.37	0.680
40.0	510.29	766.8	1.2757	10.627	1.3041	172497	232.91	0.670
41.0	526.14	758.5	1.2833	10.690	1.3184	177855	242.78	0.660
42.0	542.04	749.9	1.2906	10.750	1.3336	183227	252.99	0.651
43.0	557.93	740.9	1.2975	10.808	1.3497	188601	263.56	0.643
44.0	573.79	731.6	1.3041	10.863	1.3669	193962	274.51	0.636
45.0	589.58	721.9	1.3101	10.913	1.3863	199293	286.86	0.630
46.0	605.19	711.7	1.3156	10.959	1.4051	204574	297.61	0.626
47.0	620.59	701.1	1.3204	10.999	1.4264	209782	309.82	0.622
48.0	635.71	689.9	1.3244	11.032	1.4494	214891	322.50	0.619
49.0	650.45	678.2	1.3274	11.058	1.4746	219874	335.67	0.617
49.5	657.65	672.1	1.3286	11.067	1.4878	222307	342.45	0.616

Potassium Formate Brine Table

Potassium Formate Brine Table

HCOOK (Wt%)	HCOOK (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correction Factor	Potassium (mg/L)	lbs HCOOK/ bbl H_2O	Activity
1.0	10.06	998.0	1.0063	8.382	1.0020	4677	3.53	0.994
2.0	20.25	994.0	1.0124	8.433	1.0061	9411	7.13	0.991
3.0	30.55	989.7	1.0164	8.484	1.0106	14201	10.81	0.987
4.0	40.97	985.1	1.0243	8.533	1.0161	19044	14.56	0.984
5.0	51.51	980.4	1.0302	8.581	1.0200	23841	18.39	0.980
6.0	62.16	975.5	1.0359	8.629	1.0261	28890	22.30	0.975
7.0	72.92	970.5	1.0417	8.677	1.0304	33892	26.30	0.971
8.0	83.79	966.3	1.0474	8.725	1.0359	38946	30.38	0.968
9.0	94.78	960.1	1.0531	8.772	1.0416	44063	34.55	0.961
10.0	105.88	954.7	1.0588	8.820	1.0476	49214	38.82	0.956
11.0	117.11	949.2	1.0646	8.868	1.0535	54430	43.18	0.951
12.0	128.45	943.6	1.0704	8.916	1.0597	59700	47.64	0.946
13.0	139.91	938.0	1.0762	8.965	1.0661	65028	52.20	0.940
14.0	151.49	932.3	1.0821	9.014	1.0726	70413	56.87	0.934
15.0	163.21	928.5	1.0881	9.063	1.0793	75858	61.65	0.928
16.0	175.05	920.7	1.0941	9.114	1.0862	81363	66.55	0.922

Potassium Formate Brine Table

HCOOK (Wt%)	HCOOK (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correction Factor	Potassium (mg/L)	lbs HCOOK/ bbl H_2O	Activity
17.0	187.03	918.8	1.1002	9.164	1.0931	86930	71.56	0.915
18.0	199.14	908.9	1.1064	9.216	1.1003	92561	76.68	0.908
19.0	211.40	902.9	1.1126	9.268	1.1076	98257	81.95	0.901
20.0	223.80	896.8	1.1190	9.321	1.1151	104019	87.34	0.894
21.0	236.34	890.7	1.1254	9.375	1.1227	109850	92.87	0.886
22.0	249.04	884.5	1.1320	9.429	1.1305	116750	98.54	0.878
23.0	261.88	878.3	1.1386	9.485	1.1386	121721	104.36	0.870
24.0	274.88	872.0	1.1453	9.541	1.1467	127763	110.33	0.862
25.0	288.04	865.7	1.1522	9.598	1.1552	133880	116.46	0.854
26.0	301.36	859.3	1.1591	9.666	1.1638	140071	122.75	0.845
27.0	314.84	852.8	1.1661	9.714	1.1726	146337	129.22	0.836
28.0	328.49	846.2	1.1732	9.773	1.1817	152680	135.87	0.827
29.0	342.30	839.6	1.1804	9.832	1.1911	159100	142.70	0.818
30.0	356.29	832.8	1.1876	9.883	1.2007	165599	149.73	0.809
31.0	370.44	826.0	1.1950	9.954	1.2106	172176	156.96	0.799
32.0	384.76	819.1	1.2024	10.016	1.2209	178833	164.41	0.789

Potassium Formate Brine Table

HCOOK (Wt%)	HCOOK (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correction Factor	Potassium (mg/L)	lbs HCOOK/ bbl H_2O	Activity
33.0	399.25	812.1	1.2099	10.078	1.2314	185569	172.08	0.780
34.0	413.92	804.9	1.2174	10.141	1.2423	192386	179.98	0.770
35.0	428.76	797.7	1.2250	10.204	1.2536	199283	188.12	0.760
36.0	443.77	790.3	1.2327	10.268	1.2653	206261	196.52	0.750
37.0	458.96	782.9	1.2404	10.333	1.2773	213320	205.19	0.740
38.0	474.32	775.3	1.2482	10.398	1.2899	220459	214.13	0.730
39.0	489.85	767.6	1.2560	10.463	1.3028	227679	223.37	0.719
40.0	505.56	759.7	1.2639	10.528	1.3163	234981	232.91	0.709
41.0	521.44	751.7	1.2718	10.594	1.3303	242363	242.78	0.699
42.0	537.50	743.6	1.2798	10.660	1.3448	249826	252.99	0.689
43.0	553.73	735.3	1.2877	10.727	1.3599	257369	263.56	0.678
44.0	570.13	726.9	1.2958	10.794	1.3756	264993	274.51	0.668
45.0	586.71	718.4	1.3038	10.861	1.3920	272697	285.85	0.658
46.0	603.46	709.7	1.3119	10.928	1.4091	280482	297.61	0.648
47.0	620.38	700.8	1.3200	10.996	1.4269	288348	309.82	0.638
48.0	637.48	691.8	1.3281	11.063	1.4454	296296	322.50	0.627

Potassium Formate Brine Table

HCOOK (Wt%)	HCOOK (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correction Factor	Potassium (mg/L)	lbs HCOOK/ bbl H_2O	Activity
49.0	654.76	682.7	1.3362	11.131	1.4648	304325	335.67	0.617
50.0	672.21	673.5	1.3444	11.199	1.4850	312436	349.37	0.607
51.0	689.84	664.0	1.3526	11.267	1.5081	320630	363.63	0.597
52.0	707.65	654.4	1.3609	11.336	1.5281	328908	378.48	0.587
53.0	725.64	644.7	1.3691	11.405	1.5512	337272	393.97	0.576
54.0	743.82	634.8	1.3774	11.474	1.5754	345722	410.13	0.566
55.0	762.19	624.7	1.3858	11.544	1.6007	354262	427.01	0.556
56.0	780.76	614.6	1.3942	11.614	1.6272	362893	444.65	0.546
57.0	799.54	604.2	1.4027	11.684	1.6550	371618	463.12	0.535
58.0	818.52	593.8	1.4112	11.756	1.6841	380440	482.46	0.526
59.0	837.71	583.2	1.4199	11.827	1.7147	389363	502.75	0.514
60.0	857.14	572.5	1.4286	11.900	1.7469	398391	52706	0.504
61.0	876.80	561.6	1.4374	11.973	1.7807	407529	546.45	0.493
62.0	896.71	550.6	1.4463	12.048	1.8162	416783	570.02	0.482
63.0	916.88	539.5	1.4564	12.123	1.8537	426167	594.87	0.471
64.0	937.32	528.2	1.4646	12.200	1.8932	435661	621.10	0.459

Potassium Formate Brine Table

HCOOK (Wt%)	HCOOK (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correction Factor	Potassium (mg/L)	lbs HCOOK/ bbl H_2O	Activity
65.0	958.06	516.8	1.4739	12.278	1.9349	445300	648.83	0.447
66.0	979.11	505.3	1.4835	12.358	1.9790	455083	678.19	0.436
67.0	1000.49	493.7	1.4933	12.439	2.0267	465020	709.33	0.423
68.0	1022.22	481.9	1.5033	12.522	2.0751	476121	742.41	0.409
69.0	1044.33	470.0	1.5135	12.608	2.1275	486397	777.63	0.396
70.0	1066.84	458.0	1.5241	12.695	2.1832	495861	815.20	0.381
71.0	1089.79	445.9	1.5349	12.788	2.2425	506525	855.35	0.366
72.0	1113.20	433.7	1.5461	12.879	2.3058	517405	898.38	0.350
73.0	1137.10	421.3	1.5677	12.976	2.3734	528517	944.59	0.333
74.0	1181.54	408.8	1.5697	13.075	2.4459	539876	994.36	0.314
75.0	1186.56	398.2	1.5821	13.179	2.5238	551503	1048.11	0.294

Properties of 85% Calcium Nitrate Solutions

Properties of 85% Calcium Nitrate Solutions (at 25°C)

Percent Weight	Specific Gravity (g/cm^3)	Density (lb/gal)	85% $Ca(NO_3)_2$	H_2O Using 85% $Ca(NO_3)_2$ (L/m^3)	$Ca(NO_3)_2$ (mg/L)	Calcium (mg/L)	Volume Increase-Factor 85% $Ca(NO_3)_2$	Aw
1	1.005	8.39	10	997	10089	2080	1.002	0.998
2	1.012	8.45	20	993	20043	4191	1.007	0.995
3	1.019	8.5	30	989	30762	5327	1.011	0.993
4	1.026	8.56	41	985	41349	8490	1.016	0.990
5	1.033	8.62	51	980	52105	10680	1.021	0.988
6	1.040	8.68	62	976	63036	12897	1.025	0.985
7	1.047	8.74	73	972	74143	15142	1.030	0.983
8	1.054	8.80	84	968	85429	17416	1.034	0.980
9	1.061	8.85	95	963	96898	19718	1.039	0.977
10	1.068	8.91	106	959	108552	22050	1.044	0.974
11	1.075	8.97	118	954	120395	24411	1.049	0.972
12	1.082	9.03	129	950	132429	26802	1.054	0.969
13	1.090	9.09	141	945	144657	29224	1.059	0.966
14	1.097	9.15	152	940	157083	31676	1.064	0.963
15	1.104	9.21	164	935	169708	34160	1.069	0.960

Properties of 85% Calcium Nitrate Solutions (at 25°C)

