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Formulas and Calculations for Drilling, Production, and Workover

All the Formulas You Need to Solve Drilling and Production Problems

Norton J. Lapeyrouse

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and
Calculations for Drilling, Production, and Workover

Second Edition

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CONTENTS

PREFACE

Over the last several years, hundreds of oilfield personnel have told me that they have enjoyed this book. Some use it as a secondary reference source; others use it as their primary source for formulas and calculations; still others use it to reduce the volume of materials they must carry to the rig floor or job site.

Regardless of the reason people use it, the primary purpose of the book is to provide a convenient source of reference to those people who don't use formulas and calculations on a regular basis.

In the preface to the first edition, I made reference to a driller who carried a briefcase full of books with him each time he went to the rig floor. I also mentioned a drilling supervisor who carried two briefcases of books. This book should reduce the number of books each of them needs to perform his job.

This book is still intended to serve oilfield workers for the entirety of their careers. I have added several formulas and calculations, some in English field units and some in Metric units. I have also added the Volumetric Procedure, the Lubricate and Bleed Procedure (both Volume and Pressure Method), and stripping procedures (both the Strip and Bleed Procedure and the Combined Stripping and Volumetric Procedure).

This book has been designed for convenience. It will occupy very little space in anyone's briefcase. It has a spiral binding so it will lay flat and stay open on a desk. The Table of Contents and the Index make looking up formulas and calculations quick and easy. Examples are used throughout to make the formulas as easy as possible to understand and work, and often exact words are used rather than symbols.

This book is dedicated to the thousands of oilfield hands worldwide who have to use formulas and calculations, whether on a daily basis or once or twice a year, and who have problems remembering them. This book should make their jobs a little easier.

CHAPTER ONE

BASIC FORMULAS

Pressure Gradient

Pressure gradient, psi/ft, using mud weight, ppg

psi/ft = mud weight, ppg $\times$ 0.052

Example: 12.0 ppg fluid

psi/ft = 12.0 ppg $\times$ 0.052
psi/ft = 0.624

Pressure gradient, psi/ft, using mud weight, lb/ft^3

psi/ft = mud weight, lb/ft^3 $\times$ 0.006944

Example: 100 lb/ft^3 fluid

psi/ft = 100 lb/ft^3 $\times$ 0.006944
psi/ft = 0.6944

OR

psi/ft = mud weight, lb/ft^3 $\div$ 144

Example: 100 lb/ft^3 fluid

psi/ft = 100 lb/ft^3 $\div$ 144
psi/ft = 0.6944

Pressure gradient, psi/ft, using mud weight, specific gravity (SG)

psi/ft = mud weight, SG $\times$ 0.433

Example: 1.0 SG fluid

psi/ft = 1.0 SG $\times$ 0.433
psi/ft = 0.433

Metric calculations

Pressure gradient, bar/m = drilling fluid density kg/l × 0.0981
Pressure gradient, bar/10m = drilling fluid density kg/l × 0.981

S.I. units calculations

Pressure gradient, kPa/m = drilling fluid density, kg/m^3 ÷ 102

Convert pressure gradient, psi/ft, to mud weight, ppg

ppg = pressure gradient, psi/ft ÷ 0.052

Example: 0.4992 psi/ft

ppg = 0.4992 psi/ft ÷ 0.052
ppg = 9.6

Convert pressure gradient, psi/ft, to mud weight, lb/ft^3

lb/ft^3 = pressure gradient, psi/ft ÷ 0.006944

Example: 0.6944 psi/ft

lb/ft^3 = 0.6944psi/ft ÷ 0.006944
lb/ft^3 = 100

Convert pressure gradient, psi/ft, to mud weight, SG

SG = pressure gradient, psi/ft ÷ 0.433

Example: 0.433 psi/ft

SG = 0.433psi/ft ÷ 0.433
SG = 1.0

Metric calculations

Drilling fluid density, kg/l = pressure gradient, bar/m ÷ 0.0981
Drilling fluid density, kg/l = pressure gradient, bar/10m ÷ 0.981

S.I. units calculations

Drilling fluid density, kg/m^3 = pressure gradient, kPa/m × 102

Hydrostatic Pressure (HP)

Hydrostatic pressure using ppg and feet as the units of measure

HP = mud weight, ppg × 0.052 × true vertical depth (TVD), ft

Example: mud weight = 13.5 ppg
true vertical depth = 12,000 ft

HP = 13.5 ppg × 0.052 × 12,000 ft
HP = 8424 psi

Hydrostatic pressure, psi, using pressure gradient, psi/ft

HP = psi/ft × true vertical depth, ft

Example: pressure gradient = 0.624 psi/ft
true vertical depth = 8500 ft

HP = 0.624 psi/ft × 8500 ft
HP = 5304 psi

Hydrostatic pressure, psi, using mud weight, lb/ft^3

HP = mud weight, lb/ft^3 × 0.006944 × TVD, ft

Example: mud weight = 90 lb/ft^3
true vertical depth = 7500 ft

HP = 90 lb/ft^3 × 0.006944 × 7500 ft
HP = 4687 psi

Hydrostatic pressure, psi, using meters as unit of depth

HP = mud weight, ppg × 0.052 × TVD, m × 3.281

Example: mud weight = 12.2 ppg
true vertical depth = 3700 meters

HP = 12.2 ppg × 0.052 × 3700 × 3.281
HP = 7701 psi

Metric calculations

$$\text{Hydrostatic pressure, bar} = \text{drilling fluid density, kg/l} \times 0.0981 \times \text{true vertical depth, m}$$

S.I. units calculations

$$\text{Hydrostatic pressure, kPa} = \frac{\text{drilling fluid density, kg/m}^3}{102} \times \text{true vertical depth, m}$$

Converting Pressure into Mud Weight

Convert pressure, psi, into mud weight, ppg, using feet as the unit of measure

Mud weight, ppg = pressure, psi ÷ 0.052 ÷ TVD, ft

Example: pressure = 2600 psi
true vertical depth = 5000 ft

Mud, ppg = 2600 psi ÷ 0.052 ÷ 5000 ft
Mud = 10.0 ppg

Convert pressure, psi, into mud weight, ppg, using meters as the unit of measure

Mud weight, ppg = pressure, psi ÷ 0.052 ÷ TVD, m ÷ 3.281

Example: pressure = 3583 psi
true vertical depth = 2000 meters

Mud wt, ppg = 3583 psi ÷ 0.052 ÷ 2000 m ÷ 3.281
Mud wt = 10.5 ppg

Metric calculations

$$\text{Equivalent drilling fluid density, kg/l} = \text{pressure, bar} \div 0.0981 \div \text{true vertical depth, m}$$

S.I. units calculations

$$\text{Equivalent drilling fluid density, kg/m}^3 = \text{pressure, kPa} \times 102 \div \text{true vertical depth, m}$$

Specific Gravity (SG)

Specific gravity using mud weight, ppg

SG = mud weight, ppg ÷ 8.33

Example: 15.0 ppg fluid

SG = 15.0 ppg ÷ 8.33
SG = 1.8

Specific gravity using pressure gradient, psi/ft

SG = pressure gradient, psi/ft ÷ 0.433

Example: pressure gradient = 0.624 psi/ft

SG = 0.624 psi/ft ÷ 0.433
SG = 1.44

Specific gravity using mud weight, lb/ft^3

SG = mud weight, lb/ft^3 ÷ 62.4

Example: mud weight = 120 lb/ft^3

SG = 120 lb/ft^3 ÷ 62.4
SG = 1.92

Convert specific gravity to mud weight, ppg

Mud weight, ppg = specific gravity × 8.33

Example: specific gravity = 1.80

Mud wt, ppg = 1.80 × 8.33
Mud wt = 15.0 ppg

Convert specific gravity to pressure gradient, psi/ft

psi/ft = specific gravity × 0.433

Example: specific gravity = 1.44

psi/ft = 1.44 × 0.433
psi/ft = 0.624

Convert specific gravity to mud weight, lb/ft^3

lb/ft^3 = specific gravity × 62.4

Example: specific gravity = 1.92

lb/ft^3 = 1.92 × 62.4
lb/ft^3 = 120

Equivalent Circulating Density (ECD), ppg

$$\text{ECD, ppg} = \begin{pmatrix}\text{annular}\\ \text{pressure}\\ \text{loss, psi}\end{pmatrix} \div 0.052 \div \text{TVD, ft} + \begin{pmatrix}\text{mud weight,}\\ \text{in use, ppg}\end{pmatrix}$$

Example: annular pressure loss = 200 psi
true vertical depth = 10,000 ft
mud weight = 9.6 ppg

ECD, ppg = 200 psi ÷ 0.052 ÷ 10,000 ft + 9.6 ppg
ECD = 10.0 ppg

Metric calculation

$$\text{Equivalent drilling fluid density, kg/l} = \text{annular pressure loss, bar} \div 0.0981 \div \text{TVD, m} + \text{mud wt, kg/l}$$

S.I. units calculations

$$\text{Equivalent circulating density, kg/l} = \frac{\text{annular pressure loss, kPa} \times 102}{\text{TVD, m}} + \text{mud density, kg/m}$$

Maximum Allowable Mud Weight from Leak-off Test Data

$$\text{ppg} = \begin{pmatrix}\text{leak-off} \\ \text{pressure, psi}\end{pmatrix} \div 0.052 \div \begin{pmatrix}\text{casing shoe} \\ \text{TVD, ft}\end{pmatrix} + \begin{pmatrix}\text{mud weight,} \\ \text{ppg}\end{pmatrix}$$

Example: leak-off test pressure = 1140 psi
casing shoe TVD = 4000 ft
mud weight = 10.0 ppg

ppg = 1140 psi ÷ 0.052 ÷ 4000 ft + 10.0 ppg
ppg = 15.48

Pump Output (PO)

Triplex Pump

Formula 1

$$\text{PO, bbl/stk} = 0.000243 \times \begin{pmatrix}\text{liner} \\ \text{diameter, in.}\end{pmatrix}^2 \times \begin{pmatrix}\text{stroke} \\ \text{length, in.}\end{pmatrix}$$

Example: Determine the pump output, bbl/stk, at 100% efficiency for a 7-in. by 12-in. triplex pump:

PO @ 100% = 0.000243 × 7^2 × 12
PO @ 100% = 0.142884 bbl/stk

Adjust the pump output for 95% efficiency:

Decimal equivalent = 95 ÷ 100 = 0.95

PO @ 95% = 0.142884 bbl/stk × 0.95
PO @ 95% = 0.13574 bbl/stk

Formula 2

$$\text{PO, gpm} = [3(D^2 \times 0.7854)S]\,0.00411 \times \text{SPM}$$

where D = liner diameter, in.
S = stroke length, in.
SPM = strokes per minute

Example: Determine the pump output, gpm, for a 7-in. by 12-in. triplex pump at 80 strokes per minute:

$$\text{PO, gpm} = [3(7^2 \times 0.7854)12]\,0.00411 \times 80$$
$$\text{PO, gpm} = 1385.4456 \times 0.00411 \times 80$$
$$\text{PO} = 455.5\,\text{gpm}$$

Duplex Pump

Formula 1

$$0.000324 \times \begin{pmatrix}\text{liner}\\ \text{diameter, in.}\end{pmatrix}^2 \times \begin{pmatrix}\text{stroke}\\ \text{length, in.}\end{pmatrix} = \_\_\_\_\_\_\_ \ \text{bbl/stk}$$

$$-0.000162 \times \begin{pmatrix}\text{rod}\\ \text{diameter, in.}\end{pmatrix}^2 \times \begin{pmatrix}\text{stroke}\\ \text{length, in.}\end{pmatrix} = \_\_\_\_\_\_\_ \ \text{bbl/stk}$$

$$\text{pump output @ 100\% eff} = \_\_\_\_\_\_\_ \ \text{bbl/stk}$$

Example: Determine the output, bbl/stk, of a 5-1/2 in. by 14-in. duplex pump at 100% efficiency. Rod diameter = 2.0 in.:

$$0.000324 \times 5.5^2 \times 14 = 0.137214\,\text{bbl/stk}$$
$$-0.000162 \times 2.0^2 \times 14 = \underline{0.009072}\,\text{bbl/stk}$$
$$\text{Pump output @ 100\% eff} = 0.128142\,\text{bbl/stk}$$

Adjust pump output for 85% efficiency:

Decimal equivalent = 85 ÷ 100 = 0.85

PO @ 85% = 0.128142 bbl/stk × 0.85
PO @ 85% = 0.10892 bbl/stk

Formula 2

$$\text{PO, bbl/stk} = 0.000162 \times S\left[2(D)^2 - d^2\right]$$

where S = stroke length, in.
D = liner diameter, in.
d = rod diameter, in.

Example: Determine the output, bbl/stk, of a 5-1/2-in. by 14-in. duplex pump @ 100% efficiency. Rod diameter = 2.0 in.:

$$\text{PO @ } 100\% = 0.000162 \times 14 \times \left[2\,(5.5)^2 - 2^2\right]$$
$$\text{PO @ } 100\% = 0.000162 \times 14 \times 56.5$$
$$\text{PO @ } 100\% = 0.128142\ \text{bbl/stk}$$

Adjust pump output for 85% efficiency:

PO @ 85% = 0.128142 bbl/stk × 0.85
PO @ 85% = 0.10892 bbl/stk

Metric calculation

Pump output, liter/min = pump output, liter/stk × pump speed, spm

S.I. units calculation

Pump output, m^3/min = pump output, liter/stk × pump speed, spm

Annular Velocity (AV)

Annular velocity (AV), ft/min

Formula 1

AV = pump output, bbl/min ÷ annular capacity, bbl/ft

Example: pump output = 12.6 bbl/min
annular capacity = 0.1261 bbl/ft

$$AV = 12.6\,\text{bbl/min} \div 0.1261\,\text{bbl/ft}$$
$$AV = 99.92\,\text{ft/min}$$

Formula 2

$$AV,\ \text{ft/min} = \frac{24.5 \times Q}{Dh^2 - Dp^2}$$

where Q = circulation rate, gpm
Dh = inside diameter of casing or hole size, in.
Dp = outside diameter of pipe, tubing or collars, in.

Example: pump output = 530 gpm
hole size = 12-1/4 in.
pipe OD = 4-1/2 in.

$$AV = \frac{24.5 \times 530}{12.25^2 - 4.5^2}$$

$$AV = \frac{12{,}985}{129.8125}$$

$$AV = 100\,\text{ft/min}$$

Formula 3

$$AV,\ \text{ft/min} = \frac{PO,\ \text{bbl/min} \times 1029.4}{Dh^2 - Dp^2}$$

Example: pump output = 12.6 bbl/min
hole size = 12-1/4 in.
pipe OD = 4-1/2 in.

$$AV = \frac{12.6\,\text{bbl/min} \times 1029.4}{12.25^2 - 4.5^2}$$

$$AV = \frac{12970.44}{129.8125}$$

$$AV = 99.92\,\text{ft/min}$$

Annular velocity (AV), ft/sec

$$AV,\ ft/sec = \frac{17.16 \times PO,\ bbl/min}{Dh^2 - Dp^2}$$

Example: pump output = 12.6 bbl/min
hole size = 12-1/4 in.
pipe OD = 4-1/2 in.

$$AV = \frac{17.16 \times 12.6\,bbl/min}{12.25^2 - 4.5^2}$$

$$AV = \frac{216.216}{129.8125}$$

$$AV = 1.6656\,ft/sec$$

Metric calculations

Annular velocity, m/min = pump output, liter/min ÷ annular volume, l/m

Annular velocity, m/sec = pump output, liter/min ÷ 60 ÷ annular volume, l/m

S.I. units calculations

Annular velocity, m/min = pump output, m^3/min ÷ annular volume, m^3/m

Pump output, gpm, required for a desired annular velocity, ft/min

$$\text{Pump output, gpm} = \frac{AV,\ ft/min\,(Dh^2 - DP^2)}{24.5}$$

where AV = desired annular velocity, ft/min
Dh = inside diameter of casing or hole size, in.
Dp = outside diameter of pipe, tubing or collars, in.

Example: desired annular velocity = 120 ft/min
hole size = 12-1/4 in.
pipe OD = 4-1/2 in.

$$PO = \frac{120\,(12.25^2 - 4.5^2)}{24.5}$$

$$PO = \frac{120 \times 129.8125}{24.5}$$

$$PO = \frac{15{,}577.5}{24.5}$$

$$PO = 635.8\,\text{gpm}$$

Strokes per minute (SPM) required for a given annular velocity

$$SPM = \frac{\text{annular velocity, ft/min} \times \text{annular capacity, bbl/ft}}{\text{pump output, bbl/stk}}$$

Example: annular velocity = 120 ft/min
annular capacity = 0.1261 bbl/ft
Dh = 12-1/4 in.
Dp = 4-1/2 in.
pump output = 0.136 bbl/stk

$$SPM = \frac{120\,\text{ft/min} \times 0.1261\,\text{bbl/ft}}{0.136\,\text{bbl/stk}}$$

$$SPM = \frac{15.132}{0.136}$$

$$SPM = 111.3$$

Capacity Formulas

Annular capacity between casing or hole and drill pipe, tubing, or casing

a) $$\text{Annular capacity, bbl/ft} = \frac{Dh^2 - Dp^2}{1029.4}$$

Example: Hole size (Dh) = 12-1/4 in.
Drill pipe OD (Dp) = 5.0 in.

$$\text{Annular capacity, bbl/ft} = \frac{12.25^2 - 5.0^2}{1029.4}$$

$$\text{Annular capacity} = 0.12149\,\text{bbl/ft}$$

b) Annular capacity, ft/bbl $= \dfrac{1029.4}{(Dh^2 - Dp^2)}$

Example: Hole size (Dh) = 12-1/4 in.
Drill pipe OD (Dp) = 5.0 in.

Annular capacity, ft/bbl $= \dfrac{1029.4}{(12.25^2 - 5.0^2)}$

Annular capacity = 8.23 ft/bbl

c) Annular capacity, gal/ft $= \dfrac{Dh^2 - Dp^2}{24.51}$

Example: Hole size (Dh) = 12-1/4 in.
Drill pipe OD (Dp) = 5.0 in.

Annular capacity, gal/ft $= \dfrac{12.25^2 - 5.0^2}{24.51}$

Annular capacity = 5.1 gal/ft

d) Annular capacity, ft/gal $= \dfrac{24.51}{(Dh^2 - Dp^2)}$

Example: Hole size (Dh) = 12-1/4 in.
Drill pipe OD (Dp) = 5.0 in.

Annular capacity, ft/gal $= \dfrac{24.51}{(12.25^2 - 5.0^2)}$

Annular capacity = 0.19598 ft/gal

e) Annular capacity, ft^3/linft $= \dfrac{Dh^2 - Dp^2}{183.35}$

Example: Hole size (Dh) = 12-1/4 in.
Drill pipe OD (Dp) = 5.0 in.

Annular capacity, ft^3/linft $= \dfrac{12.25^2 - 5.0^2}{183.35}$

Annular capacity = 0.682097 ft^3/linft

f) Annular capacity, linft/ft^3 $= \dfrac{183.35}{(Dh^2 - Dp^2)}$

Example: Hole size (Dh) = 12-1/4 in.
Drill pipe OD (Dp) = 5.0 in.

$$\text{Annular capacity, linft/ft}^3 = \frac{183.35}{(12.25^2 - 5.0^2)}$$

$$\text{Annular capacity} = 1.466\,\text{linft/ft}^3$$

Annular capacity between casing and multiple strings of tubing

a) Annular capacity between casing and multiple strings of tubing, bbl/ft:

$$\text{Annular capacity, bbl/ft} = \frac{Dh^2 - \left[(T_1)^2 + (T_2)^2\right]}{1029.4}$$

Example: Using two strings of tubing of same size:

Dh	= casing—7.0 in.—29 lb/ft	ID = 6.184 in.
T_1	= tubing No. 1—2-3/8 in.	OD = 2.375 in.
T_2	= tubing No. 2—2-3/8 in.	OD = 2.375 in.

$$\text{Annular capacity, bbl/ft} = \frac{6.184^2 - (2.375^2 + 2.375^2)}{1029.4}$$

$$\text{Annular capacity, bbl/ft} = \frac{38.24 - 11.28}{1029.4}$$

$$\text{Annular capacity} = 0.02619\,\text{bbl/ft}$$

b) Annular capacity between casing and multiple strings of tubing, ft/bbl:

$$\text{Annular capacity, ft/bbl} = \frac{1029.4}{Dh^2 - \left[(T_1)^2 + (T_2)^2\right]}$$

Example: Using two strings of tubing of same size:

Dh	= casing—7.0 in.—29 lb/ft	ID = 6.184 in.
T_1	= tubing No. 1—2-3/8 in.	OD = 2.375 in.
T_2	= tubing No. 2—2-3/8 in.	OD = 2.375 in.

$$\text{Annular capacity, ft/bbl} = \frac{1029.4}{6.184^2 - (2.375^2 + 2.375^2)}$$

$$\text{Annular capacity, ft/bbl} = \frac{1029.4}{38.24 - 11.28}$$

$$\text{Annular capacity} = 38.1816\,\text{ft/bbl}$$

c) Annular capacity between casing and multiple strings of tubing, gal/ft:

$$\text{Annular capacity, gal/ft} = \frac{Dh^2 - \left[(T_1)^2 + (T_2)^2\right]}{24.51}$$

Example: Using two tubing strings of different size:

Dh	= casing—7.0 in.—29 lb/ft	ID = 6.184 in.
T_1	= tubing No. 1—2-3/8 in.	OD = 2.375 in.
T_2	= tubing No. 2—3-1/2 in.	OD = 3.5 in.

$$\text{Annular capacity, gal/ft} = \frac{6.184^2 - (2.375^2 + 3.5^2)}{24.51}$$

$$\text{Annular capacity, gal/ft} = \frac{38.24 - 17.89}{24.51}$$

$$\text{Annular capacity} = 0.8302733\,\text{gal/ft}$$

d) Annular capacity between casing and multiple strings of tubing, ft/gal:

$$\text{Annular capacity, ft/gal} = \frac{24.51}{Dh^2 - \left[(T_1)^2 + (T_2)^2\right]}$$

Example: Using two tubing strings of different sizes:

Dh	= casing—7.0 in.—29 lb/ft	ID = 6.184 in.
T_1	= tubing No. 1—2-3/8 in.	OD = 2.375 in.
T_2	= tubing No. 2—3-1/2 in.	OD = 3.5 in.

$$\text{Annular capacity, ft/gal} = \frac{24.51}{6.184^2 - (2.375^2 + 3.5^2)}$$

$$\text{Annular capacity, ft/gal} = \frac{24.51}{38.24 - 17.89}$$

$$\text{Annular capacity} = 1.2044226\,\text{ft/gal}$$

e) Annular capacity between casing and multiple strings of tubing, ft³/linft:

$$\text{Annular capacity, ft}^3\text{/linft} = \frac{Dh^2 - \left[(T_1)^2 + (T_2)^2\right]}{183.35}$$

Example: Using three strings of tubing:

Dh	= casing—9-5/8 in.—47 lb/ft	ID = 8.681 in.
T_1	= tubing No. 1—3-1/2 in.	OD = 3.5 in.
T_2	= tubing No. 2—3-1/2 in.	OD = 3.5 in.
T_3	= tubing No. 3—3-1/2 in.	OD = 3.5 in.