Percent Weight	Specifc Gravity (g/cm^3)	Density (lb/gal)	85% $Ca(NO_3)_2$	H_2O Using 85% $Ca(NO_3)_2$ (L/m^3)	$Ca(NO_3)_2$ (mg/L)	Calcium (mg/L)	Volume Increase-Factor 85% $Ca(NO_3)_2$	Aw
16	1.111	9.27	175	930	182538	36676	1.074	0.956
17	1.119	9.34	189	925	195573	39224	1.080	0.953
18	1.126	9.40	201	920	208818	41805	1.086	0.950
19	1.134	9.46	214	915	222274	44419	1.092	0.948
20	1.141	9.52	226	910	235946	47067	1.098	0.942
21	1.149	9.58	239	905	249836	49748	1.104	0.939
22	1.156	9.65	252	899	263948	52464	1.111	0.935
23	1.164	9.71	265	894	278283	56215	1.117	0.931
24	1.171	9.78	279	888	292846	58001	1.124	0.927
25	1.179	9.84	292	882	307538	60823	1.132	0.922
26	1.187	9.91	306	876	322664	63681	1.139	0.918
27	1.195	9.97	320	871	337925	66576	1.147	0.913
28	1.203	10.04	334	865	353426	69508	1.155	0.909
29	1.211	10.10	348	858	369169	72477	1.163	0.904
30	1.219	10.17	362	852	385156	75484	1.172	0.898

Properties of 85% Calcium Nitrate Solutions (at 25°C)

Percent Weight	Specifc Gravity (g/cm^3)	Density (lb/gal)	85% $Ca(NO_3)_2$	H_2O Using 85% $Ca(NO_3)_2$ (L/m^3)	$Ca(NO_3)_2$ (mg/L)	Calcium (mg/L)	Volume Increase-Factor 85% $Ca(NO_3)_2$	Aw
31	1.227	10.24	377	846	401392	78530	1.181	0.893
32	1.235	10.31	392	839	417878	81614	1.190	0.888
33	1.243	10.38	406	833	434618	84738	1.200	0.882
34	1.252	10.44	421	826	451615	87901	1.210	0.876
35	1.260	10.51	437	820	468872	91105	1.220	0.870
36	1.268	10.59	452	813	486392	94349	1.231	0.864
37	1.277	10.66	468	806	504178	97634	1.242	0.857
38	1.286	10.73	484	799	522232	100961	1.253	0.851
39	1.294	10.80	500	791	540558	104329	1.265	0.844
40	1.303	10.87	516	784	559159	107740	1.278	0.837
41	1.312	10.95	532	776	578038	111193	1.291	0.829
42	1.321	11.02	549	769	597197	114690	1.304	0.821
43	1.33	11.10	566	761	616640	118230	1.318	0.814
44	1.339	11.17	583	753	636370	121815	1.332	0.805
45	1.348	11.25	600	745	656389	125444	1.347	0.797

Properties of 85% Calcium Nitrate Solutions (at 25°C)

Percent Weight	Specifc Gravity (g/cm^3)	Density (lb/gal)	85% $Ca(NO_3)_2$	H_2O Using 85% $Ca(NO_3)_2$ (L/m^3)	$Ca(NO_3)_2$ (mg/L)	Calcium (mg/L)	Volume Increase-Factor 85% $Ca(NO_3)_2$	Aw
46	1.357	11.33	617	737	676701	129117	1.362	0.788
47	1.367	11.41	635	729	697308	132837	1.377	0.779
48	1.376	11.49	653	720	718214	136602	1.394	0.770
49	1.386	11.57	671	712	739421	140413	1.410	0.760
50	1.396	11.65	689	703	760933	144271	1.428	0.751

Chemical Information

This section contains the following information:

- **International Atomic Weights**
- **Chemical Formulas of Common Treating Agents**
- **Moh's Hardness Scale**
- **Specific Gravity & Hardness: Common Oil Field Materials**
- **pH Ranges of Common Indicators**
- **Approximate pH of Acids, Bases, and Oil Field Chemicals**
- **Normality (N) of Solutions**
- **Chemicals Required to Remove Ionic Contaminants**
- **Effect of Salt on Calcium Solubility @ 72°F**
- **Effect of Caustic Soda on Calcium Solubility @ 72°F**

International Atomic Weights

Element	Symbol	Atomic Number	Atomic Weight*
Actinium	Ac	89	227.0278
Aluminum	Al	13	26.9815
Americium	Am	95	(243)
Antimony	Sb	51	121.75
Argon	Ar	18	39.948
Arsenic	As	33	74.9216
Astatine	At	85	(210)
Barium	Ba	56	137.34
Berkelium	Bk	97	(247)
Beryllium	Be	4	9.0122
Bismuth	Bi	83	208.9804
Boron	B	5	10.81
Bromine	Br	35	79.904
Cadmium	Cd	48	112.40
Calcium	Ca	20	40.08
Californium	Cf	98	(251)
Carbon	C	6	12.011
Cerium	Ce	58	140.12
Cesium	Cs	55	132.9054
Chlorine	Cl	17	35.453
Chromium	Cr	24	51.996
Cobalt	Co	27	58.9332
Copper	Cu	29	63.546
Curium	Cm	96	(247)
Dysprosium	Dy	66	162.50
Einsteinium	Es	99	(254)
Erbium	Er	68	167.26
Europium	Eu	63	151.96
Fermium	Fm	100	(257)
Fluorine	F	9	18.9984
Francium	Fr	87	(223)
Gadolinium	Gd	64	157.25
Gallium	Ga	31	69.72
Germanium	Ge	32	72.59
Gold	Au	79	196.9665
Hafnium	Hf	72	178.49

International Atomic Weights (continued)

Element	Symbol	Atomic Number	Atomic Weight*
Hahnium	Ha	105	(262)
Helium	He	2	4.0026
Holmium	Ho	67	164.9304
Hydrogen	H	1	1.0079
Iridium	In	49	114.82
Iodine	I	53	126.9045
Iridium	Ir	77	192.22
Iron	Fe	26	55.847
Krypton	Kr	36	83.80
Lanthanum	La	57	138.9055
Lawerencium	Lr	103	(260)
Lead	Pb	82	207.2
Lithium	Li	3	6.941
Lutetium	Lu	71	174.97
Magnesium	Mg	12	24.305
Manganese	Mn	25	54.9380
Mendelevium	Md	101	(258)
Mercury	Hg	80	200.59
Molybdenum	Mo	42	95.94
Neodymium	Nd	60	144.24
Neon	Ne	10	20.179
Neptunium	Np	93	237.0482
Nickel	Ni	28	58.70
Niobium	Nb	41	92.9064
Nitrogen	N	7	14.0067
Nobelium	No	102	(255)
Osmium	Os	76	190.2
Oxygen	O	8	15.9994
Palladium	Pd	46	106.4
Phosphorus	P	15	30.9738
Platinum	Pt	78	195.09
Plutonium	Pu	94	(244)
Polonium	Po	84	(209)
Potassium	K	19	39.098
Praseodymium	Pr	59	140.9077
Promethium	PM	61	(145)
Protactinium	Pa	91	231.0359

International Atomic Weights (continued)

Element	Symbol	Atomic Number	Atomic Weight*
Radium	Ra	88	226.0254
Radon	Rn	86	(222)
Rhenium	Re	75	186.207
Rhodium	Rh	45	102.9055
Rubidium	Rb	37	85.4678
Rutherfordium	Rf	104	(261)
Ruthenium	Ru	44	101.07
Samarium	Sm	62	150.4
Scandium	SC	21	44.9559
Selenium	Se	34	78.96
Silicon	Si	14	28.086
Silver	Ag	47	107.868
Sodium	Na	11	22.9898
Strontium	Sr	38	87.62
Sulfur	S	16	32.06
Tantalum	Ta	73	180.9479
Technetium (Masurium)	Tc	43	(97)
Tellurium	Te	52	127.60
Terbium	Tb	65	158.9254
Thallium	TI	81	204.37
Thorium	Th	90	232.0381
Thulium	Tm	69	168.9342
Tin	Sn	50	118.69
Titanium	Ti	22	47.90
Tungsten	W	74	183.85
Uranium	U	92	238.029
Vanadium	V	23	50.9414
Xenon	Xe	54	131.30
Ytterbium	Yb	70	173.04
Yttrium	Y	39	88.9059
Zinc	Zn	30	65.38
Zirconium	Zr	40	91.22

* Parentheses ( ) denote most stable or best-known isotope.

Source: *Perry's Chemical Engineers' Handbook, Sixth Edition.*

Chemical Formulas of Common Treating Agents

Common Treating Agent	Chemical Formula
Aluminum stearate	$Al(Cl_8H_{36}O_2)_3$
Ammonium bisulfite	$(NH_4)HSO_3$
Anhydrite	$CaSO_4$
Barite (MIL-BAR®)	$BaSO_4$
Calcium carbonate	$CaCO_3$
Calcium chloride	$CaCl_2$
Caustic soda (Sodium hydroxide)	$NaOH$
Caustic potash (Potassium hydroxide)	KOH
Galena (Lead sulfide)	PbS
Gypsum	$CaSO_4 \bullet 2H_2O$
Lime	$Ca(OH)_2$
Potassium chloride	KCl
Phosphoric acid	H_3PO_4
Quick lime	CaO
Sodium acid pyrophosphate (SAPP)	$Na_2H_2P_2O_7$
Sodium bicarbonate	$NaHCO_3$
Sodium carbonate (Soda ash)	Na_2CO_3
Sodium chloride	$NaCl$
Sodium carboxymethylcellulose	$RCH_2COO^-Na^+$
Sodium sulfite	Na_2SO_3
Sodium thiosulfate	$Na_2S_2O_3$
Zinc carbonate (MIL-GARD®)	$2ZnCO_3 \bullet 3Zn(OH)_2$

Moh's Hardness Scale

Mineral	Scale
Talc	1 (softest)
Gypsum	2
Calcite	3
Flourite	4
Apatite	5
Orthoclase Feldspar	6
Quartz	7
Topaz	8
Corundum	9
Diamond	10

Specific Gravity & Hardness: Common Oil Field Materials

Material	Chemical Formula	Specific Gravity	Moh's Hardness
Anhydrite	$CaSO_4$	2.9	—
Attapulgite (SALTWATER GEL®)	—	2.3 - 2.7	—
Barite (MIL-BAR®)	$BaSO_4$	4.0 - 4.5	3.0 - 3.5
Bentonite (MILGEL®)	—	2.3 - 2.7	1.0 - 2.0
Calcite (Limestone)	$CaCO_3$	2.7 - 2.9	3.0
Calcium chloride	$CaCl_2$	1.95	—
Cement	—	3.1 - 3.2	—
Clay	—	2.5 - 2.7	—
Diesel oil	—	0.85	—
Dolomite	$CaMg(CO_3)_2$	2.86	3.5 - 4.0
Feldspar	—	2.4 - 2.7	—
Galena	PbS	6.95	2.5 - 2.75
Graphite	C	2.09 - 2.23	1.0 - 2.0
Gypsum	$CaSO_4 \bullet 2H_2O$	2.30 - 2.37	2.0
Halite (Salt)	NaCl	2.16 - 2.17	2.5
Hematite (DENSIMIX®)	Fe_2O_3	5.0 - 5.3	5.0 - 6.0
Illite (Clay)	—	2.6 - 2.9	1.0 - 2.0
Ilmenite	$FeTiO_3$	4.68 - 4.76	5.0 - 6.0
Magnesite	$MgCO_3$	2.98 - 3.44	3.5 - 4.5
Montmorillonite (Clay)	—	2.0 - 3.0	1.0 - 2.0
Pyrite	FeS_2	5.02	6.0 - 6.5
Quartz	SiO_2	2.65	7.0
Salt	NaCl	2.2	—
Sand	—	2.1 - 2.7	—
Shale	—	2.2 - 2.9	—
Siderite	$FeCO_3$	3.96	4.0 - 4.5
Slate	—	2.7 - 2.8	—
Smithsonite	$ZnCO_3$	3.8	4.0 - 4.5
Sylvite (Muriate of potash)	KCl	1.99	2.0
Water (Fresh)	H_2O	1.00	—

pH Ranges of Common Indicators

Name	pH Range	Color	→	Change
Cresol red*	0.4 - 1.8	Red	→	Yellow
	7.0 - 8.8	Yellow	→	Red
Thymol blue	1.2 - 2.8	Red	→	Yellow
Metacresol purple*	1.2 - 2.8	Red	→	Yellow
	7.4 - 9.0	Yellow	→	Purple
Bromophenol blue	3.0 - 4.6	Yellow	→	Blue
Congo red	3.0 - 5.0	Blue	→	Red
Methyl orange	3.2 - 4.4	Red	→	Yellow
Bromocresol green	3.8 - 5.4	Yellow	→	Blue
Ethyl red	4.0 - 5.8	Colorless	→	Red
Methyl red	4.8 - 6.0	Red	→	Yellow
Bromocresol purple	5.2 - 6.8	Yellow	→	Purple
Bromothymol blue	6.0 - 7.6	Yellow	→	Blue
Phenol red	6.6 - 8.0	Yellow	→	Red
Neutral red	6.8 - 8.0	Red	→	Amber
* (Cresol red)	7.0 - 8.8	Yellow	→	Red
* (Metacresol purple)	7.4 - 9.0	Yellow	→	Purple
Phenolphthalein	8.2 - 10.0	Colorless	→	Pink
Thymolphthalein	9.4 - 10.6	Colorless	→	Blue
Alizarin yellow R	10.1 - 12.0	Yellow	→	Red
2,4,6 Trinitrotoluene	11.5 - 13.0	Colorless	→	Orange
1,3,5 Trinitrobenzene	12.0 - 14.0	Colorless	→	Orange

Approximate pH of Acids, Bases, and Oil Field Chemicals

Acids	pH
Acetic, N	2.4
Acetic, 0.1N	2.9
Acetic, 0.01N	3.4
Alum, 0.1N	3.2
Boric, 0.1N	5.2
Carbonic (saturated)	3.8
Citric, 0.1N	2.2
Formic, 0.1N	2.3
Hydrochloric, N	0.1
Hydrochloric, 0.1N	1.1
Hydrochloric, 0.01N	2.0
Hydrogen sulfide, 0.1N	4.1
Orthophosphoric, 0.1N	1.5
Oxalic, 0.1N	1.6
Sulfuric, N	0.3
Sulfuric, 0.1N	1.2
Sulfuric, 0.01N	2.1
Sulfurous, 0.1N	1.5

Bases	pH
Ammonia, N	11.6
Ammonia, 0.1N	11.1
Ammonia, 0.01N	10.6
Borax, 0.1N	9.2
Calcium carbonate (saturated)	9.4
Calcium hydroxide (saturated)	12.4
Ferrous hydroxide (saturated)	9.5
Lime (saturated)	12.4
Magnesia (saturated)	10.5
Potassium hydroxide, N	14.0
Potassium hydroxide, 0.1N	13.0
Potassium hydroxide, 0.01N	12.0
Sodium bicarbonate, 0.1N	8.4
Sodium carbonate, 0.1N	11.6
Sodium hydroxide, N	14.0
Sodium hydroxide, 0.1N	13.0
Sodium hydroxide, 0.01N	12.0

Approximate pH of Acids, Bases, and Oil Field Chemicals (continued)

Oil Field Chemicals	pH
CHEMTROL® X	9.0 - 10.0
FILTREX™	10.0
LIGC®	5.0 - 6.0
LIGCON®	9.0 - 10.0
MILSTARCH®	7.0
MIL-TEMP® (ALL-TEMP™)	7.0
NEW-DRILL® HP (2% solution)	10.2
NEW-TROL™	9.0 - 10.0
OILFOS®	7.0
PERMA-LOSE™ HT	7.0
PROTECTOMAG® M	7.0
SAPP	4.2
SHALE-TROL®	2.0 - 3.0
*SOLTEX™	8.2
UNI-CAL® (3% solution)	≈ 3.0

** SOLTEX is a registered trademark of Drilling Specialities Company.*

Normality (N) of Solutions

The normality (N) of a solution is the number of equivalent weights of a chemical (solute) per liter of solution. The equivalent weight of an acid or base depends upon the reaction it undergoes. In most reactions in fluid systems, an equivalent weight (1) is the molecular weight of the chemical divided by the charges (+ or –) supplied to the reaction. For example, what is the equivalent weight of H_2SO_4 (sulfuric acid)?

$$H_2SO_4 = (2 - \text{Hydrogen}) + (1 - \text{Sulfur}) + (4 - \text{Oxygen})$$

$$\text{Molecular weight} = (2 \times 1) + (1 \times 32) + (4 \times 16) = 98$$

As an acid, H_2SO_4 supplies 2 H^+ ions or a total of 2(+). Therefore, one equivalent weight of H_2SO_4 is equal to:

$$\frac{98}{2} = 49 \text{ g of } H_2SO_4$$

A 1.0N solution of H_2SO_4 would have 49 g of acid and enough water to bring the total volume of solution of one liter (1000 mL). A 0.1N solution of H_2SO_4 would have 4.9 g of acid and enough water to bring the total volume of solution of one liter (1000 mL).

Chemicals Required to Remove Ionic Contaminants

Contaminant (mg/L)	×	Factor	=	Treating Chemical (lb_m/bbl)
Ca^{++}	×	0.00093	=	Na_2CO_3 (Soda ash)
Ca^{++}	×	0.00074	=	$NaHCO_3$ (Bicarb.of soda)*
Ca^{++}	×	0.00097	=	$Na_2H_2P_2O_7$ (SAPP)
Ca^{++}	×	0.00173	=	$BaCO_3$ (Barium carbonate)
Mg^{++}	×	0.00093	=	Na_2CO_3
Mg^{++}	×	0.00116	=	NaOH (Caustic soda)*
$SO_4^{=}$	×	0.00073	=	$BaCO_3$
$CO_3^{=}$	×	0.00043	=	$Ca(OH)_2$ (Lime)**
$CO_3^{=}$	×	0.00100	=	$CaSO_4 \bullet 2H_2O$ (Gypsum)
HCO_3^{-}	×	0.00021	=	$Ca(OH)_2$**
HCO_3^{-}	×	0.00200	=	NaOH (Caustic soda)
$PO_4^{\equiv}$	×	0.00041		$Ca(OH)_2$**

* Best to use where pH and calcium are high.
** Use with caution; may cause high pH.

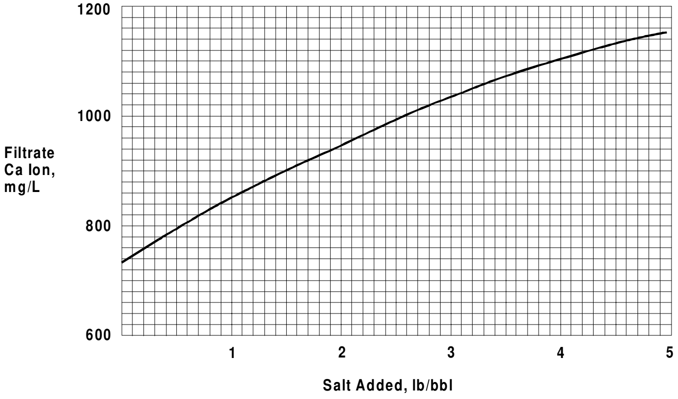
Example:

Titration of the filtrate shows a calcium level of 650 mg/L. To remove all but approximately 100 mg/L, treat 550 mg/L (650 – 100 = 550) of calcium with soda ash.

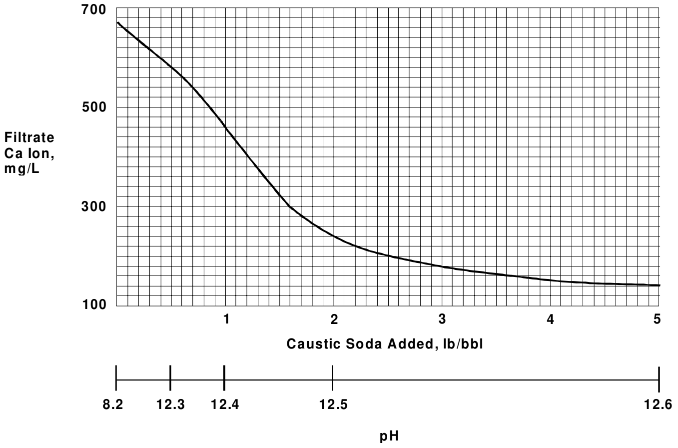
Therefore, soda ash required is approximately

$$550 \times 0.00093 = 0.51\ lb_m/bbl.$$

Effect of Salt on Calcium Solubility @ 72°F



Effect of Caustic Soda on Calcium Solubility @ 72°F



Conversion Factors

To Convert	Multiply By	To Obtain
A		
acres	1.60 × 10^{2}	rods
acres	4.047 × 10^{-1}	hectares
acres	4.35 × 10^{4}	sq feet
acres	4.047 × 10^{3}	sq meters
acres	1.562 × 10^{-3}	sq miles
acres	4.840 × 10^{3}	sq yards
acre-feet	4.356 × 10^{4}	cu feet
acre-feet	3.259 × 10^{5}	gal
amperes/sq cm	6.452	amps/sq in.
amperes/sq meter	6.452 × 10^{-4}	amps/sq in.
ampere-hr	3.600 × 10^{3}	coulombs
angstrom unit	3.937 × 10^{-9}	in.
angstrom unit	1.0 × 10^{-4}	microns or p
ares	2.471 × 10^{-2}	acres (U.S.)
ares	1.196 × 10^{2}	sq yards
ares	1.0 × 10^{2}	sq meters
astronomical unit	1.495 × 10^{3}	km
atmospheres	7.6 × 10^{1}	cm of mercury (at 0°C)
atmospheres	3.39 × 10^{1}	ft water (at 4°C)
atmospheres	2.992 × 10^{1}	in. of mercury (at 0°C)
atmospheres	7.6 × 10^{-1}	meters of mercury (at 0°C)
atmospheres	7.6 × 10^{2}	mm of mercury (at 0°C)
atmospheres	1.0333	kg/sq cm
atmospheres	1.0333 × 10^{4}	kg/sq meter
B		
barrels (U.S., dry)	3.281	bushels
barrels (U.S., dry)	7.056 × 10^{3}	cu in.
barrels (U.S., dry)	1.05 × 10^{2}	quarts (dry)