$$\text{Annular capacity} = \frac{8.681^2 - (3.5^2 + 3.5^2 + 3.5^2)}{183.35}$$

$$\text{Annular capacity, ft}^3\text{/linft} = \frac{183.35}{75.359 - 36.75}$$

$$\text{Annular capacity} = 0.2105795\ \text{ft}^3\text{/linft}$$

f) Annular capacity between casing and multiple strings of tubing, linft/ft³:

$$\text{Annular capacity, linft/ft}^3 = \frac{183.35}{Dh^2 - \left[(T_1)^2 + (T_2)^2\right]}$$

Example: Using three strings tubing of same size:

Dh	= casing—9-5/8 in.—47 lb/ft	ID = 8.681 in.
T_1	= tubing No. 1—3-1/2 in.	OD = 3.5 in.
T_2	= tubing No. 2—3-1/2 in.	OD = 3.5 in.
T_3	= tubing No. 3—3-1/2 in.	OD = 3.5 in.

$$\text{Annular capacity} = \frac{183.35}{8.681^2 - (3.5^2 + 3.5^2 + 3.5^2)}$$

$$\text{Annular capacity, linft/ft}^3 = \frac{183.35}{75.359 - 36.75}$$

$$\text{Annular capacity} = 4.7487993\ \text{linft/ft}^3$$

Capacity of tubulars and open hole: drill pipe, drill collars, tubing, casing, hole, and any cylindrical object

a) $\text{Capacity, bbl/ft} = \dfrac{\text{ID, in.}^2}{1029.4}$

Example: Determine the capacity, bbl/ft, of a 12-1/4 in. hole:

$$\text{Capacity, bbl/ft} = \frac{12.25^2}{1029.4}$$

$$\text{Capacity} = 0.1457766\,\text{bbl/ft}$$

b) $$\text{Capacity, ft/bbl} = \frac{1029.4}{\text{Dh}^2}$$

Example: Determine the capacity, ft/bbl, of 12-1/4 in. hole:

$$\text{Capacity, ft/bbl} = \frac{1029.4}{12.25^2}$$

$$\text{Capacity} = 6.8598\,\text{ft/bbl}$$

c) $$\text{Capacity, gal/ft} = \frac{\text{ID, in.}^2}{24.51}$$

Example: Determine the capacity, gal/ft, of 8-1/2 in. hole:

$$\text{Capacity, gal/ft} = \frac{8.5^2}{24.51}$$

$$\text{Capacity} = 2.9477764\,\text{gal/ft}$$

d) $$\text{Capacity, ft/gal} = \frac{24.51}{\text{ID, in.}^2}$$

Example: Determine the capacity, ft/gal, of 8-1/2 in. hole:

$$\text{Capacity, ft/gal} = \frac{24.51}{8.5^2}$$

$$\text{Capacity} = 0.3392\,\text{ft/gal}$$

e) $$\text{Capacity, ft}^3\text{/linft} = \frac{\text{ID}^2}{183.35}$$

Example: Determine the capacity, ft^3/linft, for a 6.0 in. hole:

$$\text{Capacity, ft}^3\text{/linft} = \frac{6.0^2}{183.35}$$

Capacity = $0.1963\,ft^3/linft$

f) $\text{Capacity, linft/ft}^3 = \dfrac{183.35}{\text{ID, in.}^2}$

Example: Determine the capacity, linft/ft^3, for a 6.0 in. hole:

$$\text{Capacity, linft/ft}^3 = \frac{183.35}{6.0^2}$$

Capacity = $5.09305\,linft/ft^3$

Amount of cuttings drilled per foot of hole drilled

a) BARRELS of cuttings drilled per foot of hole drilled:

$$\text{Barrels} = \frac{Dh^2}{1029.4}(1 - \%\,\text{porosity})$$

Example: Determine the number of barrels of cuttings drilled for one foot of 12-1/4 in.-hole drilled with 20% (0.20) porosity:

$$\text{Barrels} = \frac{12.25^2}{1029.4}(1 - 0.20)$$

$$\text{Barrels} = 0.1457766 \times 0.80$$

$$\text{Barrels} = 0.1166213$$

b) CUBIC FEET of cuttings drilled per foot of hole drilled:

$$\text{Cubic feet} = \frac{Dh^2}{144} \times 0.7854\,(1 - \%\,\text{porosity})$$

Example: Determine the cubic feet of cuttings drilled for one foot of 12-1/4 in. hole with 20% (0.20) porosity:

$$\text{Cubic feet} = \frac{12.25^2}{144} \times 0.7854\,(1 - 0.20)$$

$$\text{Cubic feet} = \frac{150.0626}{144} \times 0.7854 \times 0.80$$

$$\text{Cubic feet} = 0.6547727$$

c) Total solids generated:

$$W_{cg} = 350\ Ch \times L\ (1 - P)\ SG$$

where W_{cg} = solids generated, pounds
Ch = capacity of hole, bbl/ft
L = footage drilled, ft
SG = specific gravity of cuttings
P = porosity, %

Example: Determine the total pounds of solids generated in drilling 100 ft of a 12-1/4 in. hole (0.1458 bbl/ft). Specific gravity of cuttings = 2.40 gm/cc. Porosity = 20%.

$$W_{cg} = 350 \times 0.1458 \times 100\,(1 - 0.20) \times 2.4$$

$$W_{cg} = 9797.26 \text{ pounds}$$

Control Drilling

Maximum drilling rate (MDR), ft/hr, when drilling large diameter holes (14-3/4 in. and larger)

$$\text{MDR, ft/hr} = \frac{67 \times \left(\begin{matrix}\text{mud wt} \\ \text{out, ppg}\end{matrix} - \begin{matrix}\text{mud wt} \\ \text{in, ppg}\end{matrix}\right) \times \left(\begin{matrix}\text{circulation} \\ \text{rate, gpm}\end{matrix}\right)}{Dh^2}$$

Example: Determine the MDR, ft/hr, necessary to keep the mud weight coming out at 9.7 ppg at the flow line:

Data: Mud weight in = 9.0 ppg
Circulation rate = 530 gpm
Hole size = 17-1/2 in.

$$\text{MDR, ft/hr} = \frac{67\,(9.7 - 9.0)\,530}{17.5^2}$$

$$\text{MDR, ft/hr} = \frac{67 \times 0.7 \times 530}{306.25}$$

$$\text{MDR, ft/hr} = \frac{24{,}857}{306.25}$$

$$\text{MDR} = 81.16 \text{ ft/hr}$$

Buoyancy Factor (BF)

Buoyancy factor using mud weight, ppg

$$BF = \frac{65.5 - \text{mud weight, ppg}}{65.5}$$

Example: Determine the buoyancy factor for a 15.0 ppg fluid:

$$BF = \frac{65.5 - 15.0}{65.5}$$

$$BF = 0.77099$$

Buoyancy factor using mud weight, lb/ft³

$$BF = \frac{489 - \text{mud weight, lb/ft}^3}{489}$$

Example: Determine the buoyancy factor for a 120 lb/ft³ fluid:

$$BF = \frac{489 - 120}{489}$$

$$BF = 0.7546$$

Hydrostatic Pressure (HP) Decrease When Pulling Pipe out of the Hole

When pulling DRY pipe

Step 1

$$\text{Barrels displaced} = \text{number of stands pulled} \times \text{average length per stand, ft} \times \text{pipe displacement bbl/ft}$$

Step 2

$$\text{HP, psi decrease} = \frac{\text{barrels displaced}}{\left(\text{casing capacity, bbl/ft} - \text{pipe displacement, bbl/ft}\right)} \times 0.052 \times \text{mud weight, ppg}$$

Example: Determine the hydrostatic pressure decrease when pulling DRY pipe out of the hole:

Number of stands pulled = 5
Average length per stand = 92 ft
Pipe displacement = 0.0075 bbl/ft
Casing capacity = 0.0773 bbl/ft
Mud weight = 11.5 ppg

Step 1

$$\text{Barrels displaced} = 5 \text{ stands} \times 92\,\text{ft/std} \times 0.0075\,\text{bbl/ft}$$

$$\text{Barrels displaced} = 3.45$$

Step 2

$$\text{HP, psi decrease} = \frac{3.45 \text{ barrels}}{\begin{pmatrix} 0.0773 & - & 0.0075 \\ \text{bbl/ft} & & \text{bbl/ft} \end{pmatrix}} \times 0.052 \times 11.5\,\text{ppg}$$

$$\text{HP, psi decrease} = \frac{3.45 \text{ barrels}}{0.0698} \times 0.052 \times 11.5\,\text{ppg}$$

$$\text{HP decrease} = 29.56\,\text{psi}$$

When pulling WET pipe

Step 1

$$\text{Barrels displaced} = \begin{matrix}\text{number} \\ \text{of stands} \\ \text{pulled}\end{matrix} \times \begin{matrix}\text{average} \\ \text{length per} \\ \text{stand, ft}\end{matrix} \times \begin{pmatrix}\text{pipe disp., bbl/ft} \\ + \\ \text{pipe cap., bbl/ft}\end{pmatrix}$$

Step 2

$$\textbf{HP, psi} = \frac{\text{barrels displaced}}{\begin{pmatrix}\text{casing} \\ \text{capacity,} \\ \text{bbl/ft}\end{pmatrix} - \begin{pmatrix}\text{pipe disp., bbl/ft} \\ + \\ \text{pipe cap., bbl/ft}\end{pmatrix}} \times 0.052 \times \begin{matrix}\text{mud} \\ \text{weight, ppg}\end{matrix}$$

Example: Determine the hydrostatic pressure decrease when pulling WET pipe out of the hole:

Number of stands pulled = 5
Average length per stand = 92 ft
Pipe displacement = 0.0075 bbl/ft
Pipe capacity = 0.01776 bbl/ft
Casing capacity = 0.0773 bbl/ft
Mud weight = 11.5 ppg

Step 1

$$\text{Barrels displaced} = 5 \text{ stands} \times 92 \text{ ft/std} \times \begin{pmatrix} 0.0075 \text{ bbl/ft} \\ + \\ 0.01776 \text{ bbl/ft} \end{pmatrix}$$

$$\text{Barrels displaced} = 11.6196$$

Step 2

$$\text{HP, psi decrease} = \frac{11.6196 \text{ barrels}}{\begin{pmatrix} 0.0773 \\ \text{bbl/ft} \end{pmatrix} - \begin{pmatrix} 0.0075 \text{ bbl/ft} \\ + \\ 0.01776 \text{ bbl/ft} \end{pmatrix}} \times 0.052 \times 11.5 \text{ ppg}$$

$$\text{HP, psi decrease} = \frac{11.6196}{0.05204} \times 0.052 \times 11.5 \text{ ppg}$$

$$\text{HP decrease} = 133.52 \text{ psi}$$

Loss of Overbalance Due to Falling Mud Level

Feet of pipe pulled DRY to lost overbalance

$$\text{Feet} = \frac{\text{overbalance, psi (casing cap.} - \text{pipe disp., bbl/ft)}}{\text{mud wt., ppg} \times 0.052 \times \text{pipe disp., bbl/ft}}$$

Example: Determine the FEET of DRY pipe that must be pulled to lose the overbalance using the following data:

Amount of overbalance = 150 psi
Casing capacity = 0.0773 bbl/ft
Pipe displacement = 0.0075 bbl/ft
Mud weight = 11.5 ppg

$$\text{Ft} = \frac{150\text{psi}\ (0.0773 - 0.0075)}{11.5\text{ppg} \times 0.052 \times 0.0075}$$

$$\text{Ft} = \frac{10.47}{0.004485}$$

$$\text{Ft} = 2334$$

Feet of pipe pulled WET to lose overbalance

$$\text{Feet} = \frac{\text{overbalance, psi} \times (\text{casing cap.} - \text{pipe cap.} - \text{pipe disp.})}{\text{mud wt., ppg} \times 0.052 \times (\text{pipe cap.} + \text{pipe disp., bbl/ft})}$$

Example: Determine the feet of WET pipe that must be pulled to lose the overbalance using the following data:

Amount of overbalance = 150 psi
Casing capacity = 0.0773 bbl/ft
Pipe capacity = 0.01776 bbl/ft
Pipe displacement = 0.0075 bbl/ft
Mud weight = 11.5 ppg

$$\text{Feet} = \frac{150\text{psi} \times (0.0073 - 0.01776 - 0.0075\text{bbl/ft})}{11.5\text{ppg} \times 0.052\ (0.01776 + 0.0075\text{bbl/ft})}$$

$$\text{Feet} = \frac{150\ \text{psi} \times 0.05204}{11.5\ \text{ppg} \times 0.052 \times 0.02526}$$

$$\text{Feet} = \frac{7.806}{0.0151054}$$

$$\text{Feet} = 516.8$$

Metric calculations

$$\text{Pressure drop per meter tripping dry pipe, bar/m} = \frac{\text{drilling fluid density, kg/l} \times \text{metal displacement, l/m} \times 0.0981}{\text{casing capacity, l/m} - \text{metal displacement, l/m}}$$

$$\text{Pressure drop per meter tripping dry pipe, bar/m} = \frac{\text{drilling fluid density, bar/m} \times \text{metal displacement, l/m} \times 0.0981}{\text{casing capacity, l/m} - \text{metal displacement, l/m}}$$

$$\text{Pressure drop per meter tripping wet pipe, bar/m} = \frac{\text{drilling fluid density, kg/l} \times \begin{pmatrix}\text{metal disp., l/m} \\ + \\ \text{pipe capacity, l/m}\end{pmatrix} \times 0.0981}{\text{annular capacity, l/m}}$$

$$\text{Pressure drop per meter tripping wet pipe, bar/m} = \frac{\text{drilling fluid density, bar/m} \times \begin{pmatrix}\text{metal disp., l/m} \\ + \\ \text{pipe capacity, l/m}\end{pmatrix}}{\text{annular capacity, l/m}}$$

$$\text{Level drop for POOH drill collars} = \frac{\text{length of drill collars, m} \times \text{metal disp., l/m}}{\text{casing capacity, l/m}}$$

S.I. units calculations

$$\text{Pressure drop per meter tripping dry pipe, kPa/m} = \frac{\text{drilling fluid density, kg/m}^3 \times \text{metal disp., m}^3\text{/m}}{\left(\text{casing capacity, m}^3\text{/m} - \text{metal disp., m}^3\text{/m}\right) \times 102}$$

$$\text{Pressure drop per meter tripping wet pipe, kPa/m} = \frac{\text{drilling fluid density, kg/m}^3 \times \begin{pmatrix}\text{metal disp., m}^3\text{/m} \\ + \\ \text{pipe capacity, m}^3\text{/m}\end{pmatrix}}{\text{annular capacity, m}^3\text{/m} \times 102}$$

$$\text{Level drop for POOH drill collars, m} = \frac{\text{length of drill collars, m} \times \text{metal disp., m}^3\text{/m}}{\text{casing capacity, m}^3\text{/m}}$$

Formation Temperature (FT)

$$\text{FT, °F} = \begin{pmatrix}\text{ambient} \\ \text{surface} \\ \text{temperature, °F}\end{pmatrix} + \begin{pmatrix}\text{temperature} \\ \text{increase °F per ft of depth} \times \text{TVD, ft}\end{pmatrix}$$

Example: If the temperature increase in a specific area is 0.012°F/ft of depth and the ambient surface temperature is 70°F, determine the estimated formation temperature at a TVD of 15,000 ft:

FT, °F = 70°F + (0.012°F/ft × 15,000 ft)
FT, °F = 70°F + 180°F
FT = 250°F (estimated formation temperature)

Hydraulic Horsepower (HHP)

$$HHP = \frac{P \times Q}{1714}$$

where HHP = hydraulic horsepower
P = circulating pressure, psi
Q = circulating rate, gpm

Example: circulating pressure = 2950 psi
circulating rate = 520 gpm

$$HHP = \frac{2950 \times 520}{1714}$$

$$HHP = \frac{1,534,000}{1714}$$

HHP = 894.98

Drill Pipe/Drill Collar Calculations

Capacities, bbl/ft, displacement, bbl/ft, and weight, lb/ft, can be calculated from the following formulas:

$$\text{Capacity, bbl/ft} = \frac{\text{ID, in.}^2}{1029.4}$$

$$\text{Displacement, bbl/ft} = \frac{\text{OD, in.}^2 - \text{ID, in.}^2}{1029.4}$$

Weight, lb/ft = displacement, bbl/ft × 2747 lb/bbl

Example: Determine the capacity, bbl/ft, displacement, bbl/ft, and weight, lb/ft, for the following:

Drill collar OD = 8.0 in.
Drill collar ID = 2-13/16 in.

Convert 13/16 to decimal equivalent:

$13 \div 16 = 0.8125$

a) Capacity, bbl/ft $= \dfrac{2.8125^2}{1029.4}$

Capacity = 0.007684 bbl/ft

b) Displacement, bbl/ft $= \dfrac{8.0^2 - 2.8125^2}{1029.4}$

Displacement, bbl/ft $= \dfrac{56.089844}{1029.4}$

Displacement = 0.0544879 bbl/ft

c) Weight, lb/ft = 0.0544879 bbl/ft × 2747 lb/bbl
Weight = 149.678 lb/ft

Rule of thumb formulas

Weight, lb/ft, for REGULAR DRILL COLLARS can be approximated using the following formula:

Weight, lb/ft = (OD, in.^{2} − ID, in.^{2}) 2.66

Example: Regular drill collars

Drill collar OD = 8.0 in.
Drill collar ID = 2-13/16 in.
Decimal equivalent = 2.8125 in.

Weight, lb/ft = $(8.0^2 - 2.8125^2)$ 2.66
Weight, lb/ft = 56.089844 × 2.66
Weight = 149.19898 lb/ft

Weight, lb/ft, for SPIRAL DRILL COLLARS can be approximated using the following formula:

Weight, lb/ft = (OD, in.^{2} − ID, in.^{2}) 2.56

Example: Spiral drill collars

Drill collar OD = 8.0 in.
Drill collar ID = 2-13/16 in.
Decimal equivalent = 2.8125 in.

Weight, lb/ft = $(8.0^2 - 2.8125^2)\ 2.56$
Weight, lb/ft = 56.089844×2.56
Weight = 143.59 lb/ft

Pump Pressure/Pump Stroke Relationship (Also Called the Roughneck's Formula)

Basic formula

$$\text{New circulating pressure, psi} = \text{present circulating pressure, psi} \times \left(\frac{\text{new pump rate, spm}}{\text{old pump rate, spm}}\right)^2$$

Example: Determine the new circulating pressure, psi using the following data:

Present circulating pressure = 1800 psi
Old pump rate = 60 spm
New pump rate = 30 spm

$$\text{New circulating pressure, psi} = 1800\,\text{psi}\left(\frac{30\,\text{spm}}{60\,\text{spm}}\right)^2$$

$$\text{New circulating pressure, psi} = 1800\,\text{psi} \times 0.25$$

$$\text{New circulating pressure} = 450\,\text{psi}$$

Determination of exact factor in above equation

The above formula is an approximation because the factor "2" is a rounded-off number. To determine the exact factor, obtain two pressure readings at different pump rates and use the following formula:

$$\text{Factor} = \frac{\log\,(\text{pressure } 1 \div \text{pressure } 2)}{\log\,(\text{pump rate } 1 \div \text{pump rate } 2)}$$

Example: Pressure 1 = 2500 psi @ 315 gpm
Pressure 2 = 450 psi @ 120 gpm

$$\text{Factor} = \frac{\log(2500\,\text{psi} \div 450\,\text{psi})}{\log(315\,\text{gpm} \div 120\,\text{gpm})}$$

$$\text{Factor} = \frac{\log(5.5555556)}{\log(2.625)}$$

$$\text{Factor} = 1.7768$$

Example: Same example as above but with correct factor:

$$\text{New circulating pressure, psi} = 1800\,\text{psi}\left(\frac{30\,\text{spm}}{60\,\text{spm}}\right)^{1.7768}$$

$$\text{New circulating pressure, psi} = 1800\,\text{psi} \times 0.2918299$$

$$\text{New circulating pressure} = 525\,\text{psi}$$

Metric calculation

$$\text{new pump pressure with new pump strokes, bar} = \text{current pressure, bar} \times \left(\frac{\text{new SPM}}{\text{old SPM}}\right)^2$$

S.I. units calculation

$$\text{new pump pressure with new pump strokes, kPa} = \text{current pressure, kPa} \times \left(\frac{\text{new SPM}}{\text{old SPM}}\right)^2$$

Cost per Foot

$$C_T = \frac{B + C_R(t + T)}{F}$$

Example: Determine the drilling cost (C_T), dollars per foot, using the following data:

Bit cost (B)	= \$2500
Rig cost (C_R)	= \$900/hour
Rotating time (T)	= 65 hours
Round trip time (T)	= 6 hours
(for depth—10,000 ft)	
Footage per bit (F)	= 1300 ft

$$C_T = \frac{2500 + 900(65 + 6)}{1300}$$

$$C_T = \frac{66{,}400}{1300}$$

$$C_T = \$51.08 \text{ per foot}$$

Temperature Conversion Formulas

Convert temperature, °Fahrenheit (F) to °Centigrade or Celsius (C)

$$°C = \frac{(°F - 32)5}{9} \text{ OR } °C = °F - 32 \times 0.5556$$

Example: Convert 95 °F to °C:

$$°C = \frac{(95 - 32)5}{9} \text{ OR } °C = 95 - 32 \times 0.5556$$

$$°C = 35 \qquad\qquad °C = 35$$

Convert temperature, °Centigrade or Celsius (C) to °Fahrenheit

$$°F = \frac{(°C \times 9)}{5} + 32 \text{ OR } °F = °C \times 1.8 + 32$$

Example: Convert 24 °C to °F

$$°F = \frac{(24 \times 9)}{5} + 32 \text{ OR } °F = 24 \times 1.8 + 32$$

$$°F = 75.2 \qquad\qquad °F = 75.2$$

Convert temperature, °Centigrade, Celsius (C) to °Kelvin (K)

$$°K = °C + 273.16$$

Example: Convert 35 °C to °K:

$°K = 35 + 273.16$
$°K = 308.16$

Convert temperature, °Fahrenheit (F) to °Rankine (R)

$°R = °F + 459.69$

Example: Convert 260 °F to °R:

$°R = 260 + 459.69$
$°R = 719.69$

Rule of thumb formulas for temperature conversion

a) Convert °F to °C

$°C = °F - 30 \div 2$

Example: Convert 95 °F to °C:

$°C = 95 - 30 \div 2$
$°C = 32.5$

b) Convert °C to °F

$°F = °C + °C + 30$

Example: Convert 24 °C to °F:

$°F = 24 + 24 + 30$
$°F = 78$

CHAPTER TWO

BASIC CALCULATIONS

Volumes and Strokes

Drill string volume, barrels

$$\text{Barrels} = \frac{\text{ID, in.}^2}{1029.4} \times \text{pipe length, ft}$$

Annular volume, barrels

$$\text{Barrels} = \frac{\text{Dh, in.}^2 - \text{Dp, in.}^2}{1029.4}$$

Strokes to displace: drill string, annulus, and total circulation from kelly to shale shaker

Strokes = barrels ÷ pump output, bbl/stk

Example: Determine volumes and strokes for the following:

Drill pipe—5.0 in.—19.5 lb/ft
- Inside diameter = 4.276 in.
- Length = 9400 ft

Drill collars—8.0 in. OD
- Inside diameter = 3.0 in.
- Length = 600 ft

Casing—13-3/8 in.—54.5 lb/ft
- Inside diameter = 12.615 in.
- Setting depth = 4500 ft

Pump data—7 in. by 12 in. triplex
- Efficiency = 95%
- Pump output = 0.136 @ 95%

Hole size = 12-1/4 in.