barrels (U.S., liquid)	3.15 × 10^{1}	gal
barrels (oil)	4.2 × 10^{1}	gal (oil)
bars	9.869 × 10^{-1}	atmospheres
bars	1.0 x 10^{6}	dynes/sq cm
bars	1.020 × 10^{1}	kg/sq meter
bars	2.089 × 10^{3}	lb/sq foot
bars	1.45 × 10^{1}	lb/sq in.
barye	1.00	dynes/sq cm
Btu	1.0409 × 10^{1}	liter-atmospheres
Btu	1.0550 × 10^{10}	ergs
Btu	7.7816 × 10^{2}	foot-lb
Btu	2.52 × 10^{2}	gram-calories
Btu	3.927 × 10^{-4}	horsepower-hr
Btu	1.005 × 10^{3}	joules
Btu	2.52 ×10^{-1}	kg-calories
Btu	1.0758 ×10^{2}	kg-meters
Btu	2.928 ×10^{-4}	kilowatt-hr
Btu/hr	2.162 ×10^{-1}	foot-lb/sec
Btu/hr	7.0 × 10^{-2}	gram-calories/sec
Btu/hr	3.929 × 10^{-4}	horsepower
Btu/hr	2.931 × 10^{-1}	watts
Btu/min	1.296 × 10^{1}	foot-lb/sec
Btu/min	2.356 × 10^{-2}	horsepower
Btu/min	1.757 × 10^{-2}	kilowatts
Btu/min	1.757 × 10^{1}	watts
Btu/sq feet/min	1.22 × 10^{-1}	watts/sq in.
bucket (British, dry)	1.8184 × 10^{4}	cu cm
bushels	1.2445	cu feet
bushels	2.1504 × 10^{3}	cu in.
bushels	3.524 × 10^{-2}	cu meters
bushels	3.524 × 10^{1}	liters
bushels	4.0	pecks

bushels	6.4×10^{1}	pints (dry)
bushels	3.2×10^{1}	quarts (dry)
C		
calories, gram (mean)	3.9685×10^{-3}	Btu (mean)
centares	1.0	sq meters
centigrade (degrees)	(°C × 9/5) + 32	fahrenheit (degrees)
centigrade (degrees)	°C + 273.18	kelvin (degrees)
centigrams	1.0×10^{-2}	grams
centiliters	3.382×10^{-1}	ounce (fluid) U.S.
centiliters	6.103×10^{-1}	cu in.
centiliters	2.705	drams
centiliters	1.0×10^{-2}	liters
centimeters	3.281×10^{-2}	feet
centimeters	3.937×10^{-1}	in.
centimeters	1.0×10^{-5}	km
centimeters	1.0×10^{-2}	meters
centimeters	6.214×10^{-6}	miles
centimeters	1.0×10^{1}	mm
centimeters	3.937×10^{2}	mils
centimeters	1.094×10^{-2}	yards
centimeters	1.0×10^{4}	microns
centimeters	1.0×10^{8}	angstrom units
centimeter-dynes	1.020×10^{-3}	cm-grams
centimeter-dynes	1.020×10^{-8}	meter-kg
centimeter-dynes	$7.376 \times 1\ 0^{-8}$	lb-foot
centimeter-grams	9.807×10^{2}	cm-dynes
centimeter-grams	1.0×10^{-5}	meter-kg
centimeter-grams	7.233×10^{-5}	lb-foot
centimeters of mercury	1.316×10^{-2}	atmospheres
centimeters of mercury	4.461×10^{-1}	feet of water
centimeters of mercury	1.36×10^{2}	kg/sq meter
centimeters of mercury	2.785×10^{1}	lb/sq foot

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centimeters of mercury	1.934×10^{-1}	lb/sq in.
centimeters/sec	1.969	feet/min
centimeters/sec	3.281×10^{-2}	feet/sec
centimeters/sec	3.6×10^{-2}	km/hr
centimeters/sec	1.943×10^{-2}	knots
centimeters/sec	6.0×10^{-1}	meters/min
centimeters/sec	2.237×10^{-2}	miles/hr
centimeters/sec	3.728×10^{-1}	miles/min
centimeters/sec/sec	3.281×10^{-2}	feet/sec/sec
centimeters/sec/sec	3.6×10^{-2}	km/hr/sec
centimeters/sec/sec	1.0×10^{-2}	meters/sec/sec
centimeters/sec/sec	2.237×10^{-2}	miles/hr/sec
centipoise	1.0×10^{-2}	grams/cm-sec
centipoise	6.72×10^{-4}	lb/foot-sec
centipoise	2.4	lb/foot-hr
cords	8.0	cord feet
cord feet	1.6×10^{1}	cu feet
coulombs	2.998×10^{9}	statcoulombs
coulombs	1.036×10^{-5}	faradays
coulombs/sq cm	6.452	coulombs/sq in.
coulombs/sq cm	1.0×10^{4}	coulombs/sq meter
coulombs/sq in.	1.550×10^{-1}	coulombs/sq cm
coulombs/sq in.	1.550×10^{3}	coulombs/sq meter
coulombs/sq meter	1.0×10^{-4}	coulombs/sq cm
coulombs/sq meter	6.452×10^{-4}	coulombs/sq in.
cubic centimeters	3.531×10^{-5}	cu feet
cubic centimeters	6.102×10^{-2}	cu in.
cubic centimeters	1.0×10^{-6}	cu meters
cubic centimeters	1.308×10^{-6}	cu yards
cubic centimeters	2.642×10^{-4}	gal (U.S., liquid)
cubic centimeters	1.0×10^{-3}	liters
cubic centimeters	2.113×10^{-3}	pints (U.S., liquid)

cubic centimeters	1.057×10^{-3}	quarts (U.S., liquid)
cubic feet	8.036×10^{-1}	bushels (dry)
cubic feet	2.8320×10^{4}	cu cm
cubic feet	1.728×10^{3}	cu in.
cubic feet	2.832×10^{-2}	cu meters
cubic feet	3.704×10^{-2}	cu yards
cubic feet	7.48052	gal (U.S., liquid)
cubic feet	2.832×10^{1}	liters
cubic feet	5.984×10^{1}	pints (U.S., liquid)
cubic feet	2.992×10^{1}	quarts (U.S., liquid)
cubic feet/min	4.72×10^{2}	cu cm/sec
cubic feet/min	1.247×10^{-1}	gal/sec
cubic feet/min	4.720×10^{-1}	liters/sec
cubic feet/min	6.243×10^{1}	lb water/min
cubic feet/sec	6.46317×10^{-1}	million gal/day
cubic feet/sec	4.48831×10^{2}	gal/min
cubic in.	1.639×10^{1}	cu cm
cubic in.	5.787×10^{-4}	cu feet
cubic in.	1.639×10^{-5}	cu meters
cubic in.	2.143×10^{-5}	cu yards
cubic in.	4.329×10^{-3}	gal
cubic in.	1.639×10^{-2}	liters
cubic in.	3.463×10^{-2}	pints (U.S., liquid)
cubic in.	1.732×10^{-2}	quarts (U.S., liquid)
cubic meters	2.838×10^{1}	bushels (dry)
cubic meters	1.0×10^{6}	cu cm
cubic meters	3.531×10^{1}	cu feet
cubic meters	6.1023×10^{1}	cu in.
cubic meters	1.308	cu yards
cubic meters	2.642×10^{2}	gal (U.S., liquid)
cubic meters	1.0×10^{3}	liters
cubic meters	$2.11\ 3 \times 10^{3}$	pints (U.S., liquid)

cubic meters	1.057×10^{3}	quarts (U.S., liquid)
cubic yards	7.646×10^{5}	cu cm
cubic yards	2.7×10^{1}	cu feet
cubic yards	4.6656×10^{4}	cu in.
cubic yards	7.646×10^{-1}	cu meters
cubic yards	2.02×10^{2}	gal (U.S., liquid)
cubic yards	7.646×10^{2}	liters
cubic yards	1.6159×10^{3}	pints (U.S., liquid)
cubic yards	8.079×10^{2}	quarts (U.S., liquid)
cubic yards/min	4.5×10^{-1}	cu feet/sec
cubic yards/min	3.367	gal/sec
cubic yards/min	1.274×10^{1}	liters/sec
D		
daltons	1.650×10^{-24}	grams
days	8.64×10^{4}	sec
days	1.44×10^{3}	min
days	2.4×10^{1}	hr
decigrams	1.0×10^{-1}	grams
deciliters	1.0×10^{-1}	liters
decimeters	1.0×10^{-1}	meters
degrees (angle)	1.111×10^{-2}	quadrants
degrees (angle)	1.745×10^{-2}	radians
degrees (angle)	3.6×10^{3}	seconds
degrees/sec	1.745×10^{-2}	radians/sec
degrees/sec	1.667×10^{-1}	rev/min
degrees/sec	2.778×10^{-3}	rev/sec
dekagrams	1.0×10^{1}	grams
dekaliters	1.0×10^{1}	liters
dekameters	1.0×10^{1}	meters
drams (apoth. or troy)	1.3714×10^{-1}	ounces (avdp.)
drams (apoth. or troy)	1.25×10^{-1}	ounces (troy)

drams (U.S., fluid or apoth.)	3.6967	cu cm
drams	1.7718	grams
drams	2.7344×10^{1}	grains
drams	6.25×10^{-2}	ounces
dynes/sq cm	1.0×10^{-2}	ergs/sq mm
dynes/sq cm	9.869×10^{-7}	atmospheres
dynes/sq cm	2.953×10^{-5}	in. of mercury (at 0°C)
dynes/sq cm	4.015×10^{-4}	in. of water (at 4°C)
dynes	1.020×10^{-3}	grams
dynes	1.0×10^{-7}	joules/cm
dynes	1.0×10^{-5}	joules/meter (newton)
dynes	1.020×10^{-6}	km
dynes	7.233×10^{-5}	poundals
dynes	2.248×10^{-6}	lb
dynes/sq cm	1.0×10^{-6}	bars
E		
erg/sec	1.0	dyne-cm/sec
ergs	9.486×10^{-11}	Btu
ergs	1.0	dyne-cm
ergs	7.376×10^{-8}	foot-lb
ergs	2.389×10^{-8}	gram-calories
ergs	1.020×10^{-3}	gram-cm
ergs	3.7250×10^{-14}	horsepower-hr
ergs	1.0×10^{-7}	joules
ergs	2.389×10^{-11}	kg-calories
ergs	1.020×10^{-8}	kg-meters
ergs	2.773×10^{-14}	kilowatt-hr
ergs	2.773×10^{-11}	watt-hr
ergs/sec	5.668×10^{-9}	Btu/min
ergs/sec	4.426×10^{-6}	foot-lb/min
ergs/sec	7.3756×10^{-8}	foot-lb/sec

ergs/sec	1.341×10^{-10}	horsepower
ergs/sec	1.433×10^{-9}	kg-calories/min
ergs/sec	1.0×10^{-10}	kilowatts
F		
fahrenheit (degrees)	(°F – 32) × 5/9	centigrade (degrees)
fathoms	1.8288	meters
fathoms	6.0	feet
feet	3.048×10^{1}	cm
feet	3.048×10^{-4}	km
feet	3.048×10^{-1}	meters
feet	1.645×10^{-4}	miles (naut.)
feet	1.894×10^{-4}	miles (stat.)
feet	3.048×10^{2}	mm
feet	1.2×10^{4}	mils
feet of water	2.95×10^{-2}	atmospheres
feet of water	8.826×10^{-1}	in. of mercury
feet of water	3.048×10^{-2}	kg/sq cm
feet of water	3.048×10^{2}	kg/sq meter
feet of water	6.243×10^{1}	lb/sq foot
feet of water	4.335×10^{-1}	lb/sq in.
feet/min	5.080×10^{-1}	cm/sec
feet/min	1.667×10^{-2}	feet/sec
feet/min	1.829×10^{-2}	km/hr
feet/min	3.048×10^{-1}	meters/min
feet/min	1.136×10^{-2}	miles/hr
feet/sec	3.048×10^{1}	cm/sec
feet/sec	1.097	km/hr
feet/sec	5.921×10^{-1}	knots
feet/sec	1.829×10^{1}	meters min
feet/sec	6.818×10^{-1}	miles/hr
feet/sec	1.136×10^{-2}	miles/min
feet/sec/sec	3.048×10^{1}	cm/sec/sec

feet/sec/sec	1.097	km/hr/sec
feet/sec/sec	3.048×10^{-1}	meters/sec/sec
feet/sec/sec	6.818×10^{-1}	miles/hr/sec
feet/100 ft	1.0	percent grade
foot-lb	1.286×10^{-3}	Btu
foot-lb	1.356×10^{7}	ergs
foot-lb	3.241×10^{-1}	gram-calories
foot-lb	5.050×10^{-7}	horsepower/hr
foot-lb	1.356	joules
foot-lb	3.241×10^{-4}	kg-calories
foot-lb	1.383×10^{-1}	kg-meters
foot-lb	3.766×10^{-7}	kilowatt-hr
foot-lb/min	1.286×10^{-3}	Btu/min
foot-lb/min	1.667×10^{-2}	foot-lb/sec
foot-lb/min	3.030×10^{-5}	horsepower
foot-lb/min	3.241×10^{-4}	kg-calories/min
foot-lb/min	2.260×10^{-5}	kilowatts
foot-lb/sec	4.6263	Btu/hr
foot-lb/sec	7.717×10^{-2}	Btu/min
foot-lb/sec	1.818×10^{-3}	horsepower
foot-lb/sec	1.945×10^{-2}	kg-calories/min
foot lb/sec	1.356×10^{-3}	kilowatts
furlongs	1.25×10^{-1}	miles (U.S.)
furlongs	4.0×10^{1}	rods
furlongs	6.6×10^{2}	feet
furlongs	2.0117×10^{2}	meters
G		
gal	3.785×10^{3}	cu cm
gal	1.337×10^{-1}	cu feet
gal	2.31×10^{2}	cu in.
gal	3.785×10^{-3}	cu meters
gal	4.951×10^{-3}	cu yards

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gal	3.785	liters
gal (liquid, British Imperial)	1.20095	gal (U.S., liquid)
gal (U.S.)	8.3267×10^{-1}	gal (Imp.)
gal of water	8.337	lb of water
gal/min	2.228×10^{-3}	cu feet/sec
gal/min	6.308×10^{-2}	liters/sec
gal/min	8.0208	cu feet/hr
gills (British)	1.4207×10^{2}	cu cm
gills (U.S.)	1.18295×10^{2}	cu cm
gills (U.S.)	1.183×10^{-1}	liters
gills (U.S,)	2.5×10^{-1}	pints (liquid)
grains	3.657×10^{-2}	drams (avdp.)
grains (troy)	1.0	grains (avdp.)
grains (troy)	6.48×10^{-2}	grams
grains (troy)	2.0833×10^{-3}	ounces (avdp.)
grains (troy)	4.167×10^{-2}	pennyweight (troy)
grains/U.S. gal	1.7118×10^{1}	parts/million
grains/U.S. gal	1.4286×10^{2}	lb/million gal
grains/Imp. gal	1.4286×10^{1}	parts/million
grams	9.807×10^{2}	dynes
grams	1.543×10^{1}	grains (troy)
grams	9.807×10^{-5}	joules/cm
grams	9.807×10^{-3}	joules/meter (newtons)
grams	1.0×10^{-3}	kg
grams	1.0×10^{3}	mg
grams	3.527×10^{-2}	ounces (avdp.)
grams	3.215×10^{-2}	ounces (troy)
grams	7.093×10^{-2}	poundals
grams	2.205×10^{-3}	lb
grams/cm	5.6×10^{-3}	lb/in.
grams/cu cm	6.243×10^{1}	lb/cu feet

grams/cu cm	3.613×10^{-2}	lb/cu in.
grams/cu cm	3.405×10^{-7}	lb/mil-foot
grams/liter	5.8417×10^{1}	grains/gal
grams/liter	8.345	lb/1000 gal
grams/liter	6.2427×10^{-2}	lb/cu feet
grams/sq cm	2.0481	lb/sq feet
gram-calories	3.9683×10^{-3}	Btu
gram-calories	4.184×10^{7}	ergs
gram-calories	3.085	foot-lb
gram-calories	1.5596×10^{-6}	horsepower-hr
gram-calories	1.162×10^{-6}	kilowatt-hr
gram-calories	1.162×10^{-3}	watt-hr
gram-calories/sec	1.4286×10^{1}	Btu/hr
gram-centimeters	9.297×10^{-8}	Btu
gram-centimeters	9.807×10^{2}	ergs
gram-centimeters	9.807×10^{-5}	joules
gram-centimeters	2.343×10^{-8}	kg-calories
gram-centimeters	1.0×10^{-5}	kg-meters
H		
hand	1.016×10^{1}	cm
hectares	2.471	acres
hectares	1.076×10^{5}	sq feet
hectograms	1.0×10^{2}	grams
hectoliters	1.0×10^{2}	liters
hectometers	1.0×10^{2}	meters
hectowatts	1.0×10^{2}	watts
horsepower	4.244×10^{1}	Btu/min
horsepower	3.3×10^{4}	foot-lb/min
horsepower	5.50×10^{2}	foot-lb/sec
horsepower (metric)	9.863×10^{-1}	horsepower
horsepower	1.014	horsepower (metric)
horsepower	1.068×10^{1}	kg-calories/min

horsepower	7.457×10^{-1}	kilowatts
horsepower	7.457×10^{2}	watts
horsepower (boiler)	3.352×10^{4}	Btu/hr
horsepower (boiler)	9.803	kilowatts
horsepower-hr	2.547×10^{3}	Btu
horsepower-hr	2.6845×10^{13}	ergs
horsepower-hr	1.98×10^{6}	foot-lb
horsepower hr	6.4119×10^{5}	gram-calories
horsepower-hr	2.684×10^{5}	joules
horsepower-hr	6.417×10^{2}	kg-calories
horsepower-hr	2.737×10^{5}	kg-meters
horsepower-hr	7.457×10^{-1}	kilowatt-hrs
hours	4.167×10^{-2}	days
hours	5.952×10^{-3}	weeks
hours	3.6×10^{3}	seconds
hundredwgts (long)	1.12×10^{2}	lb
hundredwgts (long)	5.0×10^{-2}	tons (long)
hundredwgts (long)	5.08023×10^{1}	kg
hundredwgts (short)	4.53592×10^{-2}	tons (metric)
hundredwgts (short)	4.46429×10^{-2}	tons (long)
hundredwgts (short)	4.53592×10^{1}	kg
I		
inches	2.540	cm
inches	2.540×10^{-2}	meters
inches	1.578×10^{-5}	miles
inches	2.54×10^{1}	mm
inches	1.0×10^{3}	mils
inches	2.778×10^{-2}	yards
inches	2.54×10^{8}	angstrom units
inches	5.0505×10^{-3}	rods
inches of mercury	3.342×10^{-2}	atmospheres
inches of mercury	1.133	feet of water

inches of mercury	3.453×10^{-2}	kg/sq cm
inches of mercury	3.453×10^{2}	kg/sq meter
inches of mercury	7.073×10^{1}	lb/sq feet
inches of mercury	4.912×10^{-1}	lb/sq in.
inches of water (at 4°C)	2.458×10^{-3}	atmospheres
inches of water (at 4°C)	7.355×10^{-2}	in. of mercury
inches of water (at 4°C)	2.54×10^{-3}	kg/sq cm
inches of water (at 4°C)	5.781×10^{-1}	ounces/sq in.
inches of water (at 4°C)	5.204	lb/sq feet
inches of water (at 4°C)	3.613×10^{-2}	lb/sq in.
international ampere	9.998×10^{-1}	absolute ampere (U.S.)
international volt	1.00033	absolute volt (U.S.)
international coulomb	9.99335×10^{-1}	absolute coulomb
J		
joules	9.486×10^{-4}	Btu
joules	1.0×10^{7}	ergs
joules	7.736×10^{-1}	foot-lb
joules	2.389×10^{-4}	kg-calories
joules	1.020×10^{-1}	kg-meters
joules	2.778×10^{-4}	watt-hr
joules/cm	1.020×10^{4}	grams
joules/cm	1.0×10^{7}	dynes
joules/cm	1.0×10^{2}	joules/meter (newtons)
joules/cm	7.233×10^{2}	poundals
joules/cm	2.248×10^{1}	lb
K		
kilograms	9.80665×10^{5}	dynes

kilograms	1.0×10^{3}	grams
kilograms	9.807×10^{-2}	joules/cm
kilograms	9.807	joules/meter (newtons)
kilograms	7.093×10^{1}	poundals
kilograms	2.2046	lb
kilograms	9.842×10^{-4}	tons (long)
kilograms	1.102×10^{-3}	tons (short)
kilograms	3.5274×10^{1}	ounces (avdp.)
kilograms/cu meter	1.0×10^{-3}	grams/cu cm
kiloqrams/cu meter	6.243×10^{-2}	lb/cu foot
kilograms/cu meter	3.613×10^{-5}	lb/cu in.
kilograms/cu meter	3.405×10^{-10}	lb/mil-foot
kilograms/meter	6.72×10^{-1}	lb/foot
kilograms/sq cm	9.80665×10^{5}	dynes/sq cm
kilograms/sq cm	9.678×10^{-1}	atmospheres
kilograms/sq cm	3.281×10^{1}	feet of water
kilograms/sq cm	2.896×10^{1}	in. of mercury
kilograms/sq cm	2.048×10^{3}	lb/sq foot
kilograms/sq cm	1.422×10^{1}	lb/sq in.
kilograms/sq meter	9.678×10^{-5}	atmospheres
kilograms/sq meter	9.807×10^{-5}	bars
kilograms/sq meter	3.281×10^{-3}	feet of water
kilograms/sq meter	2.896×10^{-3}	in. of mercury
kilograms/sq meter	2.048×10^{-1}	lb/sq foot
kilograms/sq meter	1.422×10^{-3}	lb/sq in.
kilograms/sq meter	9.80665×10^{1}	dynes/sq cm
kilograms/sq mm	1.0×10^{6}	kg/sq meter
kilogram-calories	3.968	Btu
kilogram-calories	3.086×10^{3}	foot-lb
kilogram-calories	1.558×10^{-3}	horsepower-hr
kilogram-calories	4.183×10^{3}	joules
kilogram-calories	4.269×10^{2}	kg-meters