Drill string volume

a) Drill pipe volume, bbl:

$$\text{Barrels} = \frac{4.276^2}{1029.4} \times 9400\,\text{ft}$$

$$\text{Barrels} = 0.01776 \times 9400\,\text{ft}$$

$$\text{Barrels} = 166.94$$

b) Drill collar volume, bbl:

$$\text{Barrels} = \frac{3.0^2}{1029.4} \times 600\,\text{ft}$$

$$\text{Barrels} = 0.0087 \times 600\,\text{ft}$$

$$\text{Barrels} = 5.24$$

c) Total drill string volume:

Total drill string vol, bbl = 166.94 bbl + 5.24 bbl

Total drill string vol = 172.18 bbl

Annular volume

a) Drill collar/open hole:

$$\text{Barrels} = \frac{12.25^2 - 8.0^2}{1029.4} \times 600\,\text{ft}$$

$$\text{Barrels} = 0.0836 \times 600\,\text{ft}$$

$$\text{Barrels} = 50.16$$

b) Drill pipe/open hole:

$$\text{Barrels} = \frac{12.25^2 - 5.0^2}{1029.4} \times 4900\,\text{f}$$

$$\text{Barrels} = 0.12149 \times 4900\,\text{ft}$$

$$\text{Barrels} = 595.3$$

c) Drill pipe/cased hole:

$$\text{Barrels} = \frac{12.615^2 - 5.0^2}{1029.4} \times 4500\,\text{ft}$$

Barrels = 0.130307 × 4500 ft

Barrels = 586.38

d) Total annular volume:

Total annular vol = 50.16 + 595.3 + 586.38
Total annular vol = 1231.84 barrels

Strokes

a) Surface-to-bit strokes:

Strokes = drill string volume, bbl ÷ pump output, bbl/stk

Surface-to-bit strokes = 172.16 bbl ÷ 0.136 bbl/stk

Surface-to-bit strokes = 1266

b) Bit-to-surface (or bottoms-up) strokes:

Strokes = annular volume, bbl ÷ pump output, bbl/stk

Bit-to-surface strokes = 1231.84 bbl ÷ 0.136 bbl/stk

Bit-to-surface strokes = 9058

c) Total strokes required to pump from the kelly to the shale shaker:

Strokes = drill string vol, bbl + annular vol, bbl ÷ pump output, bbl/stk

Total strokes = (172.16 + 1231.84) ÷ 0.136
Total strokes = 1404 ÷ 0.136
Total strokes = 10,324

Slug Calculations

Barrels of slug required for a desired length of dry pipe

Step 1

Hydrostatic pressure required to give desired drop inside drill pipe:

HP, psi = mud wt, ppg × 0.052 × ft of dry pipe

Step 2

Difference in pressure gradient between slug weight and mud weight:

$$\text{psi/ft} = (\text{slug wt, ppg} - \text{mud wt, ppg}) \times 0.052$$

Step 3

Length of slug in drill pipe:

$$\text{Slug length, ft} = \text{pressure, psi} \div \frac{\text{difference in}}{\text{pressure gradient, psi/ft}}$$

Step 4

Volume of slug, barrels:

$$\text{Slug vol, bbl} = \text{slug length, ft} \times \frac{\text{drill pipe}}{\text{capacity, bbl/ft}}$$

Example: Determine the barrels of slug required for the following:

Desired length of dry pipe (2 stands)	= 184 ft
Mud weight	= 12.2 ppg
Slug weight	= 13.2 ppg
Drill pipe capacity 4-1/2 in.—16.6 lb/ft	= 0.01422 bbl/ft

Step 1

Hydrostatic pressure required:

$$\text{HP, psi} = 12.2\,\text{ppg} \times 0.052 \times 184\,\text{ft}$$
$$\text{HP} = 117\,\text{psi}$$

Step 2

Difference in pressure gradient, psi/ft:

$$\text{psi/ft} = (13.2\text{ ppg} - 12.2\text{ ppg}) \times 0.052$$
$$\text{psi/ft} = 0.052$$

Step 3

Length of slug in drill pipe, ft:

$$\text{Slug length, ft} = 117\,\text{psi} \div 0.052$$
$$\text{Slug length} = 2250\,\text{ft}$$

Step 4

Volume of slug, bbl:

Slug vol, bbl = 2250 ft × 0.01422 bbl/ft
Slug vol = 32.0 bbl

Weight of slug required for a desired length of dry pipe with a set volume of slug

Step 1

Length of slug in drill pipe, ft:

Slug length, ft = slug vol, bbl ÷ drill pipe capacity, bbl/ft

Step 2

Hydrostatic pressure required to give desired drop inside drill pipe:

HP, psi = mud wt, ppg × 0.052 × ft of dry pipe

Step 3

Weight of slug, ppg:

Slug wt, ppg = HP, psi ÷ 0.052 ÷ slug length, ft + mud wt, ppg

Example: Determine the weight of slug required for the following:

Desired length of dry pipe (2 stands) = 184 ft
Mud weight = 12.2 ppg
Volume of slug = 25 bbl
Drill pipe capacity = 0.01422 bbl/ft
4-1/2 in.—16.6 lb/ft

Step 1

Length of slug in drill pipe, ft:

Slug length, ft = 25 bbl ÷ 0.01422 bbl/ft
Slug length = 1758 ft

Step 2

Hydrostatic pressure required:

HP, psi = 12.2 ppg × 0.052 × 184 ft
HP = 117 psi

Step 3

Weight of slug, ppg:

Slug wt, ppg = 117 psi ÷ 0.052 ÷ 1758 ft + 12.2 ppg
Slug wt, ppg = 1.3 ppg + 12.2 ppg
Slug wt = 13.5 ppg

Volume, height, and pressure gained because of slug:

a) Volume gained in mud pits after slug is pumped, due to U-tubing:

Vol, bbl = ft of dry pipe × drill pipe capacity, bbl/ft

b) Height, ft, that the slug would occupy in annulus:

Height, ft = annulus vol, ft/bbl × slug vol, bbl

c) Hydrostatic pressure gained in annulus because of slug:

$$\text{HP, psi} = \begin{matrix}\text{height of slug} \\ \text{in annulus, ft}\end{matrix} \times \begin{matrix}\text{difference in gradient, psi/ft} \\ \text{between slug wt and mud wt}\end{matrix}$$

Example: Feet of dry pipe (2 stands) = 184 ft
Slug volume = 32.4 bbl
Slug weight = 13.2 ppg
Mud weight = 12.2 ppg
Drill pipe capacity = 0.01422 bbl/ft
4-1/2 in.—16.6 lb/ft
Annulus volume (8-1/2 in. by 4-1/2 in.) = 19.8 ft/bbl

a) Volume gained in mud pits after slug is pumped due to U-tubing:

Vol, bbl = 184 ft × 0.01422 bbl/ft
Vol = 2.62 bbl

b) Height, ft, that the slug would occupy in the annulus:

Height, ft = 19.8 ft/bbl × 32.4 bbl
Height = 641.5 ft

c) Hydrostatic pressure gained in annulus because of slug:

HP, psi = 641.5 ft (13.2 − 12.2) × 0.052
HP, psi = 641.5 ft × 0.052
HP = 33.4 psi

English units calculation

Barrels gained pumping slug, bbl
= (bbl slug pumped × slug wt, ppg ÷ mud wt, ppg) − bbl slug

Example: Determine the number of barrels of mud gained due to pumping the slug and determine the feet of dry pipe.

Mud weight = 12.6 ppg
Slug weight = 14.2 ppg
Barrels of slug pumped = 25 barrels
Drill pipe capacity = 0.01776 bbl/ft

Barrels gained = (25 bbl × 14.2 ppg ÷ 12.6 ppg) − 25 bbl
= 28.175 − 25
= 3.175 bbl

Determine the feet of dry pipe after pumping the slug.

Feet of dry pipe = 3.175 bbl ÷ 0.01776 bbl/ft
= 179 feet

Metric calculation

liters gained pumping slug = (liter slug pumped × slug wt, kg/l ÷ mud wt, kg/l) − liter slug

S. I. units calculation

m^3 gained pumping slug = (m^3 slug pumped × slug wt, kg/m^3) − m^3 slug

Accumulator Capacity—Useable Volume per Bottle

Useable Volume per Bottle

NOTE: The following will be used as guidelines:

Volume per bottle = 10 gal
Pre-charge pressure = 1000 psi
Minimum pressure remaining after activation = 1200 psi
Pressure gradient of hydraulic fluid = 0.445 psi/ft
Maximum pressure = 3000 psi

Boyle's Law for ideal gases will be adjusted and used as follows:

$P_1V_1 = P_2V_2$

Surface application

Step 1

Determie hydraulic fluid necessary to increase pressure from pre-charge to minimum:

$P_1V_1 = P_2V_2$

$1000\,\text{psi} \times 10\,\text{gal} = 1200\,\text{psi} \times V_2$

$$\frac{10{,}000}{1200} = V_2$$

$V_2 = 8.33$ The nitrogen has been compressed from 10.0 gal to 8.33 gal.

$10.0 - 8.33 = 1.67$ gal of hydraulic fluid per bottle.

NOTE: This is dead hydraulic fluid. The pressure must not drop below this minimum value.

Step 2

Determine hydraulic fluid necessary to increase pressure from pre-charge to maximum:

$P_1V_1 = P_2V_2$

$1000\,\text{psi} \times 10\,\text{gals} = 3000\,\text{psi} \times V_2$

$$\frac{10{,}000}{3000} = V_2$$

$V_2 = 3.33$ The nitrogen has been compressed from 10 gal to 3.33 gal.

$10.0 - 3.33 = 6.67$ gal of hydraulic fluid per bottle.

Step 3

Determine useable volume per bottle:

$$\frac{\text{Useable}}{\text{vol/bottle}} = \frac{\text{Total hydraulic}}{\text{fluid/bottle}} - \frac{\text{Dead hydraulic}}{\text{fluid/bottle}}$$

Useable vol/bottle $= 6.67 - 1.67$

Useable vol/bottle $= 5.0\,\text{gallons}$

English units

$$\text{Volume delivered, gallons} = \text{bottle capacity, gals} \times \left(\frac{\text{precharge, psi}}{\text{final, psi}}\right) - \left(\frac{\text{precharge, psi}}{\text{system, psi}}\right)$$

Example: Determine the amount of usable hydraulic fluid delivered from a 20-gallon bottle:

Precharge pressure = 1000 psi
System pressure = 3000 psi
Final pressure = 1200 psi

$$\text{Volume delivered, gallons} = 20\,\text{gallons} \times \left(\frac{1000\,\text{psi}}{1200\,\text{psi}}\right) - \left(\frac{1000\,\text{psi}}{3000\,\text{psi}}\right)$$
$$= 20\text{ gallons} \times (0.833 - 0.333)$$
$$= 20\text{ gallons} \times 0.5$$
$$= 10\text{ gallons}$$

Subsea applications

In subsea applications the hydrostatic pressure exerted by the hydraulic fluid must be compensated for in the calculations:

Example: Same guidelines as in surface applications:

Water depth = 1000 ft
Hydrostatic pressure of hydraulic fluid = 445 psi

Step 1

Adjust all pressures for the hydrostatic pressure of the hydraulic fluid:

Pre-charge pressure = 1000 psi + 445 psi = 1445 psi
Minimum pressure = 1200 psi + 445 psi = 1645 psi
Maximum pressure = 3000 psi + 445 psi = 3445 psi

Step 2

Determine hydraulic fluid necessary to increase pressure from pre-charge to minimum:

$$P_1V_1 = P_2V_2$$

$$1445\,\text{psi} \times 10 = 1645 \times V_2$$

$$\frac{14{,}560}{1645} = V_2$$

$$V_2 = 8.78\,\text{gal}$$

$$10.0 - 8.78 = 1.22\,\text{gal of dead hydraulic fluid}$$

Step 3

Determine hydraulic fluid necessary to increase pressure from pre-charge to maximum:

$$1445\,\text{psi} \times 10 = 3445\,\text{psi} \times V_2$$

$$\frac{14{,}450}{3445} = V_2$$

$$V_2 = 4.19\,\text{gal}$$

$$10.0 - 4.19 = 5.81\,\text{gal of hydraulic fluid per bottle.}$$

Step 4

Determine useable fluid volume per bottle:

$$\begin{matrix}\text{Useable} \\ \text{vol/bottle}\end{matrix} = \begin{matrix}\text{total hydraulic} \\ \text{fluid/bottle}\end{matrix} - \begin{matrix}\text{dead hydraulic} \\ \text{fluid/bottle}\end{matrix}$$

$$\begin{matrix}\text{Useable} \\ \text{vol/bottle}\end{matrix} = 5.81 - 1.22$$

$$\begin{matrix}\text{Useable} \\ \text{vol/bottle}\end{matrix} = 4.59\,\text{gallons}$$

Accumulator pre-charge pressure

The following is a method of measuring the average accumulator pre-charge pressure by operating the unit with the charge pumps switched off:

$$P,\text{psi} = \frac{\text{vol removed, bbl}}{\text{total acc. vol, bbl}} \times \left(\frac{\text{Pf} \times \text{Ps}}{\text{Ps} - \text{Pf}}\right)$$

where P = average pre-charge pressure, psi
Pf = final accumulator pressure, psi
Ps = starting accumulator pressure, psi

Example: Determine the average accumulator pre-charge pressure using the following data:

Starting accumulator pressure (Ps) = 3000 psi
Final accumulator pressure (Pf) = 2200 psi
Volume of fluid removed = 20 gal
Total accumulator volume = 180 gal

$$P,\text{psi} = \frac{20}{180} \times \left(\frac{2200 \times 3000}{3000 - 2200}\right)$$

$$P,\text{psi} = 0.1111 \times \left(\frac{6{,}600{,}000}{800}\right)$$

$$P,\text{psi} = 0.1111 \times 8250$$

$$P = 917\,\text{psi}$$

Bulk Density of Cuttings (Using Mud Balance)

Procedure:

1. Cuttings must be washed free of mud. In an oil mud, diesel oil can be used instead of water.
2. Set mud balance at 8.33 ppg.
3. Fill the mud balance with cuttings until a balance is obtained with the lid in place.
4. Remove lid, fill cup with water (cuttings included), replace lid, and dry outside of mud balance.
5. Move counterweight to obtain new balance.

The specific gravity of the cuttings is calculated as follows:

$$SG = \frac{1}{2 - (0.12 \times \text{Rw})}$$

where SG = specific gravity of cuttings—bulk density
Rw = resulting weight with cuttings plus water, ppg

Example: Rw = 13.8 ppg. Determine the bulk density of cuttings:

$$SG = \frac{1}{2 - (0.12 \times 13.8)}$$

$$SG = \frac{1}{0.344}$$

$$SG = 2.91$$

Drill String Design (Limitations)

The following will be determined:

Length of bottomhole assembly (BHA) necessary for a desired weight on bit (WOB).

Feet of drill pipe that can be used with a specific bottomhole assembly (BHA).

1. Length of bottomhole assembly necessary for a desired weight on bit:

$$\text{Length, ft} = \frac{\text{WOB} \times f}{\text{Wdc} \times \text{BF}}$$

where WOB = desired weight to be used while drilling
f = safety factor to place neutral point in drill collars
Wdc = drill collar weight, lb/ft
BF = buoyancy factor

Example: Desired WOB while drilling = 50,000 lb
Safety factor = 15%
Mud weight = 12.0 ppg
Drill collar weight = 147 lb/ft
8 in. OD—3 in. ID

Solution: a) Buoyancy factor (BF):

$$BF = \frac{65.5 - 12.0\,\text{ppg}}{65.5}$$

$$BF = 0.8168$$

b) Length of bottomhole assembly necessary:

$$\text{Length, ft} = \frac{50{,}000 \times 1.15}{147 \times 0.8168}$$

$$\text{Length, ft} = \frac{57{,}500}{120.0696}$$

$$\text{Length} = 479\,\text{ft}$$

2. Feet of drill pipe that can be used with a specific bottomhole assembly (BHA)

NOTE: Obtain tensile strength for new pipe from cementing handbook or other source.

a) Determine buoyancy factor:

$$\text{BF} = \frac{65.5 - \text{mud weight, ppg}}{65.5}$$

b) Determine maximum length of drill pipe that can be run into the hole with a specific bottomhole assembly:

$$\text{Length}_{max} = \frac{[(T \times f) - \text{MOP} - \text{Wbha}] \times \text{BF}}{\text{Wdp}}$$

where T = tensile strength, lb for new pipe
f = safety factor to correct new pipe to no. 2 pipe
MOP = margin of overpull
Wbha = BHA weight in air, lb/ft
Wdp = drill pipe weight in air, lb/ft, including tool joint
BF = buoyancy factor

c) Determine total depth that can be reached with a specific bottomhole assembly:

Total depth, ft = length_{max} + BHA length

Example: Drill pipe (5.0 in.) = 21.87 lb/ft – Grade G
Tensile strength = 554,000 lb
BHA weight in air = 50,000 lb
BHA length = 500 ft
Desired overpull = 100,000 lb
Mud weight = 13.5 ppg
Safety factor = 10%

a) Buoyancy factor:

$$BF = \frac{65.5 - 13.5}{65.5}$$

$BF = 0.7939$

b) Maximum length of drill pipe that can be run into the hole:

$$Length_{max} = \frac{[(554{,}000 \times 0.90) - 100{,}000 - 50{,}000] \times 0.7639}{21.87}$$

$$Length_{max} = \frac{276{,}754}{21.87}$$

$Length_{max} = 12{,}655\,ft$

c) Total depth that can be reached with this BHA and this drill pipe:

Total depth, ft = 12,655 ft + 500 ft

Total depth = 13,155 ft

Ton-Mile (TM) Calculations

All types of ton-mile service should be calculated and recorded in order to obtain a true picture of the total service received from the rotary drilling line. These include:

1. Round trip ton-miles
2. Drilling or "connection" ton-miles
3. Coring ton-miles
4. Ton-miles setting casing
5. Short-trip ton-miles

Round trip ton-miles (RT_{TM})

$$RT_{TM} = \frac{Wp \times D \times (Lp + D) + (2 \times D)(2 \times Wb + Wc)}{5280 \times 2000}$$

where RT_{TM} = round trip ton-miles
Wp = buoyed weight of drill pipe, lb/ft
D = depth of hole, ft

Lp = length of one stand of drill pipe, (ave), ft
Wb = weight of traveling block assembly, lb
Wc = buoyed weight of drill collars in mud minus the buoyed weight of the same length of drill pipe, lb
2000 = number of pounds in one ton
5280 = number of feet in one mile

Example: Round trip ton-miles

Mud weight	= 9.6 ppg
Measured depth	= 4000 ft
Drill pipe weight	= 13.3 lb/ft
Drill collar weight	= 83 lb/ft
Drill collar length	= 300 ft
Traveling block assembly	= 15,000 lb
Average length of one stand	= 60 ft (double)

Solution: a) Buoyancy factor:

$$BF = 65.5 - 9.6\,\text{ppg.} \div 65.5$$
$$BF = 0.8534$$

b) Buoyed weight of drill pipe in mud, lb/ft (Wp):

$$Wp = 13.3\,\text{lb/ft} \times 0.8534$$
$$Wp = 11.35\,\text{lb/ft}$$

c) Buoyed weight of drill collars in mud minus the buoyed weight of the same length of drill pipe, lb (Wc):

$$Wc = (300 \times 83 \times 0.8534) - (300 \times 13.3 \times 0.8534)$$
$$Wc = 21{,}250 - 3405$$
$$Wc = 17{,}845\,\text{lb}$$

Round trip ton-miles =

$$\frac{11.35 \times 4000 \times (60 + 4000) + (2 \times 4000) \times (2 \times 15{,}000 + 17{,}845)}{5280 \times 2000}$$

$$RT_{TM} = \frac{11.35 \times 4000 \times 4060 + 8000 \times (30{,}000 + 17{,}845)}{5280 \times 2000}$$

$$RT_{TM} = \frac{11.35 \times 4000 \times 4060 + 8000 \times 47{,}845}{10{,}560{,}000}$$

$$RT_{TM} = \frac{1.8432 \quad 08 + 3.8276 \quad 08}{10{,}560{,}000}$$

$$RT_{TM} = 53.7$$

Drilling or "connection" ton-miles

The ton-miles of work performed in drilling operations is expressed in terms of work performed in making round trips. These are the actual ton-miles of work involved in drilling down the length of a section of drill pipe (usually approximately 30 ft) plus picking up, connecting, and starting to drill with the next section.

To determine connection or drilling ton-miles, take 3 times (ton-miles for current round trip minus ton-miles for previous round trip):

$$Td = 3(T_2 - T_1)$$

where Td = drilling or "connection" ton-miles
T_2 = ton-miles for one round trip—depth where drilling stopped before coming out of hole.
T_1 = ton-miles for one round trip—depth where drilling started.

Example: Ton-miles for trip @ 4600 ft = 64.6
Ton-miles for trip @ 4000 ft = 53.7

$$Td = 3 \times (64.6 - 53.7)$$
$$Td = 3 \times 10.9$$
$$Td = 32.7 \text{ ton-miles}$$

Ton-miles during coring operations

The ton-miles of work performed in coring operations, as for drilling operations, is expressed in terms of work performed in making round trips.

To determine ton-miles while coring, take 2 times ton-miles for one round trip at the depth where coring stopped minus ton-miles for one round trip at the depth where coring began:

$$Tc = 2(T_4 - T_3)$$

where Tc = ton-miles while coring
T_4 = ton-miles for one round trip—depth where coring stopped before coming out of hole
T_3 = ton-miles for one round trip—depth where coring started after going in hole

Ton-miles setting casing

The calculations of the ton-miles for the operation of setting casing should be determined as for drill pipe, but with the buoyed weight of the casing being used, and with the result being multiplied by one-half, because setting casing is a one-way (1/2 round trip) operation. Ton-miles for setting casing can be determined from the following formula:

$$Tc = \frac{Wp \times D \times (Lcs + D) + D \times Wb}{5280 \times 2000} \times 0.5$$

where Tc = ton-miles setting casing
Wp = buoyed weight of casing, lb/ft
Lcs = length of one joint of casing, ft
Wb = weight of traveling block assembly, lb

Ton-miles while making short trip

The ton-miles of work performed in short trip operations is also expressed in terms of round trips. Analysis shows that the ton-miles of work done in making a short trip is equal to the difference in round trip ton-miles for the two depths in question.

$$Tst = T_6 - T_5$$

where Tst = ton-miles for short trip
T_6 = ton-miles for one round trip at the deeper depth, the depth of the bit before starting the short trip.
T_5 = ton-miles for one round trip at the shallower depth, the depth that the bit is pulled up to.