kilogram-calories	4.186	kilojoules
kilogram-calories	1.163×10^{-3}	kilowatt-hr
kilogram-calories/min	5.143×10^{1}	foot-lb/sec
kilogram-calories/min	9.351×10^{-2}	horsepower
kilogram-calories/min	6.972×10^{-2}	kilowatts
kilogram-meters	9.296×10^{-3}	Btu
kilogram-meters	9.807×10^{7}	ergs
kilogram-meters	7.233	foot-lb
kilogram-meters	9.807	joules
kilogram-meters	2.342×10^{-3}	kg-calories
kilogram-meters	2.723×10^{-6}	kilowatt-hr
kiloliters	1.0×10^{3}	liters
kiloliters	1.308	cu yards
kiloliters	3.5316×10^{1}	cu feet
kiloliters	2.6418×10^{2}	gal (U.S., liquid)
kilometers	1.0×10^{5}	cm
kilometers	3.281×10^{3}	feet
kilometers	3.937×10^{4}	in.
kilometers	1.0×10^{3}	meters
kilometers	6.214×10^{-1}	miles (statute)
kilometers	5.396×10^{-1}	miles (nautical)
kilometers	1.0×10^{6}	mm
kilometers	1.0936×10^{3}	yards
kilometers/hr	2.778×10^{1}	cm/sec
kilometers/hr	5.468×10^{1}	feet/min
kilometers/hr	9.113×10^{-1}	feet/sec
kilometers/hr	5.396×10^{-1}	knots
kilometers/hr	1.667×10^{1}	meters/min
kilometers/hr	6.214×10^{-1}	miles/hr
kilometers/hr/sec	2.778×10^{1}	cm/sec/sec
kilometers/hr/sec	9.113×10^{-1}	feet/sec/sec
kilometers/hr/sec	2.778×10^{-1}	meters/sec/sec

kilometers/hr/sec	6.214×10^{-1}	miles/hr/sec
kilowatts	5.692×10^{1}	Btu/min
kilowatts	4.426×10^{4}	foot-lb/min
kilowatts	7.376×10^{2}	foot-lb/sec
kilowatts	1.341	horsepower
kilowatts	1.434×10^{1}	kg-calories/min
kilowatts	1.0×10^{3}	watts
kilowatt-hr	3.413×10^{3}	Btu
kilowatt-hr	3.6×10^{13}	ergs
kilowatt-hr	2.655×10^{6}	foot-lb
kilowatt-hr	8.5985×10^{3}	gram-calories
kilowatt-hr	1.341	horsepower-hr
kilowatt-hr	3.6×10^{6}	joules
kilowatt-hr	8.605×10^{2}	kg-calories
kilowatt-hr	3.671×10^{5}	kg-meters
kilowatt-hr	3.53	lb of water evaporated from and at 212°F
kilowatt-hr	2.275×10^{1}	lb of water raised from 62°F to 212°F
knots	6.080×10^{3}	feet/hr
knots	1.8532	km/hr
knots	1.0	nautical miles/hr
knots	1.151	statute miles/hr
knots	2.027×10^{3}	yards/hr
knots	1.689	feet/sec
knots	5.148×10^{1}	cm/sec
L		
league	3.0	miles (approx.)
light year	5.9×10^{12}	miles
light year	9.46091×10^{12}	km
liters	2.838×10^{-2}	bushels (U.S., dry)
liters	1.0×10^{3}	GU cm

liters	3.531×10^{-2}	cu feet
liters	6.102×10^{1}	cu in.
liters	1.0×10^{-3}	cu meters
liters	1.308 × 10-3	cu yard
liters	2.642×10^{-1}	gal (U.S., liquid)
liters	2.113	pint (U.S., liquid)
liters	1.057	quarts (U.S., liquid)
liters/min	5.886×10^{-4}	cu feet/sec
liters/min	4.403×10^{-3}	gal/sec
$\log_{10}$ n	2.303	ln n
ln n	4.343×10^{-1}	$\log_{10}$ n
lumen	7.958×10^{-2}	spherical candlepower
lumen/sq feet	1.0	foot-candles
lumen/sq feet	1.076×10^{1}	lumen/sq meter
lux	9.29×10^{-2}	foot-candles
M		
megohms	1.0×10^{12}	microhms
megohms	1.0×10^{6}	ohms
megmhos/cu cm	1.0×10^{-3}	abmhos/cu cm
megmhos/cu cm	2.54	megmhos/cu in.
megmhos/cu cm	1.662×10^{-1}	mhos/mil feet
megmhos/cu in.	3.937×10^{-1}	megmhos/cu cm
meters	1.0×10^{10}	angstrom units
meters	1.0×10^{2}	cm
meters	5.4681×10^{-1}	fathoms
meters	3.281	feet
meters	3.937×10^{1}	in.
meters	1.0×10^{-3}	km
meters	5.396×10^{-4}	miles (nautical)
meters	6.214×10^{-4}	miles (statute)
meters	1.0×10^{3}	mm
meters	1.094	yards

meters/min	1.667	cm/sec
meters/min	3.281	feet/min
meters/min	5.468×10^{-2}	feet/sec
meters/min	6.0×10^{-2}	km/hr
meters/min	3.238×10^{-2}	knots
meters/min	3.728×10^{-2}	miles/hr
meters/sec	1.968×10^{2}	feet/min
meters/sec	3.281	feet/sec
meters/sec	3.6	km/hr
meters/sec	6.0×10^{-2}	km/min
meters/sec	2.237	miles/hr
meters/sec	3.728×10^{-2}	miles/min
meters/sec/sec	1.0×10^{2}	cm/sec/sec
meters/sec/sec	3.281	feet/sec/sec
meters/sec/sec	3.6	km/hr/sec
meters/sec/sec	2.237	miles/hr/sec
meter-kilograms	9.807×10^{7}	cm-dynes
meter-kilograms	1.0×10^{5}	cm-grams
meter-kilograms	7.233	lb-feet
micrograms	1.0×10^{-6}	grams
microhms	1.0×10^{-12}	megohms
microhms	1.0×10^{-6}	ohms
microliters	1.0×10^{-6}	liters
micromicrons	1.0×10^{-12}	meters
microns	1.0×10^{-6}	meters
miles (nautical)	6.076×10^{3}	feet
miles (nautical)	1.853	km
miles (nautical)	1.853×10^{3}	meters
miles (nautical)	1.1516	miles (statute)
miles (nautical)	2.0254	yards
miles (statute)	1.609×10^{3}	cm
miles (statute)	5.280	feet

miles (statute)	6.336×10^{4}	in,
miles (statute)	1.609	km
miles (statute)	1.609×10^{3}	meters
miles (statute)	8.684×10^{-1}	miles (nautical)
miles (statute)	1.760×10^{3}	yards
miles (statute)	1.69×10^{-13}	light years
miles/hr	4.470×10^{1}	cm/sec
miles/hr	8.8×10^{1}	feet/min
miles/hr	1.467	feet/sec
miles/hr	1.6093	km/hr
miles/hr	2.682×10^{-2}	km/min
miles/hr	8.684×10^{-1}	knots
miles/hr	2.682×10^{1}	meters/min
miles/hr	1.667×10^{-2}	miles/min
miles/hr/sec	4.47×10^{1}	cm/sec/sec
miles/hr/sec	1.467	feet/sec/sec
miles/hr/sec	1.6093	km/hr/sec
miles/hr/sec	4.47×10^{-1}	meters/sec/sec
miles/min	2.682×10^{3}	cm/sec
miles/min	8.8×10^{1}	feet/sec
miles/min	1.6093	km/min
miles/min	8.684×10^{-1}	knots/min
miles/min	6.0×10^{1}	miles/hr
milliers	1.0×10^{3}	kg
millimicrons	1.0×10^{-9}	meters
milligrams	1.5432×10^{-2}	grains
milligrams	1.0×10^{-3}	grams
milligrams/liter	1.0	parts/million
millihenries	1.0×10^{-3}	henries
milliliters	1.0×10^{-3}	liters
millimeters	1.0×10^{-1}	cm
millimeters	3.281×10^{-3}	feet

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millimeters	3.937×10^{-2}	in.
millimeters	1.0×10^{-6}	km
millimeters	1.0×10^{-3}	meters
millimeters	6.214×10^{-7}	miles
millimeters	3.937×10^{1}	miles
millimeters	1.094×10^{-3}	yards
million gal/day	1.54723	cu feet/sec
mils	2.54×10^{-3}	cm
mils	8.333×10^{-5}	feet
mils	1.0×10^{-3}	in.
mils	2.54×10^{-8}	km
mils	2.778×10^{-5}	yards
minims (British)	5.9192×10^{-2}	cu cm
minims (U.S., fluid)	6.1612×10^{-2}	cu cm
minutes (angles)	1.667×10^{-2}	degrees
minutes (angles)	1.852×10^{-4}	quadrants
minutes (angles)	2.909×10^{-4}	radians
minutes (angles)	6.0×10^{1}	seconds
minutes (time)	9.9206×10^{-5}	weeks
minutes (time)	6.944×10^{-4}	days
minutes (time)	1.667×10^{-2}	hr
minutes (time)	6.0×10^{1}	sec
myriagrams	1.0×10^{1}	kg
myriameters	1.0×10^{1}	km
myriawatts	1.0×10^{1}	kilowatts
N		
nails	2.25	in.
newtons	1.0 × 105	dynes
O		
ohm (international)	1.0005	ohm (absolute)
ohms	1.0×10^{-6}	megohms
ohms	1.0×10^{6}	microhms

ounces	8.0	drams
ounces	4.375×10^{2}	grains
ounces	2.8349×10^{1}	grams
ounces	6.25×10^{-2}	lb
ounces	9.115×10^{-1}	ounces (troy)
ounces	2.790×10^{-5}	tons (long)
ounces	3.125×10^{-5}	tons (short)
ounces (fluid)	1.805	cu in.
ounces (fluid)	2.957×10^{-2}	liters
ounces (troy)	4.80×10^{2}	grains
ounces (troy)	3.1103×10^{1}	grams
ounces (troy)	1.097	ounces (avdp.)
ounces (troy)	2.0×10^{1}	pennyweights (troy)
ounces (troy)	8.333×10^{-2}	lb (troy)
ounce/sq in.	4.309×10^{3}	dynes/sq cm
ounce/sq in.	6.25×10^{-2}	lb/sq in.
P		
pace	3.0×10^{1}	in.
parsec	1.9×10^{13}	miles
parsec	3.084×10^{13}	km
parts/million	5.84×10^{-2}	grains/U.S. gal
parts/million	7.016×10^{-2}	grains/Imp. gal
parts/million	8.345	lb/million gal
pecks (British)	5.546×10^{2}	cu in.
pecks (British)	9.0919	liters
pecks (U.S.)	2.5×10^{-1}	bushels
pecks (U.S.)	5.376×10^{2}	cu in.
pecks (U.S.)	8.8096	liters
pecks (U.S.)	8.0	quarts (dry)
pennyweights (troy)	2.4×10^{1}	grains
pennyweights (troy)	5.0×10^{-2}	ounces (troy)
pennyweights (troy)	1.555	grams

pennyweights (troy)	4.1667×10^{-3}	lb (troy)
pints (dry)	3.36×10^{1}	cu in.
pints (dry)	1.5625×10^{-2}	bushels
pints (dry)	5.0×10^{-1}	quarts
pints (dry)	5.5059×10^{-1}	liters
pints (liquid)	4.732×10^{2}	cu cm
pints (liquid)	1.671×10^{-4}	cu feet
pints (liquid)	2.887×10^{1}	cu in.
pints (liquid)	4.732×10^{-4}	cu meters
pints (liquid)	6.189×10^{-4}	cu yards
pints (liquid)	1.25×10^{-1}	gal
pints (liquid)	4.732×10^{-1}	liters
pints (liquid)	5.0×10^{-1}	quarts (liquid)
planck's quantum	6.624×10^{27}	erg-sec
poise	1.0	gram/cm-sec
lb (avdp.)	1.4583×10^{1}	ounces (troy)
poundals	1.3826×10^{4}	dynes
poundals	1.41×10^{1}	grams
poundals	1.383×10^{-3}	joules/cm
poundals	1.383×10^{-1}	joules/meter (newtons)
poundals	1.41×10^{-2}	kg
poundals	3.108×10^{-2}	lb
pounds	2.56×10^{2}	drams
pounds	4.448×10^{5}	dynes
pounds	7.0×10^{3}	grains
pounds	4.5359×10^{2}	grams
pounds	4.448×10^{-2}	joules/cm
pounds	4.448	joules/meter (newtons)
pounds	4.536×10^{-1}	kg
pounds	1.6×10^{1}	ounces
pounds	1.458×10^{1}	ounces (troy)
pounds	3.217×10^{1}	poundals

pounds	1.21528	lb (troy)
pounds	5.0×10^{-4}	tons (short)
pounds (troy)	5.760×10^{3}	grains
pounds (troy)	3.7324×10^{2}	grams
pounds (troy)	1.3166×10^{1}	ounces (avdp.)
pounds (troy)	1.2×10^{1}	ounces (troy)
pounds (troy)	2.4×10^{2}	pennyweights (troy)
pounds (troy)	8.2286×10^{-1}	lb (avdp.)
pounds (troy)	3.6735×10^{-4}	tons (long)
pounds (troy)	3.7324×10^{-4}	tons (metric)
pounds (troy)	4.1143×10^{-4}	tons (short)
pounds of water	1.602×10^{-2}	cu feet
pounds of water	2.768×10^{1}	cu in.
pounds of water	1.198×10^{-1}	gal
pounds of water/min	2.670×10^{-4}	cu feet/sec
pound-feet	1.356×10^{7}	cm-dynes
pound-feet	1.3825×10^{4}	cm-grams
pound-feet	1.383×10^{-1}	meter-kg
pounds/cu foot	1.602×10^{-2}	grams/cu cm
pounds/cu foot	1.602×10^{-2}	kg/cu meter
pounds/cu foot	5.787×10^{1}	lb/cu in.
pounds/cu toot	5.456×10^{-9}	lb/mil-foot
pounds/cu in.	2.768×10^{1}	grams/cu cm
pounds/cu in.	2.768×10^{4}	kg/cu meter
pounds/cu in.	1.728×10^{3}	lb/cu feet
pounds/cu in.	9.425×10^{-6}	lb/mil-foot
pounds/foot	1.488	kg/meter
pounds/in.	1.786×10^{2}	grams/cm
pounds/mil-foot	2.306×10^{6}	grams/cu cm
pounds/sq foot	4.725×10^{-4}	atmospheres
pounds/sq foot	1.602×10^{-4}	feet of water
pounds/sq foot	1.414×10^{2}	in. of mercury

pounds/sq foot	4.882	kg/sq meter
pounds/sq foot	6.944×10^{-3}	lb/sq in.
pounds/sq foot	7.02×10^{-2}	kg/sq cm
pounds/sq in.	6.804×10^{-2}	atmospheres
pounds/sq in.	2.307	feet of water
pounds/sq in.	2.036	in. of mercury
pounds/sq in.	7.031×10^{2}	kg/sq meter
pounds/sq in.	1.44×10^{2}	lb/sq foot
pounds/sq in.	7.2×10^{-2}	short tons/sq foot
Q		
quadrants (angle)	5.4×10^{3}	minutes
quadrants	1.571	radians
quadrants (angle)	3.24×10^{5}	seconds
quarts (dry)	6.72×10^{1}	cu in.
quarts (liquid)	9.464×10^{2}	cu c m
quarts (liquid)	3.342×10^{-2}	cu feet
quarts (liquid)	5.775×10^{1}	cu in.
quarts (liquid)	9.464×10^{-4}	cu meters
quarts (liquid)	1238×10^{-3}	cu yards
quarts (liquid)	2.5×10^{-1}	gal
quarts (liquid)	9.463×10^{-1}	liters
R		
radians	5.7296×10^{1}	degrees
radians	3.438×10^{3}	minutes
radians	6.366×10^{-1}	quadrants
radians	2.063×10^{5}	seconds
radians/sec	5.7296×10^{1}	degrees/sec
radians/sec	9.549	rev/min
radians/sec	1.592×10^{-1}	rev/sec
radians/sec/sec	5.7296×10^{2}	rev/min/min
radians/sec/sec	9.549	rev/min/sec
radians/sec/sec	1.592×10^{-1}	rev/sec/sec

reams	5.0×10^{2}	sheets
revolutions	3.60×10^{2}	degrees
revolutions	4.0	quadrants
revolutions	6.283	radians
revolutions/min	6.0	degrees/sec
revolutions/min	1.047×10^{-1}	radians/sec
revolutions/min	1.667×10^{-2}	rev/sec
rev/min/min	1.745×10^{-3}	radians/sec/sec
rev/min/min	1.667×10^{-2}	rev/min/sec
rev/min/min	2.778×10^{-4}	rev/sec/sec
revolutions/sec	3.6×10^{2}	degrees/sec
revolutions/sec	6.283	radians/sec
revolutions/sec	6.0×10^{1}	rev/min
rev/sec/sec	6.283	radians/sec/sec
rev/sec/sec	3.6×10^{3}	rev/min/min
rev/sec/sec	6.0×10^{1}	rev/min/sec
rods	5.029	meters
rod (surveyors' meas.)	5.5	yards
rods	1.65×10^{1}	feet
rods	1.98×10^{2}	in.
rods	3.125×10^{-3}	miles
S		
seconds (angle)	2.778×10^{-4}	degrees
seconds (angle)	1.667×10^{-2}	minutes
seconds (angle)	3.087×10^{-6}	quadrants
seconds (angle)	4.848×10^{-6}	radians
square cm	1.973×10^{5}	circular mils
square cm	1.076 × 10-3	sq feet
square cm	1.550×10^{-1}	sq in.
square cm	1.0×10^{-4}	sq meters
square cm	3.861×10^{-11}	sq miles
square cm	1.0×10^{2}	sq mm

square cm	1.196×10^{-4}	sq yards
square feet	2.296×10^{3}	acres
square feet	1.833×10^{3}	circular mils
square feet	9.29×10^{2}	sq cm
square feet	1.44×10^{2}	sq in.
square feet	9.29×10^{-2}	sq meters
square feet	3.587×10^{8}	sq miles
square feet	9.29×10^{4}	sq mm
square feet	1.111×10^{-1}	sq yards
square in.	1.273×10^{6}	circular mils
square in.	6.452	sq cm
square in.	6.944×10^{-3}	sq feet
square in.	6.452×10^{2}	sq mm
square in.	1.0×10^{6}	sq mils
square in.	7.716×10^{-4}	sq yards
square km	2.471×10^{2}	acres
square km	1.0×10^{10}	sq cm
square km	1.076×10^{7}	sq feet
square km	1.550×10^{9}	sq in.
square km	1.0×10^{6}	sq meters
square km	3.861×10^{-1}	sq miles
square km	1.196×10^{6}	sq yards
square meters	2.471×10^{-4}	acres
square meters	1.0×10^{4}	sq cm
square meters	1.076×10^{1}	sq feet
square meters	1.55×10^{3}	sq in.
square meters	3.861×10^{-7}	sq miles
square meters	1.0×10^{6}	sq mm
square meters	1.196	sq yards
square miles	6.40×10^{2}	acres
square miles	2.778×10^{7}	sq feet
square miles	2.590	sq km

square miles	2.590×10^{6}	sq meters
square miles	3.098×10^{6}	sq yards
square mm	1.973×10^{3}	circular mils
square mm	1.0×10^{-3}	sq cm
square mm	1.076×10^{-5}	sq feet
square mm	1.55×10^{-3}	sq in.
square yards	2.066×10^{-4}	acres
square yards	8.361×10^{3}	sq cm
square yards	9.0	sq feet
square yards	1.296×10^{3}	sq in.
square yards	8.361×10^{-1}	sq meters
square yards	3.228×10^{-7}	sq miles
square yards	8.361×10^{5}	sq mm
T		
Temperature °C + 273 °C + 17.78 °F + 460 °F – 32	1.0 1.8 1.0 0.5556	absolute Kelvin (°K) °Fahrenheit (°F) absolute Rankine (°R) °Celsius (°C)
tons (long)	1.016×10^{3}	kg
tons (long)	2.24×10^{3}	lb
tons (long)	1.1	tons (short)
tons (metric)	1.0×10^{3}	kg
tons (metric)	2.205×10^{3}	lb
tons (short)	9.0718×10^{2}	kg
tons (short)	3.2×10^{4}	ounces
tons (short)	2.9166×10^{4}	ounces (troy)
tons (short)	2.0×10^{3}	lb
tons (short)	2.43×10^{3}	lb (troy)
tons (short)	8.9287×10^{-1}	tons (long)
tons (short)	9.078×10^{-1}	tons (metric)
tons (short)/sq feet	9.765×10^{3}	kg/sq meter