Cementing Calculations

Cement additive calculations

a) Weight of additive per sack of cement:

Weight, lb = percent of additive × 94 lb/sk

b) Total water requirement, gal/sk, of cement:

$$\text{Water, gal/sk} = \begin{matrix}\text{Cement water} \\ \text{requirement, gal/sk}\end{matrix} + \begin{matrix}\text{Additive water} \\ \text{requirement, gal/sk}\end{matrix}$$

c) Volume of slurry, gal/sk:

$$\text{Vol gal/sk} = \frac{94\,\text{lb}}{\text{SG of cement} \times 8.33\,\text{lb/gal}}$$

$$+ \frac{\text{weight of additive, lb}}{\text{SG of additive} \times 8.33\,\text{lb/gal}}$$

$$+ \text{water volume, gal}$$

d) Slurry yield, ft^3/sk:

$$\text{Yield, ft}^3\text{/sk} = \frac{\text{vol of slurry, gal/sk}}{7.48\,\text{gal/ft}^3}$$

e) Slurry density, lb/gal:

$$\text{Density, lb/gal} = \frac{94 + \text{wt of additive} + (8.33 \times \text{vol of water/sk})}{\text{vol of slurry, gal/sk}}$$

Example: Class A cement plus 4% bentonite using normal mixing water:

Determine the following:

Amount of bentonite to add
Total water requirements
Slurry yield
Slurry weight

1) Weight of additive:

Weight, lb/sk = 0.04 × 94 lb/sk
Weight = 3.76 lb/sk

2) Total water requirement:

Water = 5.1 (cement) + 2.6 (bentonite)
Water = 7.7 gal/sk of cement

3) Volume of slurry:

$$\text{Vol, gal/sk} = \frac{94}{3.14 \times 8.33} + \frac{3.76}{2.65 \times 8.33} + 7.7$$

Vol, gal/sk = 3.5938 + 0.1703 + 7.7
Vol = 11.46 gal/sk

4) Slurry yield, ft^3/sk:

Yield, ft^3/sk = 11.46 gal/sk ÷ 7.48 gal/ft^3
Yield = 1.53 ft^3/sk

5) Slurry density, lb/gal:

$$\text{Density, lb/gal} = \frac{94 + 3.76 + (8.33 \times 7.7)}{11.46}$$

$$\text{Density, lb/gal} = \frac{161.90}{11.46}$$

Density = 14.13 lb/gal

Water requirements

a) Weight of materials, lb/sk:

Weight, lb/sk = 94 + (8.33 × vol of water, gal) + (% of additive × 94)

b) Volume of slurry, gal/sk:

$$\text{Vol, gal/sk} = \frac{94\text{ lb/sk}}{SG \times 8.33} + \frac{\text{wt of additive, lb/sk}}{SG \times 8.33} + \text{water vol, gal}$$

c) Water requirement using material balance equation:

$D_1V_1 = D_2V_2$

Example: Class H cement plus 6% bentonite to be mixed at 14.0 lb/gal. Specific gravity of bentonite = 2.65.

Determine the following:

Bentonite requirement, lb/sk
Water requirement, gal/sk
Slurry yield, ft^3/sk
Check slurry weight, lb/gal

1) Weight of materials, lb/sk:

Weight, lb/sk = 94 + (0.06 × 94) + (8.33 × "y")
Weight, lb/sk = 94 + 5.64 + 8.33"y"
Weight = 99.64 + 8.33"y"

2) Volume of slurry, gal/sk:

$$\text{Vol, gal/sk} = \frac{94}{3.14 \times 8.33} + \frac{5.64}{2.65 \times 8.33} + \text{“y”}$$

$$\text{Vol, gal/sk} = 3.6 + 0.26 + \text{“y”}$$

$$\text{Vol, gal/sk} = 3.86 + \text{“y”}$$

3) Water requirement using material balance equation:

$$\begin{aligned}
99.64 + 8.33\text{“y”} &= (3.86 + \text{“y”}) \times 14.0 \\
99.64 + 8.33\text{“y”} &= 54.04 + 14.0\text{“y”} \\
99.64 - 54.04 &= 14.0\text{“y”} - 8.33\text{“y”} \\
45.6 &= 5.67\text{“y”} \\
45.6 \div 5.67 &= \text{“y”} \\
8.0 &= \text{“y” Thus, water requirement} = 8.0\,\text{gal/sk of cement}
\end{aligned}$$

4) Slurry yield, ft³/sk:

$$\text{Yield, ft}^3\text{/sk} = \frac{3.6 + 0.26 + 8.0}{7.48}$$

$$\text{Yield, ft}^3\text{/sk} = \frac{11.86}{7.48}$$

$$\text{Yield} = 1.59\,\text{ft}^3\text{/sk}$$

5) Check slurry density, lb/gal:

$$\text{Density, lb/gal} = \frac{94 + 5.64 + (8.33 \times 8.0)}{11.86}$$

$$\text{Density, lb/gal} = \frac{166.28}{11.86}$$

$$\text{Density} = 14.0\,\text{lb/gal}$$

Field cement additive calculations

When bentonite is to be pre-hydrated, the amount of bentonite added is calculated based on the total amount of mixing water used.

Cement program: 240 sk cement; slurry density = 13.8 ppg; 8.6 gal/sk mixing water; 1.5% bentonite to be pre-hydrated:

a) Volume of mixing water, gal:

Volume = 240 sk × 8.6 gal/sk
Volume = 2064 gal

b) Total weight, lb, of mixing water:

Weight = 2064 gal × 8.33 lb/gal
Weight = 17,193 lb

c) Bentonite requirement, lb:

Bentonite = 17,193 lb × 0.015%
Bentonite = 257.89 lb

Other additives are calculated based on the weight of the cement:

Cement program: 240 sk cement; 0.5% Halad; 0.40% CFR-2:

a) Weight of cement:

Weight = 240 sk × 94 lb/sk
Weight = 22,560 lb

b) Halad = 0.5%

Halad = 22,560 lb × 0.005
Halad = 112.8 lb

c) CFR-2 = 0.40%

CFR-2 = 22,560 lb × 0.004
CFR-2 = 90.24 lb

Table 2-1
Water Requirements and Specific Gravity of Common Cement Additives

Material	Water Requirement gal/94 lb/sk	Specific Gravity
API Class Cement		
Class A & B	5.2	3.14
Class C	6.3	3.14
Class D & E	4.3	3.14
Class G	5.0	3.14
Class H	4.3–5.2	3.14
Chem Comp Cement	6.3	3.14

Table 2-1 (continued)

Material	Water Requirement gal/94 lb/sk	Specific Gravity
Attapulgite	1.3/2% in cement	2.89
Cement Fondu	4.5	3.23
Lumnite Cement	4.5	3.20
Trinity Lite-weight Cement	9.7	2.80
Bentonite	1.3/2% in cement	2.65
Calcium Carbonate Powder	0	1.96
Calcium Chloride	0	1.96
Cal-Seal (Gypsum Cement)	4.5	2.70
CFR-1	0	1.63
CFR-2	0	1.30
D-Air-1	0	1.35
D-Air-2	0	1.005
Diacel A	0	2.62
Diacel D	3.3–7.4/10% in cement	2.10
Diacel LWL	0 (up to 0.7%) 0.8 : 1/1% in cement	1.36
Gilsonite	2/50-lb/ft^3	1.07
Halad-9	0 (up to 5%) 0.4–0.5 over 5%	1.22
Halad 14	0	1.31
HR-4	0	1.56
HR-5	0	1.41
HR-7	0	1.30
HR-12	0	1.22
HR-15	0	1.57
Hydrated Lime	14.4	2.20
Hydromite	2.82	2.15
Iron Carbonate	0	3.70
LA-2 Latex	0.8	1.10
NF-D	0	1.30
Perlite regular	4/8 lb/ft^3	2.20
Perlite 6	6/38 lb/ft^3	–
Pozmix A	4.6–5.0	2.46
Salt (NaCl)	0	2.17
Sand Ottawa	0	2.63
Silica flour	1.6/35% in cement	2.63
Coarse silica	0	2.63
Spacer sperse	0	1.32
Spacer mix (liquid)	0	0.932
Tuf Additive No. 1	0	1.23
Tuf Additive No. 2	0	0.88
Tuf Plug	0	1.28

Weighted Cement Calculations

Amount of high density additive required per sack of cement to achieve a required cement slurry density

$$x = \frac{\left(\frac{wt \times 11.207983}{SGc}\right) + (wt \times CW) - 94 - (8.33 \times CW)}{\left(1 + \frac{AW}{100}\right) - \left(\frac{wt}{SGa \times 8.33}\right) - \left(wt + \frac{AW}{100}\right)}$$

where x = additive required, pounds per sack of cement
Wt = required slurry density, lb/gal
SGc = specific gravity of cement
CW = water requirement of cement
AW = water requirement of additive
SGa = specific gravity of additive

Additive	Water Requirement gal/94 lb/sk	Specific Gravity
Hematite	0.34	5.02
Ilmenite	0	4.67
Barite	2.5	4.23
Sand	0	2.63
API Cements		
Class A & B	5.2	3.14
Class C	6.3	3.14
Class D, E, F, H	4.3	3.14
Class G	5.0	3.14

Example: Determine how much hematite, lb/sk of cement would be required to increase the density of Class H cement to 17.5 lb/gal:

Water requirement of cement = 4.3 gal/sk
Water requirement of additive (hematite) = 0.34 gal/sk
Specific gravity of cement = 3.14
Specific gravity of additive (hematite) = 5.02

Solution:

$$x = \frac{\left(\frac{17.5 \times 11.207983}{3.14}\right) + (17.5 \times 4.3) - 94 - (8.33 \times 4.3)}{\left(1 + \frac{0.34}{100}\right) - \left(\frac{17.5}{5.02 \times 8.33}\right) - \left(17.5 \times \frac{0.34}{100}\right)}$$

$$x = \frac{62.4649 + 75.25 - 94 - 35.819}{1.0034 - 0.418494 - 0.0595}$$

$$x = \frac{7.8959}{0.525406}$$

x = 15.1 lb of hematite per sk of cement used

Calculations for the Number of Sacks of Cement Required

If the number of feet to be cemented is known, use the following:

Step 1

Determine the following capacities:

a) Annular capacity, ft^3/ft:

$$\text{Annular capacity, ft}^3\text{/ft} = \frac{\text{Dh, in.}^2 - \text{Dp, in.}^2}{183.35}$$

b) Casing capacity, ft^3/ft:

$$\text{Casing capacity, ft}^3\text{/ft} = \frac{\text{ID, in.}^2}{183.35}$$

c) Casing capacity, bbl/ft:

$$\text{Casing capacity, bbl/ft} = \frac{\text{ID, in.}^2}{1029.4}$$

Step 2

Determine the number of sacks of LEAD or FILLER cement required:

$$\begin{array}{c} \text{Sacks} \\ \text{required} \end{array} = \begin{array}{c} \text{feet} \\ \text{to be} \\ \text{cemented} \end{array} \times \begin{array}{c} \text{annular} \\ \text{capacity,} \\ \text{ft}^3\text{/ft} \end{array} \times \text{excess} \div \begin{array}{c} \text{yield, ft}^3\text{/sk} \\ \text{LEAD cement} \end{array}$$

Step 3

Determine the number of sacks of TAIL or NEAT cement required:

$$\text{Sacks required annulus} = \text{feet to be cemented} \times \text{annular capacity, ft}^3\text{/ft} \times \text{excess} \div \text{yield, ft}^3\text{/sk TAIL cement}$$

$$\text{Sacks required casing} = \text{no. of feet between float collar \& shoe} \times \text{casing capacity, ft}^3\text{/ft} \div \text{yield, ft}^3\text{/sk TAIL cement}$$

Total Sacks of TAIL cement required:

Sacks = sacks required in annulus + sacks required in casing

Step 4

Determine the casing capacity down to the float collar:

$$\text{Casing capacity, bbl} = \text{casing capacity, bbl/ft} \times \text{feet of casing to the float collar}$$

Step 5

Determine the number of strokes required to bump the plug:

Strokes = casing capacity, bbl ÷ pump output, bbl/stk

Example: From the data listed below determine the following:

1. How many sacks of LEAD cement will be required?
2. How many sacks of TAIL cement will be required?
3. How many barrels of mud will be required to bump the plug?
4. How many strokes will be required to bump the top plug?

Data:	Casing setting depth	= 3000 ft
	Hole size	= 17-1/2 in.
	Casing—54.5 lb/ft	= 13-3/8 in.
	Casing ID	= 12.615 in.
	Float collar (number of feet above shoe)	= 44 ft
	Pump (5-1/2 in. by 14 in. duplex @ 90% eff)	= 0.112 bbl/stk

Cement program:	LEAD cement (13.8 lb/gal)	= 2000 ft
	slurry yield	= 1.59 ft^3/sk
	TAIL cement (15.8 lb/gal)	= 1000 ft
	slurry yield	= 1.15 ft^3/sk
	Excess volume	= 50%

Step 1

Determine the following capacities:

a) Annular capacity, ft^3/ft:

$$\text{Annular capacity, ft}^3\text{/ft} = \frac{17.5^2 - 13.375^2}{183.35}$$

$$\text{Annular capacity, ft}^3\text{/ft} = \frac{127.35938}{183.35}$$

$$\text{Annular capacity} = 0.6946\,\text{ft}^3\text{/ft}$$

b) Casing capacity, ft^3/ft:

$$\text{Casing capacity, ft}^3\text{/ft} = \frac{12.615^2}{183.35}$$

$$\text{Casing capacity, ft}^3\text{/ft} = \frac{159.13823}{183.35}$$

$$\text{Casing capacity} = 0.8679\,\text{ft}^3\text{/ft}$$

c) Casing capacity, bbl/ft:

$$\text{Casing capacity, bbl/ft} = \frac{12.615^2}{1029.4}$$

$$\text{Casing capacity, bbl/ft} = \frac{159.13823}{1029.4}$$

$$\text{Casing capacity} = 0.1545\,\text{bbl/ft}$$

Step 2

Determine the number of sacks of LEAD or FILLER cement required:

$$\text{Sacks required} = 2000\,\text{ft} \times 0.6946\,\text{ft}^3\text{/ft} \times 1.50 \div 1.59\,\text{ft}^3\text{/sk}$$

$$\text{Sacks required} = 1311$$

Step 3

Determine the number of sacks of TAIL or NEAT cement required:

Sacks required annulus = $1000\,ft \times 0.6946\,ft^3/ft \times 1.50 \div 1.15\,ft^3/sk$

Sacks required annulus = 906

Sacks required casing = $44\,ft \times 0.8679\,ft^3/ft \div 1.15\,ft^3/sk$

Sacks required casing = 33

Total sacks of TAIL cement required:

Sacks = 906 + 33
Sacks = 939

Step 4

Determine the barrels of mud required to bump the top plug:

Casing capacity, bbl = $(3000\,ft - 44\,ft) \times 0.1545\,bbl/ft$
Casing capacity = 456.7 bbl

Step 5

Determine the number of strokes required to bump the top plug:

Strokes = $456.7\,bbl \div 0.112\,bbl/stk$
Strokes = 4078

Calculations for the Number of Feet to Be Cemented

If the number of sacks of cement is known, use the following:

Step 1

Determine the following capacities:

a) Annular capacity, ft^3/ft:

$$\text{Annular capacity, } ft^3/ft = \frac{Dh, in.^2 - Dp, in.^2}{183.35}$$

b) Casing capacity, ft^3/ft:

$$\text{Casing capacity, } ft^3/ft = \frac{ID, in.^2}{183.35}$$

Step 2

Determine the slurry volume, ft^3

$$\text{Slurry vol, ft}^3 = \text{number of sacks of cement to be used} \times \text{slurry yield, ft}^3\text{/sk}$$

Step 3

Determine the amount of cement, ft^3, to be left in casing:

$$\text{Cement in casing, ft}^3 = \left(\text{feet of casing} - \text{setting depth of cementing tool, ft}\right) \times \left(\text{casing capacity, ft}^3\text{/ft}\right)$$

Step 4

Determine the height of cement in the annulus—feet of cement:

$$\text{Feet} = \left(\text{slurry vol, ft}^3 - \text{cement remaining in casing, ft}^3\right) \div \left(\text{annular capacity, ft}^3\text{/ft}\right) \div \text{excess}$$

Step 5

Determine the depth of the top of the cement in the annulus:

$$\text{Depth, ft} = \text{casing setting depth, ft} - \text{ft of cement in annulus}$$

Step 6

Determine the number of barrels of mud required to displace the cement:

$$\text{Barrels} = \text{ft of drill pipe} \times \text{drill pipe capacity, bbl/ft}$$

Step 7

Determine the number of strokes required to displace the cement:

$$\text{Strokes} = \text{bbl required to displace cement} \div \text{pump output, bbl/stk}$$

Example: From the data listed below, determine the following:

1. Height, ft, of the cement in the annulus
2. Amount, ft^3, of the cement in the casing
3. Depth, ft, of the top of the cement in the annulus
4. Number of barrels of mud required to displace the cement
5. Number of strokes required to displace the cement

Data:	Casing setting depth	= 3000 ft
	Hole size	= 17-1/2 in.
	Casing—54.5 lb/ft	= 13-3/8 in.
	Casing ID	= 12.615 in.
	Drill pipe (5.0 in.—19.5 lb/ft)	= 0.01776 bbl/ft
	Pump (7 in. by 12 in. triplex @ 95% eff.)	= 0.136 bbl/stk
	Cementing tool (number of feet above shoe)	= 100 ft

Cementing program:	NEAT cement	= 500 sk
	Slurry yield	= 1.15 ft^3/sk
	Excess volume	= 50%

Step 1

Determine the following capacities:

a) Annular capacity between casing and hole, ft^3/ft:

$$\text{Annular capacity, ft}^3/\text{ft} = \frac{17.5^2 - 13.375^2}{183.35}$$

$$\text{Annular capacity, ft}^3/\text{ft} = \frac{127.35938}{183.35}$$

$$\text{Annular capacity} = 0.6946\ \text{ft}^3/\text{ft}$$

b) Casing capacity, ft^3/ft:

$$\text{Casing capacity, ft}^3/\text{ft} = \frac{12.615^2}{183.35}$$

$$\text{Casing capacity, ft}^3/\text{ft} = \frac{159.13823}{183.35}$$

$$\text{Casing capacity} = 0.8679\ \text{ft}^3/\text{ft}$$

Step 2

Determine the slurry volume, ft^3:

$$\text{Slurry vol, ft}^3 = 500\,\text{sk} \times 1.15\,\text{ft}^3/\text{sk}$$
$$\text{Slurry vol} = 575\,\text{ft}^3$$

Step 3

Determine the amount of cement, ft^3, to be left in the casing:

$$\text{Cement in casing, ft}^3 = (3000\,\text{ft} - 2900\,\text{ft}) \times 0.8679\,\text{ft}^3/\text{ft}$$
$$\text{Cement in casing, ft}^3 = 86.79\,\text{ft}^3$$

Step 4

Determine the height of the cement in the annulus—feet of cement:

$$\text{Feet} = \left(575\,\text{ft}^3 - 86.79\,\text{ft}^3\right) \div 0.6946\,\text{ft}^3/\text{ft} \div 1.50$$
$$\text{Feet} = 468.58$$

Step 5

Determine the depth of the top of the cement in the annulus:

$$\text{Depth} = 3000\,\text{ft} - 468.58\,\text{ft}$$
$$\text{Depth} = 2531.42\,\text{ft}$$

Step 6

Determine the number of barrels of mud required to displace the cement:

$$\text{Barrels} = 2900\,\text{ft} \times 0.01776\,\text{bbl/ft}$$
$$\text{Barrels} = 51.5$$

Step 7

Determine the number of strokes required to displace the cement:

$$\text{Strokes} = 51.5\,\text{bbl} \div 0.136\,\text{bbl/stk}$$
$$\text{Strokes} = 379$$

Setting a Balanced Cement Plug

Step 1

Determine the following capacities:

a) Annular capacity, ft³/ft, between pipe or tubing and hole or casing:

$$\text{Annular capacity, ft}^3\text{/ft} = \frac{\text{Dh, in.}^2 - \text{Dp, in.}^2}{183.35}$$

b) Annular capacity, ft/bbl, between pipe or tubing and hole or casing:

$$\text{Annular capacity, ft/bbl} = \frac{1029.4}{\text{Dh, in.}^2 - \text{Dp, in.}^2}$$

c) Hole or casing capacity, ft³/ft:

$$\text{Hole or capacity, ft}^3\text{/ft} = \frac{\text{ID, in.}^2}{183.35}$$

d) Drill pipe or tubing capacity, ft³/ft:

$$\text{Drill pipe or tubing capacity, ft}^3\text{/ft} = \frac{\text{ID, in.}^2}{183.35}$$

e) Drill pipe or tubing capacity, bbl/ft:

$$\text{Drill pipe or tubing capacity, bbl/ft} = \frac{\text{ID, in.}^2}{1029.4}$$

Step 2

Determine the number of SACKS of cement required for a given length of plug, OR determine the FEET of plug for a given number of sacks of cement:

a) Determine the number of SACKS of cement required for a given length of plug:

$$\begin{matrix}\text{Sacks} \\ \text{of} \\ \text{cement}\end{matrix} = \begin{matrix}\text{plug} \\ \text{length,} \\ \text{ft}\end{matrix} \times \begin{matrix}\text{hole or} \\ \text{casing} \\ \text{capacity,} \\ \text{ft}^3\text{/ft}\end{matrix} \times \text{excess} \div \begin{matrix}\text{slurry} \\ \text{yield,} \\ \text{ft}^3\text{/sk}\end{matrix}$$

NOTE: If no excess is to be used, omit the excess step.

OR

b) Determine the number of FEET of plug for a given number of sacks of cement:

$$\text{Feet} = \text{sacks of cement} \times \text{slurry yield, ft}^3\text{/sk} \div \text{hole or casing capacity, ft}^3\text{/ft} \div \text{excess}$$

NOTE: If no excess is to be used, omit the excess step.

Step 3

Determine the spacer volume (usually water), bbl, to be pumped behind the slurry to balance the plug:

$$\text{Spacer vol, bbl} = \text{annular capacity, ft/bbl} \div \text{excess} \times \text{spacer vol ahead, bbl} \times \text{pipe or tubing capacity, bbl/ft}$$

NOTE: if no excess is to be used, omit the excess step.

Step 4

Determine the plug length, ft, before the pipe is withdrawn:

$$\text{Plug length, ft} = \text{sacks of cement} \times \text{slurry yield, ft}^3\text{/sk} \div \text{annular capacity, ft}^3\text{/ft} \times \text{excess} + \text{pipe or tubing capacity, ft}^3\text{/ft}$$

NOTE: If no excess is to be used, omit the excess step.

Step 5

Determine the fluid volume, bbl, required to spot the plug:

$$\text{Vol, bbl} = \text{length of pipe or tubing, ft} - \text{plug length, ft} \times \text{pipe or tubing capacity, bbl/ft} - \text{spacer vol behind slurry bbl}$$

Example 1: A 300 ft plug is to be placed at a depth of 5000 ft. The open hole size is 8-1/2 in. and the drill pipe is 3-1/2 in.—13.3 lb/ft; ID—2.764 in. Ten barrels of water are to be pumped ahead of the slurry. Use a slurry yield of 1.15 ft^3/sk. Use 25% as excess slurry volume:

Determine the following:

1. Number of sacks of cement required
2. Volume of water to be pumped behind the slurry to balance the plug
3. Plug length before the pipe is withdrawn
4. Amount of mud required to spot the plug plus the spacer behind the plug

Step 1

Determined the following capacities:

a) Annular capacity between drill pipe and hole, ft^3/ft:

$$\text{Annular capacity, ft}^3/\text{ft} = \frac{8.5^2 - 3.5^2}{183.35}$$

$$\text{Annular capacity} = 0.3272\,\text{ft}^3/\text{ft}$$

b) Annular capacity between drill pipe and hole, ft/bbl:

$$\text{Annular capacity, ft/bbl} = \frac{1029.4}{8.5^2 - 3.5^2}$$

$$\text{Annular capacity} = 17.1569\,\text{ft/bbl}$$

c) Hole capacity, ft^3/ft:

$$\text{Hole capacity, ft}^3/\text{ft} = \frac{8.5^2}{183.35}$$

$$\text{Hole capacity} = 0.3941\,\text{ft}^3/\text{ft}$$

d) Drill pipe capacity, bbl/ft:

$$\text{Drill pipe capacity, bbl/ft} = \frac{2.764^2}{1029.4}$$

$$\text{Drill pipe capacity} = 0.00742\,\text{bbl/ft}$$

e) Drill pipe capacity, ft^3/ft:

$$\text{Drill pipe capacity, ft}^3/\text{ft} = \frac{2.764^2}{183.35}$$

$$\text{Drill pipe capacity} = 0.0417\,\text{ft}^3/\text{ft}$$

Step 2

Determine the number of sacks of cement required:

$$\text{Sacks of cement} = 300\,\text{ft} \times 0.3941\,\text{ft}^3/\text{ft} \times 1.25 \div 1.15\,\text{ft}^3/\text{sk}$$
$$\text{Sacks of cement} = 129$$

Step 3

Determine the spacer volume (water), bbl, to be pumped behind the slurry to balance the plug:

$$\text{Spacer vol, bbl} = 17.1569\,\text{ft/bbl} \div 1.25 \times 10\,\text{bbl} \times 0.00742\,\text{bbl/ft}$$
$$\text{Spacer vol} = 1.018\,\text{bbl}$$

Step 4

Determine the plug length, ft, before the pipe is withdrawn:

$$\text{Plug length, ft} = \left(\frac{129}{\text{sk}} \times \frac{1.15}{\text{ft}^3/\text{sk}}\right) \div \left(\frac{0.3272}{\text{ft}^3/\text{ft}} \times 1.25 + \frac{0.0417}{\text{ft}^3/\text{ft}}\right)$$

$$\text{Plug length, ft} = 148.35\,\text{ft}^3 \div 0.4507\,\text{ft}^3/\text{ft}$$

$$\text{Plug length} = 329\,\text{ft}$$

Step 5

Determine the fluid volume, bbl, required to spot the plug:

$$\text{Vol, bbl} = [(5000\,\text{ft} - 329\,\text{ft}) \times 0.00742\,\text{bbl/ft}] - 1.0\,\text{bbl}$$

$$\text{Vol, bbl} = 34.66\,\text{bbl} - 1.0\,\text{bbl}$$

$$\text{Volume} = 33.6\,\text{bbl}$$

Example 2: Determine the number of FEET of plug for a given number of SACKS of cement:

A cement plug with 100 sk of cement is to be used in an 8-1/2 in. hole. Use 1.15 ft^3/sk for the cement slurry yield. The capacity of 8-1/2 in. hole = 0.3941 ft^3/ft. Use 50% as excess slurry volume:

Feet = 100 sk × 1.15 ft^3/sk ÷ 0.3941 ft^3/ft ÷ 1.50
Feet = 194.5

Differential Hydrostatic Pressure Between Cement in the Annulus and Mud Inside the Casing

1. Determine the hydrostatic pressure exerted by the cement and any mud remaining in the annulus.
2. Determine the hydrostatic pressure exerted by the mud and cement remaining in the casing.
3. Determine the differential pressure.

Example: 9-5/8 in. casing — 43.5 lb/ft in 12-1/4 in. hole:

Well depth		= 8000 ft
Cementing program:		
LEAD slurry	2000 ft	= 13.8 lb/gal
TAIL slurry	1000 ft	= 15.8 lb/gal
Mud weight		= 10.0 lb/gal
Float collar (No. of feet above shoe)		= 44 ft

Determine the total hydrostatic pressure of cement and mud in the annulus

a) Hydrostatic pressure of mud in annulus:

HP, psi = 10.0 lb/gal × 0.052 × 5000 ft
HP = 2600 psi

b) Hydrostatic pressure of LEAD cement:

HP, psi = 13.8 lb/gal × 0.052 × 2000 ft
HP = 1435 psi

c) Hydrostatic pressure of TAIL cement:

$$\text{HP, psi} = 15.8\,\text{lb/gal} \times 0.052 \times 1000\,\text{ft}$$
$$\text{HP} = 822\,\text{psi}$$

d) Total hydrostatic pressure in annulus:

$$\text{psi} = 2600\,\text{psi} + 1435\,\text{psi} + 822\,\text{psi}$$
$$\text{psi} = 4857$$

Determine the total pressure inside the casing

a) Pressure exerted by the mud:

$$\text{HP, psi} = 10.0\,\text{lb/gal} \times 0.052 \times (8000\,\text{ft} - 44\,\text{ft})$$
$$\text{HP} = 4137\,\text{psi}$$

b) Pressure exerted by the cement:

$$\text{HP, psi} = 15.8\,\text{lb/gal} \times 0.052 \times 44\,\text{ft}$$
$$\text{HP} = 36\,\text{psi}$$

c) Total pressure inside the casing:

$$\text{psi} = 4137\,\text{psi} + 36\,\text{psi}$$
$$\text{psi} = 4173$$

Differential pressure

$$P_D = 4857\,\text{psi} - 4173\,\text{psi}$$
$$P_D = 684\,\text{psi}$$

Hydraulicing Casing

These calculations will determine if the casing will hydraulic out (move upward) when cementing

Determine the difference in pressure gradient, psi/ft, between the cement and the mud

$$\text{psi/ft} = (\text{cement wt, ppg} - \text{mud wt, ppg}) \times 0.052$$

Determine the differential pressure (DP) between the cement and the mud

$$\text{DP, psi} = \frac{\text{difference in}}{\text{pressure gradients, psi/ft}} \times \text{casing length, ft}$$

Determine the area, sq in., below the shoe

Area, sq in. = casing diameter, in.^{2} × 0.7854

Determine the Upward Force (F), lb. This is the weight, total force, acting at the bottom of the shoe

$$\text{Force, lb} = \text{area, sq in.} \times \begin{matrix}\text{differential pressure}\\ \text{between cement and mud, psi}\end{matrix}$$

Determine the Downward Force (W), lb. This is the weight of the casing

Weight, lb = casing wt, lb/ft × length, ft × buoyancy factor

Determine the difference in force, lb

Differential force, lb = upward force, lb − downward force, lb

Pressure required to balance the forces so that the casing will not hydraulic out (move upward)

psi = force, lb ÷ area, sq in.

Mud weight increase to balance pressure

$$\text{Mud wt, ppg} = \begin{matrix}\text{pressure required}\\ \text{to balance forces, psi}\end{matrix} \div 0.052 \div \text{casing length, ft}$$

New mud weight, ppg

Mud wt, ppg = mud wt increase, ppg ÷ mud wt, ppg

Check the forces with the new mud weight

a) psi/ft = (cement wt, ppg − mud wt, ppg) × 0.052
b) psi = difference in pressure gradients, psi/ft × casing length, ft
c) Upward force, lb = pressure, psi × area, sq in.
d) Difference in force, lb = upward force, lb − downward force, lb

Example: Casing size = 13 3/8 in. 54 lb/ft
Cement weight = 15.8 ppg
Mud weight = 8.8 ppg
Buoyancy factor = 0.8656
Well depth = 164 ft (50 m)

Determine the difference in pressure gradient, psi/ft, between the cement and the mud

psi/ft = (15.8 − 8.8) × 0.052
psi/ft = 0.364

Determine the differential pressure between the cement and the mud

psi = 0.364 psi/ft × 164 ft
psi = 60

Determine the area, sq in., below the shoe

area, sq in. = $13.375^2 \times 0.7854$
area, = 140.5 sq in.

Determine the upward force. This is the total force acting at the bottom of the shoe

Force, lb = 140.5 sq in. × 60 psi
Force = 8430 lb

Determine the downward force. This is the weight of casing

Weight, lb = 54.5 lb/ft × 164 ft × 0.8656
Weight = 7737 lb

Determine the difference in force, lb

Differential force, lb = downward force, lb − upward force, lb
Differential force, lb = 7737 lb − 8430 lb
Differential force = −693 lb

Therefore: Unless the casing is tied down or stuck, it could hydraulic out (move upward).

Pressure required to balance the forces so that the casing will not hydraulic out (move upward)

psi = 693 lb ÷ 140.5 sq in.
psi = 4.9

Mud weight increase to balance pressure

Mud wt, ppg = 4.9 psi ÷ 0.052 ÷ 164 ft
Mud wt = 0.57 ppg

New mud weight, ppg

New mud wt, ppg = 8.8 ppg + 0.6 ppg
New mud wt = 9.4 ppg

Check the forces with the new mud weight

a) psi/ft = (15.8 − 9.4) × 0.052
psi/ft = 0.3328

b) psi = 0.3328 psi/ft × 164 ft
psi = 54.58

c) Upward force, lb = 54.58 psi × 140.5 sq in.
Upward force = 7668 lb

d) Differential force, lb = downward force − upward force
7737 lb − 7668 lb

Differential force = +69 lb

Depth of a Washout

Method 1

Pump soft line or other plugging material down the drill pipe and note how many strokes are required before the pump pressure increases.

$$\text{Depth of washout, ft} = \text{strokes required} \times \text{pump output, bbl/stk} \div \text{drill pipe capacity, bbl/ft}$$

Example: Drill pipe = 3-1/2 in.—13.3 lb/ft
capacity = 0.00742 bbl/ft
Pump output = 0.112 bbl/stk (5-1/2 in. by 14 in. duplex @ 90% efficiency)

NOTE: A pressure increase was noted after 360 strokes.

$$\text{Depth of washout, ft} = 360\,\text{stk} \times 0.112\,\text{bbl/stk} \div 0.00742\,\text{bbl/ft}$$

$$\text{Depth of washout} = 5434\,\text{ft}$$

Method 2

Pump some material that will go through the washout, up the annulus and over the shale shaker. This material must be of the type that can be easily observed as it comes across the shaker. Examples: carbide, corn starch, glass beads, brightly colored paint, etc.

$$\text{Depth of washout, ft} = \text{strokes required} \times \text{pump output, bbl/stk} \div \left(\text{drill pipe capacity, bbl/ft} + \text{annular capacity, bbl/ft} \right)$$

Example: Drill pipe = 3-1/2 in. 13.3 lb/ft
capacity = 0.00742 bbl/ft
Pump output = 0.112 bbl/stk (5-1/2 in. × 14 in. duplex @ 90% efficiency)
Annulus
hole size = 8-1/2 in.
capacity = 0.0583 bbl/ft (8-1/2 in. × 3-1/2 in.)

NOTE: The material pumped down the drill pipe came over the shaker after 2680 strokes.

Drill pipe capacity plus annular capacity:

0.00742 bbl/ft + 0.0583 bbl/ft = 0.0657 bbl/ft

$$\text{Depth of washout, ft} = 2680\text{stk} \times 0.112\,\text{bbl/stk} \div 0.0657\,\text{bbl/ft}$$

$$\text{Depth of washout} = 4569\,\text{ft}$$

Lost Returns—Loss of Overbalance

Number of feet of water in annulus

Feet = water added, bbl ÷ annular capacity, bbl/ft

Bottomhole (BHP) pressure reduction

$$\text{BHP decrease, psi} = \left(\text{mud wt, ppg} - \text{wt of water, ppg}\right) \times 0.052 \times \left(\text{ft of water added}\right)$$

Equivalent mud weight at TD

EMW, ppg = mud wt, ppg − (BHP decrease, psi ÷ 0.052 ÷ TVD, ft)

Example:

Mud weight	=	12.5 ppg
Weight of water	=	8.33 ppg
TVD	=	10,000 ft
Annular capacity	=	0.1279 bbl/ft (12-1/4 × 5.0 in.)
Water added	=	150 bbl required to fill annulus

Number of feet of water in annulus

Feet = 150 bbl ÷ 0.1279 bbl/ft
Feet = 1173

Bottomhole pressure decrease

BHP decrease, psi = (12.5 ppg − 8.33 ppg) × 0.052 × 1173 ft
BHP decrease = 254 psi

Equivalent mud weight at TD

EMW, ppg = 12.5 − (254 psi ÷ 0.052 ÷ 10,000 ft)
EMW = 12.0 ppg

Stuck Pipe Calculations

Determine the feet of free pipe and the free point constant

Method 1

The depth at which the pipe is stuck and the number of feet of free pipe can be estimated by the drill pipe stretch table below and the following formula.

Table 2-2
Drill Pipe Stretch Table

ID, in.	Nominal Weight, lb/ft	ID, in.	Wall Area, sq in.	Stretch Constant in/1000 lb /1000 ft	Free Point constant
2-3/8	4.85	1.995	1.304	0.30675	3260.0
	6.65	1.815	1.843	0.21704	4607.7
2-7/8	6.85	2.241	1.812	0.22075	4530.0
	10.40	2.151	2.858	0.13996	7145.0
3-1/2	9.50	2.992	2.590	0.15444	6475.0
	13.30	2.764	3.621	0.11047	9052.5
	15.50	2.602	4.304	0.09294	10760.0
4.0	11.85	3.476	3.077	0.13000	7692.5
	14.00	3.340	3.805	0.10512	9512.5
4-1/2	13.75	3.958	3.600	0.11111	9000.0
	16.60	3.826	4.407	0.09076	11017.5
	18.10	3.754	4.836	0.08271	12090.0
	20.00	3.640	5.498	0.07275	13745.0
5.0	16.25	4.408	4.374	0.09145	10935.0
	19.50	4.276	5.275	0.07583	13187.5
5-1/2	21.90	4.778	5.828	0.06863	14570.0
	24.70	4.670	6.630	0.06033	16575.0
6-5/8	25.20	5.965	6.526	0.06129	16315.0

$$\text{Feet of free pipe} = \frac{\text{stretch, in.} \times \text{free point constant}}{\text{pull force in thousands of pounds}}$$

Example: 3-1/2 in. 13.30 lb/ft drill pipe
20 in. of stretch with 35,000 lb of pull force

From drill pipe stretch table:

Free point constant = 9052.5 for 3-1/2 in. drill pipe 13.30 lb/ft

$$\text{Feet of free pipe} = \frac{20\text{ in.} \times 9052.5}{35}$$

$$\text{Feet of free pipe} = 5173\text{ ft}$$

Determine free point constant (FPC)

The free point constant can be determined for any type of steel drill pipe if the outside diameter, in., and inside diameter, in., are known:

$$\text{FPC} = A_S \times 2500$$

where A_S = pipe wall cross sectional area, sq in.

Example 1: From the drill pipe stretch table:
4-1/2 in. drill pipe 16.6 lb/ft—ID = 3.826 in.

$$\text{FPC} = (4.5^2 - 3.826^2 \times 0.7854) \times 2500$$
$$\text{FPC} = 4.407 \times 2500$$
$$\text{FPC} = 11{,}017.5$$

Example 2: Determine the free point constant and the depth the pipe is stuck using the following data:

2-3/8 in. tubing—6.5 lb/ft—ID = 2.441 in.
25 in. of stretch with 20,000 lb of pull force

a) Determine free point constant (FPC):

$$\text{FPC} = (2.875^2 - 2.441^2 \times 0.7854) \times 2500$$
$$\text{FPC} = 1.820 \times 2500$$
$$\text{FPC} = 4530$$

b) Determine the depth of stuck pipe:

$$\text{Feet of free pipe} = \frac{25\text{ in.} \times 4530}{20}$$

$$\text{Feet of free pipe} = 5663\text{ ft}$$

Method 2

$$\text{Free pipe, ft} = \frac{735{,}294 \times e \times Wdp}{\text{differential pull, lb}}$$

where e = pipe stretch, in.
Wdp = drill pipe weight, lb/ft (plain end)

Plain end weight, lb/ft, is the weight of drill pipe excluding tool joints:

Weight, lb/ft = 2.67 × pipe OD, in.^{2} − pipe; ID, in.^{2}

Example: Determine the feet of free pipe using the following data:
5.0 in. drill pipe; ID—4.276 in.; 19.5 lb/ft
Differential stretch of pipe = 24 in.
Differential pull to obtain stretch = 30,000 lb

$$\text{Weight, lb/ft} = 2.67 \times (5.0^2 - 4.276^2)$$
$$\text{Weight} = 17.93\text{ lb/ft}$$

$$\text{Free pipe, ft} = \frac{735{,}294 \times 24 \times 17.93}{30{,}000}$$

$$\text{Free pipe} = 10{,}547\text{ ft}$$

Determine the height, ft, of unweighted spotting fluid that will balance formation pressure in the annulus:

a) Determine the difference in pressure gradient, psi/ft, between the mud weight and the spotting fluid:

psi/ft = (mud wt, ppg − spotting fluid wt, ppg) × 0.052

b) Determine the height, ft, of unweighted spotting fluid that will balance formation pressure in the annulus:

$$\text{Height, ft} = \frac{\text{amount of}}{\text{overbalance, psi}} \div \frac{\text{difference in}}{\text{pressure gradient, psi/ft}}$$

Example: Use the following data to determine the height, ft, of spotting fluid that will balance formation pressure in the annulus:

Data: Mud weight = 11.2 ppg
Weight of spotting fluid = 7.0 ppg
Amount of overbalance = 225.0 psi

a) Difference in pressure gradient, psi/ft:

psi/ft = (11.2 ppg − 7.0 ppg) × 0.052
psi/ft = 0.2184

b) Determine the height, ft, of unweighted spotting fluid that will balance formation pressure in the annulus:

Height, ft = 225 psi ÷ 0.2184 psi/ft
Height = 1030 ft

Therefore: Less than 1030 ft of spotting fluid should be used to maintain a safety factor that will prevent a kick or blowout.

Calculations Required for Spotting Pills

The following will be determined:

a) Barrels of spotting fluid (pill) required
b) Pump strokes required to spot the pill

Step 1

Determine the annular capacity, bbl/ft, for drill pipe and drill collars in the annulus:

$$\text{Annular capacity, bbl/ft} = \frac{\text{Dh, in.}^2 - \text{Dp, in.}^2}{1029.4}$$

Step 2

Determine the volume of pill required in the annulus:

Vol, bbl = annular cap., bbl/ft × section length, ft × washout factor

Step 3

Determine total volume, bbl, of spotting fluid (pill) required:

Barrels = Barrels required in annulus plus barrels to be left in drill string

Step 4

Determine drill string capacity, bbl:

Barrels = drill pipe/drill collar capacity, bbl/ft $\times$ length, ft

Step 5

Determine strokes required to pump pill:

Strokes = vol of pill, bbl $\div$ pump output, bbl/stk

Step 6

Determine number of barrels required to chase pill:

$$\text{Barrels} = \begin{matrix}\text{drill string} \\ \text{vol, bbl}\end{matrix} - \begin{matrix}\text{vol left in drill} \\ \text{string, bbl}\end{matrix}$$

Step 7

Determine strokes required to chase pill:

$$\text{Strokes} = \begin{matrix}\text{bbl required} \\ \text{to chase pill}\end{matrix} \div \begin{matrix}\text{pump} \\ \text{output,} \\ \text{bbl/stk}\end{matrix} + \begin{matrix}\text{strokes required} \\ \text{to displace} \\ \text{surface system}\end{matrix}$$

Step 8

Total strokes required to spot the pill:

$$\text{Total strokes} = \begin{matrix}\text{strokes required} \\ \text{to pump pill}\end{matrix} + \begin{matrix}\text{strokes required} \\ \text{to chase pill}\end{matrix}$$

Example: Drill collars are differentially stuck. Use the following data to spot an oil-based pill around the drill collars plus 200 ft (optional) above the collars. Leave 24 bbl in the drill string:

Data: well depth = 10,000 ft
Hole diameter = 8-1/2 in.
Washout factor = 20%
Drill pipe = 5.0 in.—19.5 lb/ft
capacity = 0.01776 bbl/ft
length = 9400 ft
Drill collars = 6-1/2 in. OD × 2-1/2 in. ID
capacity = 0.0061 bbl/ft
length = 600 ft
Pump output = 0.117 bbl/stk

Strokes required to displace surface system from suction tank to the drill pipe = 80 stk.

Step 1

Annular capacity around drill pipe and drill collars:

a) Annular capacity around drill collars:

$$\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 6.5^2}{1029.4}$$

$$\text{Annular capacity} = 0.02914 \text{ bbl/ft}$$

b) Annular capacity around drill pipe:

$$\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 5.0^2}{1029.4}$$

$$\text{Annular capacity} = 0.0459 \text{ bbl/ft}$$

Step 2

Determine total volume of pill required in annulus:

a) Volume opposite drill collars:

Vol, bbl = 0.02914 bbl/ft × 600 ft × 1.20
Vol = 21.0 bbl

b) Volume opposite drill pipe:

Vol, bbl = 0.0459 bbl/ft × 200 ft × 1.20
Vol = 11.0 bbl

c) Total volume, bbl, required in annulus:

Vol, bbl = 21.0 bbl + 11.0 bbl
Vol = 32.0 bbl

Step 3

Total bbl of spotting fluid (pill) required:

Barrels = 32.0 bbl (annulus) + 24.0 bbl (drill pipe)
Barrels = 56.0 bbl

Step 4

Determine drill string capacity:

a) Drill collar capacity, bbl:

Capacity, bbl = 0.0062 bbl/ft × 600 ft
Capacity = 3.72 bbl

b) Drill pipe capacity, bbl:

Capacity, bbl = 0.01776 bbl/ft × 9400 ft
Capacity = 166.94 bbl

c) Total drill string capacity, bbl:

Capacity, bbl = 3.72 bbl + 166.94 bbl
Capacity = 170.6 bbl

Step 5

Determine strokes required to pump pill:

Strokes = 56 bbl ÷ 0.117 bbl/stk
Strokes = 479

Step 6

Determine bbl required to chase pill:

Barrels = 170.6 bbl − 24 bbl
Barrels = 146.6

Step 7

Determine strokes required to chase pill:

Strokes = 146.6 bbl ÷ 0.117 bbl/stk + 80 stk
Strokes = 1333

Step 8

Determine strokes required to spot the pill:

Total strokes = 479 + 1333
Total strokes = 1812

Pressure Required to Break Circulation

Pressure required to overcome the mud's gel strength inside the drill string

Pgs = (y ÷ 300 ÷ d) L

where Pgs = pressure required to break gel strength, psi
y = 10 min gel strength of drilling fluid, lb/100 sq ft
d = inside diameter of drill pipe, in.
L = length of drill string, ft

Example:

y = 10 lb/100 sq ft
d = 4.276 in.
L = 12,000 ft

Pgs = (10 ÷ 300 ÷ 4.276) 12,000 ft
Pgs = 0.007795 × 12,000 ft
Pgs = 93.5 psi

Therefore, approximately 94 psi would be required to break circulation.

Pressure required to overcome the mud's gel strength in the annulus

Pgs = y ÷ [300 (Dh, in. − Dp, in.)] × L

where Pgs = pressure required to break gel strength, psi
L = length of drill string, ft
y = 10 min. gel strength of drilling fluid, lb/100 sq ft
Dh = hole diameter, in.
Dp = pipe diameter, in.