tons (short)/sq feet	1.389×10^{1}	lb/sq in.
tons (short)/sq in.	1.406×10^{6}	kg/sq meter
tons (short)/sq in.	2.0×10^{3}	lb/sq in.
tons of water/24 hr	8.333×10^{1}	lb of water/hr
tons of water/24 hr	1.6643×10^{-1}	gal/min
tons of water/24 hr	1.3349	cu feet/hr
V		
volt/in.	3.937×10^{7}	abvolts/cm
volt/in.	3.937×10^{-1}	volt/cm
volt (absolute)	3.336 × 10-3	statvolts
volts	1.0×10^{3}	abvolts
W		
watts	3.4129	Btu/hr
watts	5.688×10^{-2}	Btu/min
watts	1.0×10^{7}	ergs/sec
watts	4.427×10^{1}	foot-lb/min
watts	7.378×10^{1}	foot-lb/sec
watts	1.341×10^{-1}	horsepower
watts	1.36×10^{-3}	horsepower (metric)
watts	1.433×10^{-2}	kg-calories/min
watts	1.0×10^{-3}	kilowatts
watts (abs.)	1.0	joules/sec
watt-hr	3.413	Btu
watt-hr	3.6×10^{10}	ergs
watt-hr	2.656×10^{3}	foot-lb
watt-hr	8.605×10^{2}	gram-calories
watt-hr	1.341×10^{-3}	horsepower-hr
watt-hr	8.605×10^{-1}	kg-calories
watt-hr	3.672×10^{2}	kg-meters
watt-hr	1.0×10^{-3}	kilowatt-hr
watt (international)	1.000165	watt (absolute)
weeks	1.68×10^{2}	hr

weeks	1.008×10^4	min
weeks	6.048×10^5	sec
Y		
yards	9.144×10^1	cm
yards	9.144×10^{-4}	km
yards	9.144×10^{-1}	meters
yards	4.934×10^{-4}	miles (nautical)
yards	5.682×10^{-4}	miles (statute)
yards	9.144×10^2	mm
years	3.65256×10^2	days (mean solar)
years	8.7661×10^3	hr (mean solar)

Useful Physical Constants

Gas Constants

R = 0.0821	(atm) (liter)/(g-mole) (°K)
R = 1.987	g-calories/(g-mole) (°K)
R = 1.987	Btu/(lb-mole) (°R)
R = 1.987	c.h.u./(lb-mole) (°K)
R = 8.314	joules/(g-mole) (°K)
R = 1546	(feet) (lb-force)/(lb-mole) (°R)
R = 10.73	(lb-force/sq in.) (cu feet)/(lb-mole) (°R)
R = 18,510	(lb-force/sq in.) (cu in.)/(lb-mole) (°R)
R = 0.7302	(atm) (cu feet)/(lb-mole) (°R)
$R = 8.48 \times 10^5$	(kg/m^2) (cu cm)/(lb-mole) (°K)

where

R = Gas Constant
°R = degrees Rankine
°K = degrees Kelvin

Acceleration of Gravity (Standard)

$g = 32.17\ ft/sec^2 = 980.6\ cm/sec^2$

Velocity of Sound in Dry Air @ 0°C and 1.0 atm

33,136 cm/sec = 1089 ft/sec

Heat of Fusion of Water

79.7 calories/g = 144 Btu/lb

Heat of Vaporization of Water @ 1.0 atm

540 calories/g = 970 Btu/lb

Specific Heat of Air

Cp = 0.238 calories/(g) (°C)

Density of Dry Air @ 0°C and 760 mm

0.001293 g/cu cm

Metric “SI” Conversions

Metric “SI” Unit Conversion Table

Property	Traditional Unit	Recommended "SI Unit"	Symbol	Conversion Factor	Example
Mechanical Properties					
Depth	feet	meter	m	0.3048	10,000 ft = 3048 m
Hole diameter	inch	millimeter	mm	25.4	12¼ in. = 311 mm
Pipe diameter	inch	millimeter	mm	25.4	4½ in. = 114 mm
Bit size	inch	millimeter	mm	25.4	12¼ in. = 311 mm
Weight on bit	pound	newton	N	4.4	20,000 lb = 88,000 N
Rotary table speed	rpm	*rev. per minute	r/min	1	45 rpm = 45 r/min
Nozzle size	$^1/_{32}$ inch	millimeter	mm	0.79	$^{10}/_{32}$ in. = 7.9 mm
Nozzle velocity	feet/sec	meter/sec	m/s	0.3048	400 ft/sec = 122 m/s
Drilling rate	feet/hour	*meter/hour	m/h	0.3048	30 ft/h = 9 m/h
Volume	barrels	cubic meter	m^3	0.159	3000 bbl = 477 m^3
Liner size	inch	millimeter	mm	25.4	6½ in. = 165 mm
Rod diameter	inch	millimeter	mm	25.4	2¼ in. = 57 mm
Stroke length	inch	millimeter	mm	25.4	16 in. = 406 mm
Pump output	barrel/minute or	*cubic meter/min	m^3/min	0.159	8.5 bbl/mm = 1.35 m^3/min
	gallon/minute	*cubic meter/min	m^3/min	0.00378	357 gpm = 1.35 m^3/min
Pump pressure	pound/sq inch	kilopascal	kPa	6.9	2500 psi= 17,300 kPa
Armular velocity,	feet/min	*meter/minute	m/min	0.3048	200 ft/min = 61 m/min
Slip velocity	feet/min	*meter/minute	m/min	0.3048	20 ft/min = 6.1 m/min
Temperature	degree Farenheit	degree Celsius	°C	(°F–32) ÷ 1.8	80°F = 27°C
	degree Centigrade	degree Celsius	°C	1.0	
Funnel viscosity	seconds/quart	seconds/liter	s/L	*Units cannot*	*normally be converted*
	seconds/1000cm^3	seconds/liler	s/L	1.0	

Metric “SI” Unit Conversion Table (continued)

Property	Traditional Unit	Recommended "SI Unit"	Symbol	Conv. Factor	Example
Fluid weight	pounds/gallon	kilogram/cubic meter	kg/m^3	120	10 lb/gal = 1200 kg/m^3
	pounds/ft^3	kilogram/cubic meter	kg/m^3	1.6	74.8 lb/ft^3 = 1200 kg/m^3
Pressure gradient	psi/ft	kilopascal/meter	kPa/m	22.6	0.52 psi/ft = 11.8 kPa/m
Hydrostatic head	psi	kilopascal	kPa	6.9	4000 psi = 27,600 kPa
Shear stress	lb$_f$ /100 ft^2	pascal	Pa	0.48	20 lb$_f$ /100 ft^2 = 960 Pa
	dynes/cm^2	pascal	Pa	0.100	1.0 dynes/cm^2 = 1.0 Pa
Shear rate	reciprocal second	reciprocal second	s^{-1}	1.0	
Apparent, plastic & effective viscosity	*centipoise	*centipoise	cP		
Yield point	lb$_f$ /100 ft^2	pascal	Pa	0.48	15 lb$_f$ /100 ft^2 = 7.2 Pa
Gel strength	lb$_f$ /100 ft^2	pascal	Pa	0.48	3 lb$_f$ /100ft^2 = 1.44 Pa
Dial reading	lb$_f$ /100 ft^2	pascal	Pa	0.51	dial reading -10 = 5.1 Pa
Standard V-G meter	1.065				
Power law constants					
n	dimensionless				
K	dynes s^n/cm^2	millipascal seconds^n/ square centimeter	mPa.s^n/cm^2	100	10 dynes s^n/cm^2 = 100 mPa s^n/cm^2
	lb$_f$ /s^n/100 ft^2	millipascal seconds^n/ square centimeter	mPa.s^n/cm^2	479	1.2 lb$_f$ s^n/100 ft^2 = 575 mPa s^n/cm^2
API filtrate	cubic centimeter/ 30 min	*cubic centimeter/ 30 min	cm^3/30 min		

Metric “SI” Unit Conversion Table (continued)

Property	Traditional Unit	Recommended "SI Unit"	Symbol	Conv. Factor	Example
Filter cake	$^1/_{32}$ inch	millimeter	mm	0.8	$^3/_{32}$ in = 2.4 mm
Sand, solid, oil, & water content	Volume percent	cubic meter/cubic meter	m^3/m^3	0.01	10 %= 0.1 m^3/m^3
Particle size	micron	micrometer	µm	1.0	
Chemical Properties					
Ionic concentration	grains/gallon	*milligram/liter	mg/L	17.1	500 grains/gal = 8600 mg/L
	parts/million	*milligram/liter	mg/L	× specific gravity	100,000 ppm of NaCl × 1.070 = 107,070 mg/L
Alkalinity P$_f$, M$_f$, P1, P2	cubic centimeter/ cubic centimeter	cubic centimeter/ cubic centimeter	cm^3/cm^3		
MBT Methylene Blue Content	cubic centimeter/ cubic centimeter	cubic centimeter/ cubic centimeter	cm^3/cm^3		
Miscellaneous					
Additive concentration	pound/barrel	kilogram/cubic meter	kg/m^3	2.85	10 lb$_m$/bbl = 28.5 kg/m^3
Corrosion rate	lb/ft/yr	kilogram/square meter/year	kg/m^2/yr	4.9	87 lb/ft^2/yr = 426 kg/m^2/yr
	mils/year	millimeter/year	mm/yr	0.0254	200 mils/year = 5.08 mm/yr
Bemonite yield	barrels/U.S. ton	*cu meter/metric ton	m^3/t	0.175	100 bbl/ton = 17.5 m^3/t
Hydraulic HP	horsepower	kilowatt	kw	0.746	600 hhp = 450 kw

Metric “SI” Unit Conversion Table (continued)

Property	Traditional Unit	Recommended "SI Unit"	Symbol	Conv. Factor	Example
Screen Size					
Mesh	openings/inch	openings/centimeter	openings/cm	0.254	100 mesh = 25.4 openings/cm
Aperature	micron	micrometer	µm	1.0	
Open area	area percent	square meter/square meter	m^2/m^2	0.01	30% = 0.3 m^2/m^2
Weight of drillpipe	pound/foot	kilogram/meter	kg/m	1.49	19.5 lb/ft = 29.1 kg/m
Oil Fluids					
Oil content	volume percent	cubic meter/cubic meter	m^3/m^3	0.01	10% = 0.1 m^3/m^3
Water content	volume percent	cubic meter/cubic meter	m^3/m^3	0.01	10% = 0.1 m^3/m^3
Emulsion stability	volts	volts	V		
Activity	dimensionless				
Salinity	ppm	*milligrams/liter	mg/L	specific gravity	250,000 ppm of $CaC1_2$ × 1.24 = 310,000 mg/L
Aniline point	degree Fahrenheit	degree Celsius	°C	$\frac{(°F - 32)}{1.8}$	150°F = 66°C

*Denotes acceptable deviation from API 2564 preferred unit.