Example: L = 12,000 ft
y = 10 lb/100 sq ft
Dh = 12-1/4 in.
Dp = 5.0 in.

$$Pgs = 10 \div [300 \times (12.25 - 5.0)] \times 12{,}000\,\text{ft}$$
$$Pgs = 10 \div 2175 \times 12{,}000\,\text{ft}$$
$$Pgs = 55.2\,\text{psi}$$

Therefore, approximately 55 psi would be required to break circulation.

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CHAPTER THREE

DRILLING FLUIDS

Increase Mud Density

Mud weight, ppg, increase with barite (average specific gravity of barite—4.2)

$$\text{Barite, sk/100 bbl} = \frac{1470(W_2 - W_1)}{35 - W_2}$$

Example: Determine the number of sacks of barite required to increase the density of 100 bbl of 12.0 ppg (W_1) mud to 14.0 ppg (W_2):

$$\text{Barite, sk/100 bbl} = \frac{1470(14.0 - 12.0)}{35 - 14.0}$$

$$\text{Barite, sk/100 bbl} = \frac{2940}{21.0}$$

$$\text{Barite} = 140\ \text{sk/100 bbl}$$

Metric calculation

$$\text{Barite, kg/m}^3 = \frac{(\text{kill fluid density, kg/l} - \text{original fluid density, kg/l}) \times 4.2}{4.2 - \text{kill fluid density, kg/l}}$$

$$\text{Barite, kg/m}^3 = \frac{(\text{kill fluid density, kg/l} - \text{original fluid density, kg/l}) \times 4200}{4.2 - \text{kill fluid density, kg/l}}$$

S.I. units calculation

$$\text{Barite, kg/m}^3 = \frac{\begin{pmatrix}\text{kill fluid density, kg/m}^3 - \\ \text{original fluid density kg/m}^3\end{pmatrix} \times 4200}{4200 - \text{kill fluid density, kg/m}^3}$$

Volume increase, bbl, due to mud weight increase with barite

$$\text{Volume increase, per 100 bbl} = \frac{100(W_2 - W_1)}{35 - W_2}$$

Example: Determine the volume increase when increasing the density from 12.0 ppg (W_1) to 14.0 ppg (W_2):

$$\text{Volume increase, per 100 bbl} = \frac{100(14.0 - 12.0)}{35 - 14.0}$$

$$\text{Volume increase, per 100 bbl} = \frac{200}{21}$$

$$\text{Volume increase} = 9.52\text{ bbl per 100 bbl}$$

Starting volume, bbl, of original mud weight required to yield a predetermined final volume of desired mud weight with barite

$$\text{Starting volume, bbl} = \frac{V_F(35 - W_2)}{35 - W_1}$$

Example: Determine the starting volume, bbl, of 12.0 ppg (W_1) mud required to achieve 100 bbl (V_F) of 14.0 ppg (W_2) mud with barite:

$$\text{Starting volume, bbl} = \frac{100(35 - 14.0)}{35 - 12.0}$$

$$\text{Starting volume, bbl} = \frac{2100}{23}$$

$$\text{Starting volume} = 91.3\text{ bbl}$$

Mud weight increase with calcium carbonate (SG—2.7)

NOTE: The maximum practical mud weight attainable with calcium carbonate is 14.0 ppg.

$$\text{Sacks/100 bbl} = \frac{945(W_2 - W_1)}{22.5 - W_2}$$

Example: Determine the number of sacks of calcium carbonate/100 bbl required to increase the density from 12.0 ppg (W_1) to 13.0 ppg (W_2):

$$\text{Sacks/100 bbl} = \frac{945(13.0 - 12.0)}{22.5 - 13.0}$$

$$\text{Sacks/100 bbl} = \frac{945}{9.5}$$

$$\text{Sacks/100 bbl} = 99.5$$

Volume increase, bbl, due to mud weight increase with calcium carbonate

$$\text{Volume increase, per 100 bbl} = \frac{100(W_2 - W_1)}{22.5 - W_2}$$

Example: Determine the volume increase, bbl/100 bbl, when increasing the density from 12.0 ppg (W_1) to 13.0 ppg (W_2):

$$\text{Volume increase, per 100 bbl} = \frac{100(13.0 - 12.0)}{22.5 - 13.0}$$

$$\text{Volume increase, per 100 bbl} = \frac{100}{9.5}$$

$$\text{Volume increase} = 10.53 \text{ bbl per 100 bbl}$$

Starting volume, bbl, of original mud weight required to yield a predetermined final volume of desired mud weight with calcium carbonate

$$\text{Starting volume, bbl} = \frac{V_F(22.5 - W_2)}{22.5 - W_1}$$

Example: Determine the starting volume, bbl, of 12.0 ppg (W_1) mud required to achieve 100 bbl (V_F) of 13.0 ppg (W_2) mud with calcium carbonate:

$$\text{Starting volume, bbl} = \frac{100(22.5 - 13.0)}{22.5 - 12.0}$$

$$\text{Starting volume, bbl} = \frac{950}{10.5}$$

$$\text{Starting volume} = 90.5 \text{ bbl}$$

Mud weight increase with hematite (SG—4.8)

$$\text{Hematite, sk/100 bbl} = \frac{1680(W_2 - W_1)}{40 - W_2}$$

Example: Determine the hematite, sk/100 bbl, required to increase the density of 100 bbl of 12.0 ppg (W_1) to 14.0 ppg (W_2):

$$\text{Hematite, sk/100 bbl} = \frac{1680(14.0 - 12.0)}{40 - 14.0}$$

$$\text{Hematite, sk/100 bbl} = \frac{3360}{26}$$

$$\text{Hematite} = 129.2\,\text{sk/100 bbl}$$

Volume increase, bbl, due to mud weight increase with hematite

$$\text{Volume increase, per 100 bbl} = \frac{100(W_2 - W_1)}{40 - W_2}$$

Example: Determine the volume increase, bbl/100 bbl, when increasing the density from 12.0 ppg (W_1) to 14.0 ppg (W_2):

$$\text{Volume increase, per 100 bbl} = \frac{100(14.0 - 12.0)}{40 - 14.0}$$

$$\text{Volume increase, per 100 bbl} = \frac{200}{26}$$

$$\text{Volume increase} = 7.7\,\text{bbl per 100 bbl}$$

Starting volume, bbl, of original mud weight required to yield a predetermined final volume of desired mud weight with hematite

$$\text{Starting volume, bbl} = \frac{V_F(40 - W_2)}{40 - W_1}$$

Example: Determine the starting volume, bbl, of 12.0 ppg (W_1) mud required to achieve 100 bbl (V_F) of 14.0 ppg (W_2) mud with hematite:

$$\text{Starting volume, bbl} = \frac{100(40 - 14.0)}{40 - 12.0}$$

$$\text{Starting volume, bbl} = \frac{2600}{28}$$

$$\text{Starting volume} = 92.9\,\text{bbl}$$

Dilution

Mud weight reduction with water

$$\text{Water, bbl} = \frac{V_1(W_1 - W_2)}{W_2 - D_W}$$

Example: Determine the number of barrels of water weighing 8.33 ppg (D_W) required to reduce 100 bbl (V_1) of 14.0 ppg (W_1) to 12.0 ppg (W_2):

$$\text{Water, bbl} = \frac{100(14.0 - 12.0)}{12.0 - 8.33}$$

$$\text{Water, bbl} = \frac{2000}{3.67}$$

$$\text{Water} = 54.5\,\text{bbl}$$

Mud weight reduction with diesel oil

$$\text{Diesel, bbl} = \frac{V_1(W_1 - W_2)}{W_2 - D_W}$$

Example: Determine the number of barrels of diesel weighing 7.0 ppg (D_W) required to reduce 100 bbl (V_1) of 14.0 ppg (W_1) mud to 12.0 ppg (W_2):

$$\text{Diesel, bbl} = \frac{100(14.0 - 12.0)}{12.0 - 7.0}$$

$$\text{Diesel, bbl} = \frac{200}{5.0}$$

$$\text{Diesel} = 40\,\text{bbl}$$

Mixing Fluids of Different Densities

Formula: $(V_1D_1) + (V_2D_2) = V_FD_F$

where V_1 = volume of fluid 1 (bbl, gal, etc.)
D_1 = density of fluid 1 (ppg, lb/ft^3, etc.)
V_2 = volume of fluid 2 (bbl, gal, etc.)
D_2 = density of fluid 2 (ppg, lb/ft^3, etc.)
V_F = volume of final fluid mix
D_F = density of final fluid mix

Example 1: A limit is placed on the desired volume:

Determine the volume of 11.0 ppg mud and 14.0 ppg mud required to build 300 bbl of 11.5 ppg mud:

Given: 400 bbl of 11.0 ppg mud on hand, and
400 bbl of 14.0 ppg mud on hand

Solution: let V_1 = bbl of 11.0 ppg mud
V_2 = bbl of 14.0 ppg mud

then a) $V_1 + V_2 = 300$ bbl
b) $(11.0)\ V_1 + (14.0)\ V_2 = (11.5)\ (300)$

Multiply Equation A by the density of the lowest mud weight (D_1 = 11.0 ppg) and subtract the result from Equation B:

$$
\begin{array}{rl}
\text{b)} & (11.0)(V_1) + (14.0)(V_2) = 3450 \\
-\ \text{a)} & \underline{(11.0)(V_1) + (11.0)(V_2) = 3300} \\
 & 0 \qquad\quad (3.0)(V_2) = 150 \\
 & 3\,V_2 = 150 \\
 & V_2 = \dfrac{150}{3} \\
 & V_2 = 50
\end{array}
$$

Therefore: V_2 = 50 bbl of 14.0 ppg mud
$V_1 + V_2$ = 300 bbl
V_1 = 300 − 50
V_1 = 250 bbl of 11.0 ppg mud

Check: V_1 = 50 bbl
D_1 = 14.0 ppg
V_2 = 150 bbl

D_2 = 11.0 ppg
V_F = 300 bbl
D_F = final density, ppg

$$(50)(14.0) + (250)(11.0) = 300D_F$$
$$700 + 2750 = 300D_F$$
$$3450 = 300D_F$$
$$3450 \div 300 = D_F$$
$$11.5\,\text{ppg} = D_F$$

Example 2: No limit is placed on volume:

Determine the density and volume when the following two muds are mixed together:

Given: 400 bbl of 11.0 ppg mud, and
400 bbl of 14.0 ppg mud

Solution: let V_1 = bbl of 11.0 ppg mud
D_1 = density of 11.0 ppg mud
V_2 = bbl of 14.0 ppg mud
D_2 = density of 14.0 ppg mud
V_F = final volume, bbl
D_F = final density, ppg

Formula: $(V_1D_1) + (V_2D_2) = V_FD_F$

$$(400)(11.0) + (400)(14.0) = 800D_F$$
$$400 + 5600 = 800\,D_F$$
$$10{,}000 = 800\,D_F$$
$$10{,}000 \div 800 = D_F$$
$$12.5\,\text{ppg} = D_F$$

Therefore: final volume = 800 bbl
final density = 12.5 ppg

Oil-Based Mud Calculations

Density of oil/water mixture being used

$$(V_1)(D_1) + (V_2)(D_2) = (V_1 + V_2)D_F$$

Example: If the oil/water (o/w) ratio is 75/25 (75% oil, V_1, and 25% water, V_2), the following material balance is set up:

NOTE: The weight of diesel oil, D_1 = 7.0 ppg
The weight of water, D_2 = 8.33 ppg

$$(0.75)(7.0) + (0.25)(8.33) = (0.75 + 0.25)\,D_F$$
$$5.25 + 2.0825 = 1.0\,D_F$$
$$7.33 = D_F$$

Therefore: The density of the oil/water mixture = 7.33 ppg

Starting volume of liquid (oil plus water) required to prepare a desired volume of mud

$$SV = \frac{35 - W_2}{35 - W_1} \times DV$$

where SV = starting volume, bbl
W_1 = initial density of oil/water mixture, ppg
W_2 = desired density, ppg
DV = desired volume, bbl

Example: W_1 = 7.33 ppg (o/w ratio – 75/25)
W_2 = 16.0 ppg
D_V = 100 bbl

Solution: $$SV = \frac{35 - 16}{35 - 7.33} \times 100$$

$$SV = \frac{19}{27.67} \times 100$$

$$SV = 0.68666 \times 100$$

$$SV = 68.7\text{ bbl}$$

Oil/water ratio from retort data

Obtain the percent-by-volume oil and percent-by-volume water from retort analysis or mud still analysis. Using the data obtained, the oil/water ratio is calculated as follows:

a) $$\%\text{ oil in liquid phase} = \frac{\%\text{ by vol oil}}{\%\text{ by vol oil} + \%\text{ by vol water}} \times 100$$

b) $\%$ water in liquid phase $= \dfrac{\%\text{ by vol water}}{\%\text{ by vol oil} + \%\text{ by vol water}} \times 100$

c) Result: The oil/water ratio is reported as the percent oil and the percent water.

Example: Retort annalysis: % by volume oil = 51
% by volume water = 17
% by volume solids = 32

Solution: a) % oil in liquid phase $= \dfrac{51}{51 \times 17} \times 100$

% oil in liquid phase = 75

b) % water in liquid phase $= \dfrac{17}{51 + 17} \times 100$

% water in liquid phase = 25

c) Result: Therefore, the oil/water ratio is reported as 75/25: 75% oil and 25% water.

Changing oil/water ratio

NOTE: If the oil/water ratio is to be increased, add oil; if it is to be decreased, add water.

Retort analysis: % by volume oil = 51
% by volume water = 17
% by volume solids = 32

The oil/water ratio is 75/25.

Example 1: Increase the oil/water ratio to 80/20:

In 100 bbl of this mud, there are 68 bbl of liquid (oil plus water). To increase the oil/water ratio, add oil. The total liquid volume will be increased by the volume of the oil added, but the water volume will not change. The 17 bbl of water now in the mud represents 25% of the liquid volume, but it will represent only 20% of the new liquid volume.

Therefore: let x = final liquid volume

then, $0.20x = 17$
$x = 17 \div 0.20$
$x = 85\,\text{bbl}$

The new liquid volume = 85 bbl

Barrels of oil to be added:

Oil, bbl = new liquid vol − original liquid vol
Oil, bbl = 85 − 68
Oil = 17 bbl oil per 100 bbl of mud

Check the calculations. If the calculated amount of liquid is added, what will be the resulting oil/water ratio?

$$\%\text{ oil in liquid phase} = \frac{\text{original vol oil} + \text{new vol oil}}{\text{original liquid oil} + \text{new oil added}} \times 100$$

$$\%\text{ oil in liquid phase} = \frac{51 + 17}{68 + 17} \times 100$$

$$\%\text{ oil in liquid phase} = 80$$

% water would then be: 100 − 80 = 20

Therefore: The new oil/water ratio would be 80/20.

Example 2: Change the oil/water ratio to 70/30:

As in Example 1, there are 68 bbl of liquid in 100 bbl of this mud. In this case, however, water will be added and the volume of oil will remain constant. The 51 bbl of oil represents 75% of the original liquid volume and 70% of the final volume:

Therefore: let x = final liquid volume

then, $0.70x = 51$
$x = 51 \div 0.70$
$x = 73\,\text{bbl}$

The new liquid volume = 73 bbl

Barrels of water to be added:

Water, bbl = new liquid vol − original liquid vol
Water, bbl = 73 − 68
Water = 5 bbl of water per 100 bbl of mud

Check the calculations. If the calculated amount of water is added, what will be the resulting oil/water ratio?

$$\text{\% water in liquid phase} = \frac{17 + 5}{68 + 5} \times 100$$

$$\text{\% water in liquid phase} = 30$$

$$\text{\% water in liquid phase} = 100 - 30 = 70$$

Therefore, the new oil/water ratio would be 70/30.

Solids Analysis

Basic solids analysis calculations

NOTE: Steps 1–4 are performed on high salt content muds. For low chloride muds begin with Step 5.

Step 1

Percent-by-volume saltwater (SW)

$$SW = (5.88 \times 10^{-8}) \times \left[(\text{ppm CI})^{1.2} + 1\right] \times \text{\% by vol water}$$

Step 2

Percent-by-volume suspended solids (SS)

$$SS = 100 - \text{\% by vol oil} - \text{\% by vol SW}$$

Step 3

Average specific gravity of saltwater (ASGsw)

$$ASGsw = (\text{ppm CI})^{0.95} \times (1.94 \times 10^{-6}) + 1$$

Step 4

Average specific gravity of solids (ASG)

$$\text{ASG} = \frac{(12 \times \text{MW}) - (\%\text{ by vol SW} \times \text{ASGsw}) - (0.84 \times \%\text{ by vol oil})}{\text{SS}}$$

Step 5

Average specific gravity of solids (ASG)

$$\text{ASG} = \frac{(12 \times \text{MW}) - \%\text{ by vol water} - \%\text{ by vol oil}}{\%\text{ by vol solids}}$$

Step 6

Percent-by-volume low gravity solids (LGS)

$$\text{LGS} = \frac{\%\text{ by volume solids} \times (4.2 - \text{ASG})}{1.6}$$

Step 7

Percent-by-volume barite

Barite, % by vol = % by vol solids − % by vol LGS

Step 8

Pounds-per-barrel barite

Barite, lb/bbl = % by vol barite × 14.71

Step 9

Bentonite determination

If cation exchange capacity (CEC)/methylene blue test (MBT) of shale and mud are KNOWN:

a) Bentonite, lb/bbl:

$$= \frac{1}{1 - \left(\frac{S}{65}\right)} \times \left(M - 9 \times \frac{S}{65}\right) \times \%\text{ by vol LGS}$$

where S = CEC of shale
M = CEC of mud

b) Bentonite, % by volume:

Bent, % by vol = bentonite, lb/bbl ÷ 9.1

If the cation exchange capacity (CEC)/methylene blue (MBT) of SHALE is UNKNOWN:

a) $\text{Bentonite, \% by volume} = \dfrac{\text{M} - \text{\% by volume LGS}}{8}$

where M = CEC of mud

b) Bentonite, lb/bbl = bentonite, % by vol × 9.1

Step 10

Drilled solids, % by volume

Drilled solids, % by vol = LGS, % by vol − bent, % by vol

Step 11

Drilled solids, lb/bbl

Drilled solids, lb/bbl = drilled solids, % by vol × 9.1

Example: Mud weight = 16.0 ppg
Chlorides = 73,000 ppm
CEC of mud = 30 lb/bbl
CEC of shale = 7 lb/bbl
Rector Analysis:
water = 57.0% by volume
oil = 7.5% by volume
solids = 35.5% by volume

1. Percent by volume saltwater (SW)

$$SW = \left[(5.88 \times 10^{-8})(73{,}000)^{1.2} + 1\right] \times 57$$

$$SW = [(5.88^{-8} \times 685468.39) + 1] \times 57$$
$$SW = (0.0403055 + 1) \times 57$$
$$SW = 59.2974 \text{ percent by volume}$$

2. Percent by volume suspended solids (SS)

SS = 100 − 7.5 − 59.2974
SS = 33.2026 percent by volume

3. Average specific gravity of saltwater (ASGsw)

$$ASGsw = \left[(73{,}000)^{0.95}(1.94 \times 10^{-6})\right] + 1$$
$$ASGsw = \left(41{,}701.984 \times 1.94^{-6}\right) + 1$$
$$ASGsw = 0.0809018 + 1$$
$$ASGsw = 1.0809$$

4. Average specific gravity of solids (ASG)

$$ASG = \frac{(12 \times 16) - (59.2974 \times 1.0809) - (0.84 \times 7.5)}{33.2026}$$

$$ASG = \frac{121.60544}{33.2026}$$

$$ASG = 3.6625$$

5. Because a high chloride example is being used, Step 5 is omitted.

6. Percent by volume low gravity solids (LGS)

$$LGS = \frac{33.2026 \times (4.2 - 3.6625)}{1.6}$$

LGS = 11.154 percent by volume

7. Percent by volume barite

Barite, % by volume = 33.2026 − 11.154
Barite = 22.0486 % by volume

8. Barite, lb/bbl

Barite, lb/bbl = 22.0486 × 14.71
Barite = 324.3349 lb/bbl

9. Bentonite determination

a) $$\text{lb/bbl} = \frac{1}{1 - \left(\frac{7}{65}\right)} \times \left(30 - 9 \times \frac{7}{65}\right) \times 11.154$$

lb/bbl = 1.1206897 × 2.2615385 × 11.154
Bent = 28.26965 lb/bb

b) Bentonite, % by volume

Bent, % by vol = 28.2696 ÷ 9.1
Bent = 3.10655% by vol

10. Drilled solids, percent by volume

Drilled solids, % by vol = 11.154 − 3.10655
Drilled solids = 8.047% by vol

11. Drilled solids, pounds per barrel

Drilled solids, lb/bbl = 8.047 × 9.1
Drilled solids = 73.2277 lb/bbl

Solids Fractions

Maximum recommended solids fractions (SF)

$$SF = (2.917 \times MW) - 14.17$$

Maximum recommended low gravity solids (LGS)

$$LGS = \left\{\frac{SF}{100} - \left[0.3125 \times \left(\frac{MW}{8.33} - 1\right)\right]\right\} \times 200$$

where SF = maximum recommended solids fractions, % by vol
MW = mud weight, ppg
LGS = maximum recommended low gravity solids, % by vol

Example: Mud weight = 14.0 ppg

Determine: Maximum recommended solids, % by volume
Low gravity solids fraction, % by volume

Maximum recommended solids fractions (SF), % by volume:

SF = (2.917 × 14.0) − 14.17
SF = 40.838 − 14.17
SF = 26.67% by volume

Low gravity solids (LGS), % by volume:

$$\text{LGS} = \left\{\frac{26.67}{100} - \left[0.3125 \times \left(\frac{14.0}{8.33} - 1\right)\right]\right\} \times 200$$

$$\text{LGS} = 0.2667 - (0.3125 \times 0.6807) \times 200$$
$$\text{LGS} = (0.2667 - 0.2127) \times 200$$
$$\text{LGS} = 0.054 \times 200$$
$$\text{LGS} = 10.8\% \text{ by volume}$$

Dilution of Mud System

$$\text{Vwm} = \frac{\text{Vm}\,(\text{Fct} - \text{Fcop})}{\text{Fcop} - \text{Fca}}$$

where Vwm = barrels of dilution water or mud required
Vm = barrels of mud in circulating system
Fct = percent low gravity solids in system
Fcop = percent total optimum low gravity solids desired
Fca = percent low gravity solids (bentonite and/or chemicals added)

Example: 1000 bbl of mud in system. Total LGS = 6%. Reduce solids to 4%. Dilute with water:

$$\text{Vwm} = \frac{1000\,(6 - 4)}{4}$$

$$\text{Vwm} = \frac{2000}{4}$$

$$\text{Vwm} = 500\,\text{bbl}$$

If dilution is done with a 2% bentonite slurry, the total would be:

$$\text{Vwm} = \frac{1000\,(6 - 4)}{4}$$

$$\text{Vwm} = \frac{2000}{2}$$

$$\text{Vwm} = 1000\,\text{bbl}$$

Displacement—Barrels of Water/Slurry Required

$$Vwm = \frac{Vm\,(Fct - Fcop)}{Fct - Fca}$$

where Vwm = barrels of mud to be jetted and water or slurry to be added to maintain constant circulating volume:

Example: 1000 bbl in mud system. Total LGS = 6%. Reduce solids to 4%:

$$Vwm = \frac{1000(6 - 4)}{6}$$

$$Vwm = \frac{2000}{6}$$

$$Vwm = 333\,\text{bbl}$$

If displacement is done by adding 2% bentonite slurry, the total volume would be:

$$Vwm = \frac{1000(6 - 4)}{6 - 2}$$

$$Vwm = \frac{2000}{4}$$

$$Vwm = 500\,\text{bbl}$$

Evaluation of Hydrocyclone

Determine the mass of solids (for an unweighted mud) and the volume of water discarded by one cone of a hydrocyclone (desander or desilter):

Volume fraction of solids (SF):

$$SF = \frac{MW - 8.22}{13.37}$$

Mass rate of solids (MS):

$$MS = 19{,}530 \times SF \times \frac{V}{T}$$

Volume rate of water (WR)

$$WR = 900\,(1 - SF)\frac{V}{T}$$

where SF = fraction percentage of solids
MW = average density of discarded mud, ppg
MS = mass rate of solids removed by one cone of a hydrocyclone, lb/hr
V = volume of slurry sample collected, quarts
T = time to collect slurry sample, seconds
WR = volume of water ejected by one cone of a hydrocyclone, gal/hr

Example: Average weight of slurry sample collected = 16.0 ppg
Sample collected in 45 seconds
Volume of slurry sample collected = 2 quarts

a) Volume fraction of solids:

$$SF = \frac{16.0 - 8.33}{13.37}$$

$$SF = 0.5737$$

b) Mass rate of solids:

$$MS = 19{,}530 \times 0.5737 \times \frac{2}{45}$$

$$MS = 11{,}204.36 \times 0.0444$$

$$MS = 497.97\,\text{lb/hr}$$

c) Volume rate of water:

$$WR = 900\,(1 - 0.5737)\frac{2}{45}$$

$$WR = 900 \times 0.4263 \times 0.0444$$

$$WR = 17.0\,\text{gal/hr}$$

Evaluation of Centrifuge

a) Underflow mud volume:

$$QU = \frac{[QM \times (MW - PO)] - [QW \times (PO - PW)]}{PU - PO}$$

b) Fraction of old mud in underflow:

$$FU = \frac{35 - PU}{35 - MW + \left(\frac{QW}{QM}\right) \times (35 - PW)}$$

c) Mass rate of clay:

$$QC = \frac{CC \times [QM - (QU \times FU)]}{42}$$

d) Mass rate of additives:

$$QC = \frac{CD \times [QM - (QU \times FU)]}{42}$$

e) Water flow rate into mixing pit:

$$QP = \frac{[QM \times (35 - MW)] - [QU \times (35 - PU)] - (0.6129 \times QC) - (0.6129 \times QD)}{35 - PW}$$

f) Mass rate for API barite:

$$QB = QM - QU - QP - \frac{QC}{21.7} - \frac{QD}{21.7} \times 35$$

where MW = mud density into centrifuge, ppg
QM = mud volume into centrifuge, gal/min
PW = dilution water density, ppg
QW = dilution water volume, gal/min
PU = underflow mud density, ppg
PO = overflow mud density, ppg
CC = clay content in mud, lb/bbl
CD = additive content in mud, lb/bbl
QU = underflow mud volume, gal/min

FU = fraction of old mud in underflow
QC = mass rate of clay, lb/min
QD = mass rate of additives, lb/min
QP = water flow rate into mixing pit, gal/min
QB = mass rate of API barite, lb/min

Example: Mud density into centrifuge (MW) = 16.2 ppg
Mud volume into centrifuge (QM) = 16.5 gal/min
Dilution water density (PW) = 8.34 ppg
Dilution water volume (QW) = 10.5 gal/min
Underflow mud density (PU) = 23.4 ppg
Overflow mud density (PO) = 9.3 ppg
Clay content of mud (CC) = 22.5 lb/bbl
Additive content of mud (CD) = 6 lb/bbl

Determine: Flow rate of underflow
Volume fraction of old mud in the underflow
Mass rate of clay into mixing pit
Mass rate of additives into mixing pit
Water flow rate into mixing pit
Mass rate of API barite into mixing pit

a) Underflow mud volume, gal/min:

$$QU = \frac{[16.5 \times (16.2 - 9.3)] - [10.5 \times (9.3 - 8.34)]}{23.4 - 9.3}$$

$$QU = \frac{113.85 - 10.08}{14.1}$$

$$QU = 7.4 \text{ gal/min}$$

b) Volume fraction of old mud in the underflow:

$$FU = \frac{35 - 23.4}{35 - 16.2 + \left[\frac{10.5}{16.5} \times (35 - 8.34)\right]}$$

$$FU = \frac{11.6}{18.8 + (0.63636 \times 26.66)}$$

$$FU = 0.324\%$$

c) Mass rate of clay into mixing pit, lb/min:

$$QC = \frac{22.5 \times [16.5 - (7.4 \times 0.324)]}{42}$$

$$QC = \frac{22.5 \times 14.1}{42}$$

$$QC = 7.55 \text{ lb/min}$$

d) Mass rate of additives into mixing pit, lb/min:

$$QD = \frac{6 \times [16.5 - (7.4 \times 0.324)]}{42}$$

$$QD = \frac{6 \times 14.1}{42}$$

$$QD = 2.01 \text{ lb/min}$$

e) Water flow into mixing pit, gal/min:

$$\begin{aligned} QP = {} & [16.5 \times (35 - 16.2)] - [7.4 \times (35 - 23.4)] \\ & - (0.6129 \times 7.55) - (0.6129 \times 2) \div (35 - 8.34) \end{aligned}$$

$$QP = \frac{310.2 - 85.84 - 4.627 - 1.226}{26.66}$$

$$QP = \frac{218.507}{26.66}$$

$$QP = 8.20 \text{ gal/min}$$

f) Mass rate of API barite into mixing pit, lb/min:

$$QB = 16.5 - 7.4 - 8.20 - \frac{7.55}{21.7} - \frac{2.01}{21.7} \times 35$$

$$QB = 16.5 - 7.4 - 8.20 - 0.348 - 0.0926 \times 35$$

$$QB = 0.4594 \times 35$$

$$QB = 16.079 \text{ lb/min}$$

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Manual of Drilling Fluids Technology, Baroid Division, N.L. Petroleum Services, Houston, Texas, 1979.

Mud Facts Engineering Handbook, Milchem Incorporated, Houston, Texas, 1984.

CHAPTER FOUR

PRESSURE CONTROL

Kill Sheets and Related Calculations

Normal kill sheet

Prerecorded data

Original mud weight (OMW) ______________________________ ppg
Measured depth (MD) ______________________________ ft
Kill rate pressure (KRP) ______________ psi @ ______________ spm
Kill rate pressure (KRP) ______________ psi @ ______________ spm

Drill string volume

Drill pipe capacity
____________ bbl/ft × ____________ length, ft = ____________ bbl
Drill pipe capacity
____________ bbl/ft × ____________ length, ft = ____________ bbl
Drill collar capacity
____________ bbl/ft × ____________ length, ft = ____________ bbl

Total drill string volume ______________________________ bbl

Annular volume

Drill collar/open hole
Capacity __________ bbl/ft × __________ length, ft = __________ bbl
Drill pipe/open hole
Capacity __________ bbl/ft × __________ length, ft = __________ bbl
Drill pipe/casing
Capacity __________ bbl/ft × __________ length, ft = __________ bbl

Total barrels in open hole ______________________________ bbl
Total annular volume ______________________________ bbl

Pump data

Pump output ______________ bbl/stk @ ______________ % efficiency

Surface to bit strokes:

Drill string volume ________ bbl ÷ ________ pump output, bbl/stk = ________ stk

Bit to casing shoe strokes:

Open hole volume ________ bbl ÷ ________ pump output, bbl/stk = ________ stk

Bit to surface strokes:

Annulus volume ________ bbl ÷ ________ pump output, bbl/stk = ________ stk

Maximum allowable shut-in casing pressure:

Leak-off test ____________ psi, using ____________ ppg mud weight @ casing setting depth of ________________________________ TVD

Kick data

SIDPP ____ psi
SICP ____ psi
Pit gain ____ bbl
True vertical depth ______________________________________ ft

Calculations

Kill weight mud (KWM)

= SIDPP ______ psi ÷ 0.052 ÷ TVD ______ ft + OMW ______ ppg
= ____________ ppg

Initial circulating pressure (ICP)

= SIDPP __________ psi + KRP __________ psi = __________ psi

Final circulating pressure (FCP)

= KWM ________ ppg × KRP ________ psi ÷ OMW ________ ppg
= ____________ psi

Psi/stroke

ICP __________ psi − FCP __________ psi ÷ strokes to bit ________
= __________ psi/stk

Pressure Chart

	Strokes	Pressure	
	0		< **Initial Circulating Pressure**
Strokes to Bit >			< **Final Circulating Pressure**

Example: Use the following data and fill out a kill sheet:

Data: Original mud weight	= 9.6 ppg
Measured depth	= 10,525 ft
Kill rate pressure @ 50 spm	= 1000 psi
Kill rate pressure @ 30 spm	= 600 psi
Drill string:	
drill pipe 5.0 in.—19.5 lb/ft	
capacity	= 0.01776 bbl/ft
HWDP 5.0 in. 49.3 lb/ft	
capacity	= 0.00883 bbl/ft
length	= 240 ft
drill collars 8.0 in. OD—3.0 in. ID	
capacity	= 0.0087 bbl/ft
length	= 360 ft
Annulus:	
hole size	= 12 1/4 in.
drill collar/open hole capacity	= 0.0836 bbl/ft
drill pipe/open hole capacity	= 0.1215 bbl/ft
drill pipe/casing capacity	= 0.1303 bbl/ft
Mud pump (7 in. × 12 in. triplex @ 95% eff)	= 0.136 bbl/stk
Leak-off test with 9.0 ppg mud	= 1130 psi
Casing setting depth	= 4000 ft

Shut-in drill pipe pressure	= 480 psi
Shut-in casing pressure	= 600 psi
Pit volume gain	= 35 bbl
True vertical depth	= 10,000 ft

Calculations

Drill string volume:

Drill pipe capacity

0.01776 bbl/ft × 9925 ft = 176.27 bbl

HWDP capacity

0.00883 bbl/ft × 240 ft = 2.12 bbl

Drill collar capacity

0.0087 bbl/ft × 360 ft = 3.13 bbl

Total drill string volume = 181.5 bbl

Annular volume:

Drill collar/open hole

0.0836 bbl/ft × 360 ft = 30.1 bbl

Drill pipe/open hole

0.1215 bbl/ft × 6165 ft = 749.05 bbl

Drill pipe/casing

0.1303 bbl/ft × 4000 ft = 521.2 bbl

Total annular volume = 1300.35 bbl

Strokes to bit:

Drill string volume 181.5 bbl ÷ 0.136 bbl/stk

Strokes to bit = 1335 stk

Bit-to-casing strokes:

Open-hole volume = 779.15 bbl ÷ 0.136 bbl/stk

Bit-to-casing strokes = **5729 stk**

Bit-to-surface strokes:

Annular volume = 1300.35 bbl ÷ 0.136 bbl/stk

Bit-to-surface strokes = **9561 stk**

Kill weight mud (KWM)

480 psi ÷ 0.052 ÷ 10,000 ft + 9.6 ppg = 10.5 ppg

Initial circulating pressure (ICP)

480 psi ÷ 1000 psi = 1480 psi

Final circulating pressure (FCP)

10.5 ppg × 1000 psi ÷ 9.6 ppg = 1094 psi

Pressure chart

Strokes to bit = 1335 ÷ 10 = 133.5
Therefore, strokes will increase by 133.5 per line:

Pressure Chart

	Strokes	Pressure
	0	
133.5 rounded up	134	
133.5 + **133.5** =	267	
+ **133.5** =	401	
+ **133.5** =	534	
+ **133.5** =	668	
+ **133.5** =	801	
+ **133.5** =	935	
+ **133.5** =	1068	
+ **133.5** =	1202	
+ **133.5** =	1335	

Pressure

ICP (1480) psi – FCP (1094) ÷ 10 = 38.6 psi

Therefore, the pressure will decrease by 38.6 psi per line.

Pressure Chart

	Strokes	Pressure	
	0	1480	< **ICP**
1480 – 38.6 =		1441	
– 38.6 =		1403	
– 38.6 =		1364	
– 38.6 =		1326	
– 38.6 =		1287	
– 38.6 =		1248	
– 38.6 =		1210	
– 38.6 =		1171	
– 38.6 =		1133	
– 38.6 =		1094	< **FCP**

Trip margin (TM)

TM = Yield point ÷ 11.7(Dh, in. – Dp, in.)

Example: Yield point = 10 lb/100 sq ft; Dh = 8.5 in.; Dp = 4.5 in.

TM = 10 ÷ 11.7(8.5 – 4.5)
TM = 0.2 ppg

Determine psi/stk

$$\text{psi/stk} = \frac{\text{ICP} - \text{FCP}}{\text{strokes to bit}}$$

Example: Using the kill sheet just completed, adjust the pressure chart to read in increments that are easy to read on pressure gauges. Example: 50 psi:

Data: Initial circulating pressure = 1480 psi
Final circulating pressure = 1094 psi
Strokes to bit = 1335 psi

$$\text{psi/stk} = \frac{1480 - 1094}{1335}$$

psi/stk = 0.2891

The pressure side of the chart will appear as follows:

Pressure Chart

Strokes	Pressure
0	1480
	1450
	1400
	1350
	1300
	1250
	1200
	1150
	1100
	1094

Adjust the strokes as necessary.

For line 2: How many strokes will be required to decrease the pressure from 1480 psi to 1450 psi?

1480 psi − 1450 psi = 30 psi

30 psi ÷ 0.2891 psi/stk = 104 strokes

For lines 3 to 7: How many strokes will be required to decrease the pressure by 50 psi increments?

50 psi ÷ 0.2891 psi/stk = 173 strokes

Therefore, the new pressure chart will appear as follows:

Pressure Chart

	Strokes	Pressure
	0	1480
104	104	1450
104 + 173 =	277	1400
+ 173 =	450	1350
+ 173 =	623	1300
+ 173 =	796	1250
+ 173 =	969	1200
+ 173 =	1142	1150
+ 173 =	1315	1100
	1335	1094

Kill sheet with a tapered string

$$\text{psi @ \_\_\_\_ strokes} = \text{ICP} - \left[\left(\frac{\text{DPL}}{\text{DSL}}\right) \times (\text{ICP} - \text{FCP})\right]$$

Note: Whenever a kick is taken with a *tapered drill string* in the hole, interim pressures should be calculated for a) the length of large drill pipe (DPL) and b) the length of large drill pipe plus the length of small drill pipe.

Example: Drill pipe 1: 5.0 in.—19.5 lb/ft
capacity = 0.01776 bbl/ft
length = 7000 ft
Drill pipe 2: 3-1/2 in.—13.3 lb/ft
capacity = 0.0074 bbl/ft
length = 6000 ft
Drill collars: 4 1/2 in.—OD × 1-1/2 in. ID
capacity = 0.0022 bbl/ft
length = 2000 ft
Pump output = 0.117 bbl/stk

Step 1

Determine strokes:

$$7000\,\text{ft} \times 0.01776\,\text{bbl/ft} \div 0.117\,\text{bbl/stk} = 1063$$
$$6000\,\text{ft} \times 0.00742\,\text{bbl/ft} \div 0.117\,\text{bbl/stk} = 381$$
$$2000\,\text{ft} \times 0.0022\,\text{bbl/ft} \div 0.117\,\text{bbl/stk} = 38$$

Total strokes = 1482

Data from kill sheet

Initial drill pipe circulating pressure (ICP) = 1780 psi
Final drill pipe circulating pressure (FCP) = 1067 psi

Step 2

Determine interim pressure for the 5.0 in. drill pipe at 1063 strokes:

$$\text{psi @ 1063 strokes} = 1780 - \left[\left(\frac{7000}{15{,}000}\right) \times (1780 - 1067)\right]$$
$$= 1780 - (0.4666 \times 713)$$
$$= 1780 - 333$$
$$= 1447\,\text{psi}$$

Step 3

Determine interim pressure for 5.0 in. plus 3-1/2 in. drill pipe (1063 + 381) = 1444 strokes:

$$\text{psi @ 1444 strokes} = 1780 - \left[\left(\frac{13{,}000}{15{,}000}\right) \times (1780 - 1067)\right]$$
$$= 1780 - (0.86666 \times 713)$$
$$= 1780 - 618$$
$$= 1162\,\text{psi}$$

Step 4

Plot data on graph paper:

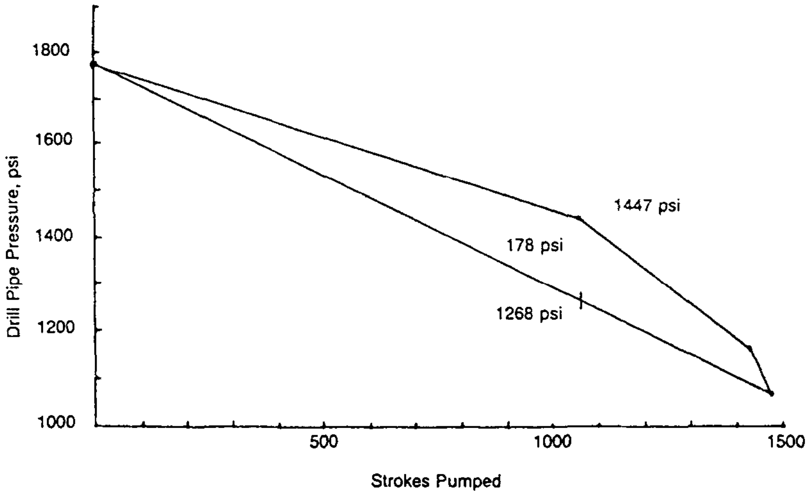

Figure 4-1. Data from kill sheet.

Note: After pumping 1062 strokes, if a straight line would have been plotted, the well would have been underbalanced by 178 psi.

Kill sheet for a highly deviated well

Whenever a kick is taken in a highly deviated well, the circulating pressure can be excessive when the kill weight mud gets to the kick-off point (KOP). If the pressure is excessive, the pressure schedule should be divided into two sections: 1) from surface to KOP, and 2) from KOP to TD. The following calculations are used:

Determine strokes from surface to KOP:

$$\text{Strokes} = \frac{\text{drill pipe}}{\text{capacity, bbl/ft}} \times \frac{\text{measured depth}}{\text{to KOP, ft}} \div \frac{\text{pump output,}}{\text{bbl/stk}}$$

Determine strokes from KOP to TD:

$$\text{Strokes} = \frac{\text{drill string}}{\text{capacity, bbl/ft}} \times \frac{\text{measured depth}}{\text{to TD, ft}} \div \frac{\text{pump output,}}{\text{bbl/stk}}$$

Kill weight mud:

$$\text{KWM} = \text{SIDPP} \div 0.052 \div \text{TVD} + \text{OMW}$$

Initial circulating pressure:

$$\text{ICP} = \text{SIDPP} + \text{KRP}$$

Final circulating pressure:

$$\text{FCP} = \text{KWM} \times \text{KRP} \div \text{OMW}$$

Hydrostatic pressure increase from surface to KOP:

$$\text{psi} = (\text{KWM} - \text{OMW}) \times 0.052 \times \text{TVD @ KOP}$$

Friction pressure increase to KOP:

$$\text{FP} = (\text{FCP} - \text{KRP}) \times \text{MD @ KOP} \div \text{MD @ TD}$$

Circulating pressure when KWM gets to KOP:

$$\text{CP @ KOP} = \text{ICP} - \text{HP increase to KOP} + \begin{array}{l}\text{friction pressure}\\ \text{increase, 1}\end{array}$$

Note: At this point, compare this circulating pressure to the value obtained when using a regular kill sheet.

Example:

Original mud weight (OMW)	= 9.6 ppg
Measured depth (MD)	= 15,000 ft
Measured depth @ KOP	= 5000 ft
True vertical depth @ KOP	= 5000 ft
Kill rate pressure (KRP) @ 30 spm	= 600 psi
Pump output	= 0.136 bbl/stk
Drill pipe capacity	= 0.01776 bbl/ft
Shut-in drill pipe pressure (SIDPP)	= 800 psi
True vertical depth (TVD)	= 10,000 ft

Solution:

Strokes from surface to KOP:

Strokes = 0.01776 bbl/ft × 5000 ft ÷ 0.136 bbl/stk
Strokes = 653

Strokes from KOP to TD:

Strokes = 0.01776 bbl/ft × 10,000 ft ÷ 0.136 bbl/stk
Strokes = 1306

Total strokes from surface to bit:

Surface to bit strokes = 653 + 1306
Surface to bit strokes = 1959

Kill weight mud (KWM):

KWM = 800 psi ÷ 0.052 ÷ 10,000 ft + 9.6 ppg
KWM = 11.1 ppg

Initial circulating pressure (ICP):

ICP = 800 psi + 600 psi
ICP = 1400 psi

Final circulating pressure (FCP):

FCP = 11.1 ppg × 600 psi ÷ 9.6 ppg
FCP = 694 psi

Hydrostatic pressure increase from surface to KOP:

HPi = (11.1 − 9.6) × 0.052 × 5000
HPi = 390 psi

Friction pressure increase to TD:

FP = (694 − 600) × 5000 ÷ 15,000
FP = 31 psi

Circulating pressure when KWM gets to KOP:

CP = 1400 − 390 + 31
CP = 1041 psi

Compare this circulating pressure to the value obtained when using a regular kill sheet:

psi/stk = 1400 − 694 ÷ 1959
psi/stk = 0.36

0.36 psi/stk × 653 strokes = 235 psi

1400 − 235 = 1165 psi

Using a regular kill sheet, the circulating drill pipe pressure would be 1165 psi. The adjusted pressure chart would have 1041 psi on the drill pipe gauge. This represents 124 psi difference in pressure, which would also be observed on the annulus (casing) side. If the difference in pressure at the KOP is 100 psi or greater, then the adjusted pressure chart should be used to minimize the chances of losing circulation.

The chart below graphically illustrates the difference:

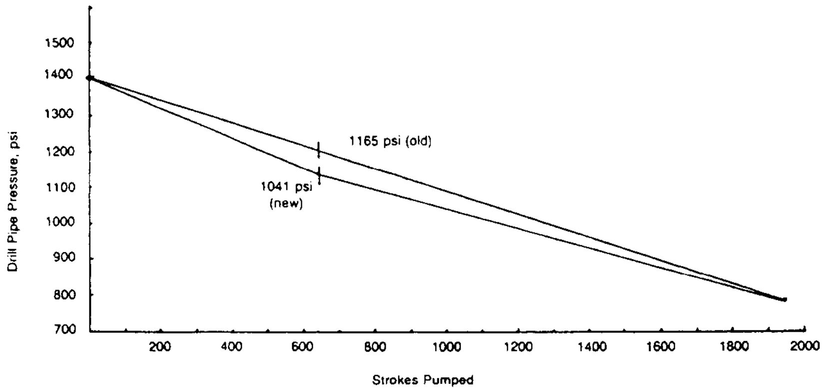

Figure 4-2. Adjusted pressure chart.

Prerecorded Information

Maximum anticipated surface pressure

Two methods are commonly used to determine maximum anticipated surface pressure:

Method 1: Use when assuming the maximum formation pressure is from TD:

Step 1

Determine maximum formation pressure (FPmax):

$$\text{FP max} = \begin{pmatrix} \text{maximum} & & \text{safety} \\ \text{mud wt to} & + & \text{factor,} \\ \text{be used, ppg} & & \text{ppg} \end{pmatrix} \times 0.052 \times \begin{pmatrix} \text{total} \\ \text{depth,} \\ \text{ft} \end{pmatrix}$$

Step 2

Assuming 100% of the mud is blown out of the hole, determine the hydrostatic pressure in the wellbore:

Note: 70% to 80% of mud being blown out is sometimes used instead of 100%.

HPgas = gas gradient, psi/ft × total depth, ft

Step 3

Determine maximum anticipated surface pressure (MASP):

MASP = FPmax − HPgas

Example:	Proposed total depth	= 12,000 ft
	Maximum mud weight to be used in drilling well	= 12.0 ppg
	Safety factor	= 4.0 ppg
	Gas gradient	= 0.12 psi/ft

Assume that 100% of mud is blown out of well.

Step 1

FPmax = (12.0 + 4.0) × 0.052 × 12,000 ft
FPmax = 9984 psi

Step 2

HPgas = 0.12 × 12,000 ft
HPgas = 1440 psi

Step 3

MASP = 9984 − 1440
MASP = 8544 psi

Method 2: Use when assuming the maximum pressure in the wellbore is attained when the formation at the shoe fractures:

Step 1

Determine fracture pressure, psi:

$$\text{Fracture pressure, psi} = \left(\begin{array}{l}\text{estimated}\\ \text{fracture}\\ \text{gradient,}\\ \text{ppg}\end{array} + \begin{array}{l}\text{safety}\\ \text{factor,}\\ \text{ppg}\end{array}\right) \times 0.052 \times \left(\begin{array}{l}\text{casing}\\ \text{shoe}\\ \text{TVD,}\\ \text{ft}\end{array}\right)$$

Note: A safety factor is added to ensure the formation fractures before BOP pressure rating is exceeded.

Step 2

Determine the hydrostatic pressure of gas in the wellbore (HPgas):

HPgas = gas gradient, psi/ft × casing shoe TVD, ft

Step 3

Determine the maximum anticipated surface pressure (MASP), psi:

Example: Proposed casing setting depth = 4000 ft
Estimated fracture gradient = 14.2 ppg
Safety factor = 1.0 ppg
Gas gradient = 0.12 psi/ft

Assume 100% of mud is blown out of the hole.

Step 1

Fracture pressure, psi = (14.2 + 1.0) × 0.052 × 4000 ft

Fracture pressure = 3162 psi

Step 2

HPgas = 0.12 × 4000 ft
HPgas = 480 psi

Step 3

MASP = 3162 − 480
MASP = 2682 psi

Sizing diverter lines

Determine diverter line inside diameter, in., equal to the area between the inside diameter of the casing and the outside diameter of drill pipe in use:

Diverter line ID, in. = $\sqrt{Dh^2 - Dp^2}$

Example:

Casing—13-3/8 in. – J-55 – 61 lb/ft ID = 12.515 in.
Drill pipe—19.5 lb/ft OD = 5.0 in.

Determine the diverter line inside diameter that will equal the area between the casing and drill pipe:

Diverter line ID, in. = $\sqrt{12.515^2 - 5.0^2}$

Diverter line ID = 11.47 in.

Formation pressure tests

Two methods of testing:

- Equivalent mud weight test
- Leak-off test

Precautions to be undertaken before testing:

1. Circulate and condition the mud to ensure the mud weight is consistent throughout the system.
2. Change the pressure gauge (if possible) to a smaller increment gauge so a more accurate measure can be determined.
3. Shut-in the well.
4. Begin pumping at a very slow rate—1/4 to 1/2 bbl/min.
5. Monitor pressure, time, and barrels pumped.
6. Some operators may use different procedures in running this test; others may include:
   a. Increasing the pressure by 100 psi increments, waiting for a few minutes, then increasing by another 100 psi, and so on, until either the equivalent mud weight or leak-off is achieved.
   b. Some operators prefer not pumping against a closed system. They prefer to circulate through the choke and increase back pressure by slowly closing the choke. In this method, the annular pressure loss should be calculated and added to the test pressure results.

Testing to an equivalent mud weight:

1) This test is used primarily on development wells where the maximum mud weight that will be used to drill the next interval is known.
2) Determine the equivalent test mud weight, ppg. Two methods are normally used.

Method 1: Add a value to the maximum mud weight that is needed to drill the interval.

Example: Maximum mud weight necesary to drill the next interval = 11.5 ppg plus safety factor = 1.0 ppg

$$\text{Equivalent test mud weight, ppg} = \begin{pmatrix}\text{maximum mud}\\ \text{weight, ppg}\end{pmatrix} + \begin{pmatrix}\text{safety}\\ \text{factor, ppg}\end{pmatrix}$$

$$\text{Equivalent test mud weight} = 11.5\,\text{ppg} + 1.0\,\text{ppg}$$

$$\text{Equivalent test mud weight} = 12.5\,\text{ppg}$$

Method 2: Subtract a value from the estimated fracture gradient for the depth of the casing shoe.

$$\text{Equivalent test mud weight} = \begin{pmatrix}\text{estimated fracture}\\ \text{gradient, ppg}\end{pmatrix} - \begin{pmatrix}\text{safety}\\ \text{factor}\end{pmatrix}$$

Example: Estimated formation fracture gradient = 14.2 ppg. Safety factor = 1.0 ppg

$$\text{Equivalent test mud weight} = 14.2\,\text{ppg} - 1.0\,\text{ppg}$$

Determine surface pressure to be used:

$$\text{Surface pressure, psi} = \begin{pmatrix}\text{equiv. test mud wt, ppg} - \begin{matrix}\text{mud wt}\\ \text{in use,}\\ \text{ppg}\end{matrix}\end{pmatrix} \times 0.052 \times \begin{pmatrix}\text{casing}\\ \text{seat}\\ \text{TVD, ft}\end{pmatrix}$$

Example:

Mud weight = 9.2 ppg
Casing shoe TVD = 4000 ft
Equivalent test mud weight = 13.2 ppg

Solution: Surface pressure = (13.2 − 9.2) × 0.052 × 4000 ft
Surface pressure = 832 psi

Testing to leak-off text:

1) This test is used primarily on wildcat or exploratory wells or where the actual fracture is not known.
2) Determine the estimated fracture gradient from a "Fracture Gradient Chart."
3) Determine the estimated leak-off pressure.

$$\text{Estimated leak-off pressure} = \begin{pmatrix}\text{estimated} & & \text{mud wt} \\ \text{fracture} & - & \text{in use,} \\ \text{gradient} & & \text{ppg}\end{pmatrix} \times 0.052 \times \begin{pmatrix}\text{casing} \\ \text{seat} \\ \text{TVD, ft}\end{pmatrix}$$

Example: Mud weight = 9.6 ppg
Casing shoe TVD = 4000 ft
Estimated fracture gradient = 14.4 ppg

Solution: Estimated leak-off pressure = (14.4 − 9.6) × 0.052 × 4000 ft
= 4.8 × 0.052 × 4000
Estimated leak-off pressure = 998 psi

Maximum allowable mud weight from leak-off test data

$$\text{Max allowable mud weight, ppg} = \begin{pmatrix}\text{leak-off} \\ \text{pressure,} \\ \text{psi}\end{pmatrix} \div 0.052 \div \begin{pmatrix}\text{casing} \\ \text{shoe} \\ \text{TVD, ft}\end{pmatrix} + \begin{pmatrix}\text{mud wt} \\ \text{in use,} \\ \text{ppg}\end{pmatrix}$$

Example: Determine the maximum allowable mud weight, ppg, using the following data:

Leak-off pressure = 1040 psi
Casing shoe TVD = 4000 ft
Mud weight in use = 10.0 ppg

$$\text{Max allowable mud weight, ppg} = 1040 \div 0.052 \div 4000 + 10.0$$

$$\text{Max allowable mud weight, ppg} = 15.0\,\text{ppg}$$

Maximum allowable shut-in casing pressure (MASICP) also called maximum allowable shut-in annular pressure (MASP):

$$\text{MASICP} = \left(\begin{array}{l}\text{maximum}\\ \text{allowable}\\ \text{mud wt, ppg}\end{array} - \begin{array}{l}\text{mud wt}\\ \text{in use,}\\ \text{ppg}\end{array}\right) \times 0.052 \times \left(\begin{array}{l}\text{casing}\\ \text{show}\\ \text{TVD, ft}\end{array}\right)$$

Example: Determine the maximum allowable shut-in casing pressure using the following data:

Maximum allowable mud weight	= 15.0 ppg
Mud weight in use	= 12.2 ppg
Casing shoe TVD	= 4000 ft

MASICP = (15.0 − 12.2) × 0.052 × 4000 ft
MASICP = 582 psi

Kick tolerance factor (KTF)

$$\text{KTF} = \left(\begin{array}{l}\text{casing}\\ \text{shoe}\\ \text{TVD, ft}\end{array} \div \begin{array}{l}\text{well}\\ \text{depth}\\ \text{TVD, ft}\end{array}\right) \times \left(\begin{array}{l}\text{maximum}\\ \text{allowable}\\ \text{mud wt, ppg}\end{array} - \begin{array}{l}\text{mud wt}\\ \text{in use,}\\ \text{ppg}\end{array}\right)$$

Example: Determine the kick tolerance factor (KTF) using the following data:

Maximum allowable mud weight (from leak-off test data)	= 14.2 ppg
Mud weight in use	= 10.0 ppg
Casing shoe TVD	= 4000 ft
Well depth TVD	= 10,000 ft

KTF = (4000 ft ÷ 10,000 ft) × (14.2 ppg − 10.0 ppg)
KTF = 1.68 ppg

Maximum surface pressure from kick tolerance data

$$\text{Maximum surface pressure} = \text{kick tolerance factor, ppg} \times 0.052 \times \text{TVD, ft}$$

Example: Determine the maximum surface pressure, psi, using the following data:

$$\text{Maximum surface pressure} = 1.68\,\text{ppg} \times 0.052 \times 10{,}000\,\text{ft}$$

$$\text{Maximum surface pressure} = 874\,\text{psi}$$

Maximum formation pressure (FP) that can be controlled when shutting-in a well

$$\text{Maximum FP, psi} = \left(\begin{array}{l}\text{kick} \\ \text{tolerance} \\ \text{factor, ppg}\end{array} + \begin{array}{l}\text{mud wt} \\ \text{in use,} \\ \text{ppg}\end{array}\right) \times 0.052 \times \text{TVD, ft}$$

Example: Determine the maximum formation pressure (FP) that can be controlled when shutting-in a well, using the following data:

Data: Kick tolerance factor = 1.68 ppg
Mud weight = 10.0 ppg
True vertical depth = 10,000 ft

$$\text{Maximum FP, psi} = (1.68\,\text{ppg} + 10.0\,\text{ppg}) \times 0.052 \times 10{,}000\,\text{ft}$$

$$\text{Maximum FP} = 6074\,\text{psi}$$

Maximum influx height possible to equal maximum allowable shut-in casing pressure (MASICP)

$$\text{Influx height, ft} = \text{MASICP, psi} \div \left(\begin{array}{l}\text{gradient} \\ \text{of mud wt} \\ \text{in use,} \\ \text{pis/ft}\end{array} - \begin{array}{l}\text{influx} \\ \text{gradient} \\ \text{psi/ft}\end{array}\right)$$

Example: Determine the influx height, ft, necessary to equal the maximum allowable shut-in casing pressure (MASICP), using the following data:

Data: Maximum allowable shut-in casing pressure = 874 psi
Mud gradient (10.0 ppg × 0.052) = 0.52 psi/ft
Gradient of influx = 0.12 psi/ft

Influx height = 874 psi ÷ (0.52 psi/ft − 0.12 psi/ft)
Influx height = 2185 ft

Maximum influx, barrels to equal maximum allowable shut-in casing pressure (MASICP)

Example:

Maximum influx height to equal MASICP (from above example) = 2185 ft
Annular capacity − drill collars/open hole (12-1/4 in. × 8.0 in.) = 0.0836 bbl/ft
Drill collar length = 500 ft
Annular capacity − drill pipe/open hole (12-1/4 in. × 5.0 in.) = 0.1215 bbl/ft

Step 1

Determine the number of barrels opposite drill collars:

Barrels = 0.0836 bb/ft × 500 ft
Barrels = 41.8

Step 2

Determine the number of barrels opposite drill pipe:

Influx height, ft, opposite drill pipe:

ft = 2185 ft − 500 ft
ft = 1685

Barrels opposite drill pipe:

Barrels = 1685 ft × 0.1215 bbl/ft
Barrels = 204.7

Step 3

Determine maximum influx, bbl, to equal maximum allowable shut-in casing pressure:

Maximum influx = 41.8 bbl + 204.7 bbl
Maximum influx = 246.5 bbl

Adjusting maximum allowable shut-in casing pressure for an increase in mud weight

$$\text{MASICP} = P_L - [D \times (\text{mud wt}_2 - \text{mud wt}_1)]\ 0.052$$

where MASICP = maximum allowable shut-in casing (annulus) pressure, psi
P_L = leak-off pressure, psi
D = true vertical depth to casing shoe, ft
Mud wt_2 = new mud wt, ppg
Mud wt_1 = original mud wt, ppg

Example: Leak-off pressure at casing setting depth (TVD) of 4000 ft was 1040 psi with 10.0 ppg in use. Determine the maximum allowable shut-in casing pressure with a mud weight of 12.5 ppg:

MASICP = 1040 psi − [4000 × (12.5 − 10.0) 0.052]
MASICP = 1040 psi − 520
MASICP = 520 psi

Kick Analysis

Formation pressure (FP) with the well shut-in on a kick

FP, psi = SIDPP, psi + [mud wt, ppg × 0.052 × TVD, ft)

Example: Determine the formation pressure using the following data:

Shut-in drill pipe pressure = 500 psi
Mud weight in drill pipe = 9.6 ppg
True vertical depth = 10,000 ft

FP, psi = 500 psi + (9.6 ppg × 0.052 × 10,000 ft)
FP, psi = 500 psi + 4992 psi
FP = 5492 psi

Bottomhole pressure (BHP) with the well shut-in on a kick

$$\text{BHP, psi} = \text{SIDPP, psi} + (\text{mud wt, ppg} \times 0.052 \times \text{TVD, ft})$$

Example: Determine the bottomhole pressure (BHP) with the well shut-in on a kick:

Shut-in drill pipe pressure = 500 psi
Mud weight in drill pipe = 9.6 ppg
True vertical depth = 10,000 ft

$$\text{BHP, psi} = 500\,\text{psi} + (9.6\,\text{ppg} \times 0.052 \times 10{,}000\,\text{ft})$$
$$\text{BHP, psi} = 500\,\text{psi} + 4992\,\text{psi}$$
$$\text{BHP} = 5492\,\text{psi}$$

Shut-in drill pipe pressure (SIDPP)

$$\text{SIDPP, psi} = \begin{matrix}\text{formation}\\ \text{pressure,}\\ \text{psi}\end{matrix} - (\text{mud wt, ppg} \times 0.052 \times \text{TVD, ft})$$

Example: Determine the shut-in drill pipe pressure using the following data:

Formation pressure = 12,480 psi
Mud weight in drill pipe = 15.0 ppg
True vertical depth = 15,000 ft

$$\text{SIDPP, psi} = 12{,}480\,\text{psi} - (15.0\,\text{ppg} \times 0.052 \times 15{,}000\,\text{ft})$$
$$\text{SIDPP, psi} = 12{,}480\,\text{psi} - 11{,}700\,\text{psi}$$
$$\text{SIDPP} = 780\,\text{psi}$$

Shut-in casing pressure (SICP)

$$\text{SICP} = \left(\begin{matrix}\text{formation}\\ \text{pressure,}\\ \text{psi}\end{matrix}\right) - \left(\begin{matrix}\text{HP of}\\ \text{mud in}\\ \text{annulus, psi}\end{matrix} + \begin{matrix}\text{HP of}\\ \text{influx in}\\ \text{annulus, psi}\end{matrix}\right)$$

Example: Determine the shut-in casing pressure using the following data:

Formation pressure = 12,480 psi
Mud weight in annulus = 15.0 ppg
Feet of mud in annulus = 14,600 ft
Influx gradient = 0.12 psi/ft
Feet of influx in annulus = 400 ft

SICP, psi = 12,480 − [(15.0 × 0.052 × 14,600) + (0.12 × 400)]
SICP, psi = 12,480 − 11,388 + 48
SICP = 1044 psi

Height, ft, of influx

Height of influx, ft = pit gain, bbl ÷ annular capacity, bbl/ft

Example 1: Determine the height, ft, of the influx using the following data:

Pit gain = 20 bbl
Annular capacity − DC/OH = 0.02914 bbl/ft
(Dh = 8.5 in. − Dp = 6.5)

Height of influx, ft = 20 bbl ÷ 0.02914 bbl/ft

Height of influx = 686 ft

Example 2: Determine the height, ft, of the influx using the following data:

Pit gain = 20 bbl
Hole size = 8.5 in.
Drill collar OD = 6.5 in.
Drill collar length = 450 ft
Drill pipe OD = 5.0 in.

Determine annular capacity, bbl/ft, for DC/OH:

$$\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 6.5^2}{1029.4}$$

Annular capacity = 0.02914 bbl/ft

Determine the number of barrels opposite the drill collars:

Barrels = length of collars × annular capacity

Barrels = 450 ft × 0.02914 bbl/ft
Barrels = 13.1

Determine annular capacity, bbl/ft, opposite drill pipe:

$$\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 5.0^2}{1029.4}$$

$$\text{Annular capacity} = 0.0459\,\text{bbl/ft}$$

Determine barrels of influx opposite drill pipe:

Barrels = pit gain, bbl − barrels opposite drill collars

Barrels = 20 bbl − 13.1 bbl
Barrels = 6.9

Determine height of influx opposite drill pipe:

Height, ft = 6.9 bbl ÷ 0.0459 bbl/ft
Height = 150 ft

Determine the total height of the influx:

Height, ft = 450 ft + 150 ft
Height = 600 ft

Estimated type of influx

$$\text{Influx weight, ppg} = \text{mud wt, ppg} - \left(\frac{\text{SICP} - \text{SIDPP}}{\text{height of influx, ft} \times 0.052}\right)$$

then: 1–3 ppg = gas kick
4–6 ppg = oil kick or combination
7–9 ppg = saltwater kick

Example: Determine the type of the influx using the following data:

Shut-in casing pressure = 1044 psi
Shut-in drill pipe pressure = 780 psi
Height of influx = 400 ft
Mud weight = 15.0 ppg

$$\text{Influx weight, ppg} = 15.0\,\text{ppg} - \frac{1044 - 780}{400 \times 0.052}$$

$$= 15.0\,\text{ppg} - \frac{264}{20.8}$$

$$\text{Influx weight} = 2.31\,\text{ppg}$$

Therefore, the influx is probably "gas."

Gas migration in a shut-in well

Estimating the rate of gas migration, ft/hr:

$$Vg = 12e^{(-0.37)(\text{mud wt, ppg})}$$

Vg = rate of gas migration, ft/hr

Example: Determine the *estimated* rate of gas migration using a mud weight of 11.0 ppg:

$$Vg = 12e^{(-0.37)(11.0\text{ ppg})}$$
$$Vg = 12e^{(-4.07)}$$
$$Vg = 0.205\text{ ft/sec}$$
$$Vg = 0.205\text{ ft/sec} \times 60\text{ sec/min}$$
$$Vg = 12.3\text{ ft/min} \times 60\text{ min/hr}$$
$$Vg = 738\text{ ft/hr}$$

Determining the *actual* rate of gas migration after a well has been shut-in on a kick:

$$\text{Rate of gas migration, ft/hr} = \left(\begin{array}{l}\text{increase}\\ \text{in casing}\\ \text{pressure,}\\ \text{psi/hr}\end{array}\right) \div \left(\begin{array}{l}\text{pressure gradient}\\ \text{of mud weight in}\\ \text{use, psi/ft}\end{array}\right)$$

Example: Determine the rate of gas migration with the following data:

Stabilized shut-in casing pressure	= 500 psi
SICP after one hour	= 700 psi
Mud weight	= 12.0 ppg
Pressure gradient for 12.0 ppg mud	= 0.624 psi/ft

Rate of gas migration, ft/hr	= 200 psi/hr ÷ 0.624 psi/ft
Rate of gas migration	= 320.5 ft/hr

Metric calculation

$$\text{Migration rate, m/hr} = \frac{\text{increase in casing pressure, bar/hr}}{\text{drilling fluid density, kg/l} \times 0.0981}$$

S.I. units calculation

$$\text{Migration rate, m/hr} = \frac{\text{increase in casing pressure, kPa/hr} \times 102}{\text{drilling fluid density, kg/m}^3}$$

Hydrostatic pressure decrease at TD caused by gas-cut mud

Method 1:

$$\text{HP decrease, psi} = \frac{100\begin{pmatrix}\text{weight of} & & \text{weight of} \\ \text{uncut mud} & - & \text{gas-cut mud,} \\ \text{ppg} & & \text{ppg}\end{pmatrix}}{\text{weight of gas-cut mud, ppg}}$$

Example: Determine the hydrostatic pressure decrease caused by gas-cut mud using the following data:

Weight of uncut mud = 18.0 ppg
Weight of gas-cut mud = 9.0 ppg

$$\text{HP decrease, psi} = \frac{100 \times (18.0\,\text{ppg} - 9.0\,\text{ppg})}{9.0\,\text{ppg}}$$

HP decrease = 100 psi

Method 2:

$$P = (MG \div C)\,V$$

where P = reduction in bottomhole pressure, psi
MG = mud gradient, psi/ft
C = annular volume, bbl/ft
V = pit gain, bbl

Example: MG = 0.624 psi/ft
C = 0.0459 bbl/ft (Dh = 8.5 in.; Dp = 5.0 in.)
V = 20 bbl

Solution: P = (0.624 psi/ft ÷ 0.0459 bbl/ft) 20
P = 13.59 × 20
P = 271.9 psi

Maximum surface pressure from a gas kick in a water-base mud

$$\text{MSPgk} = 0.2\sqrt{\frac{P \times V \times KWM}{C}}$$

where MSPgk = maximum surface pressure resulting from a gas kick in a water-base mud
P = formation pressure, psi
V = pit gain, bbl
KWM = kill weight mud, ppg
C = annular capacity, bbl/ft

Example: P = 12,480 psi
V = 20 bbl
KWM = 16.0 ppg
C = 0.0505 bbl/ft (Dh = 8.5 in. × Dp = 4.5 in.)

Solution:

$$\text{MSPgk} = 0.2\sqrt{\frac{12,480 \times 20 \times 16.0}{0.0505}}$$

$$= 0.2\sqrt{79,081,188}$$

$$= 0.2 \times 8892.76$$

MSPgk = 1779 psi

Maximum pit gain from gas kick in a water-base mud

$$\text{MPGgk} = 4\sqrt{\frac{P \times V \times C}{KWM}}$$

where MPGgk = maximum pit gain resulting from a gas kick in a water-base mud
P = formation pressure, psi
V = original pit gain, bbl
C = annular capacity, bbl/ft
KWM = kill weight mud, ppg

Example: P = 12,480 psi
V = 20 bbl
C = 0.0505 bbl/ft (8.5 in. × 4.5 in.)
KWM = 16.0 ppg

Solution:

$$MPGgk = 4\sqrt{\frac{12{,}480 \times 20 \times 0.0505}{16.0}}$$

$$= 4\sqrt{787.8}$$

$$= 4 \times 28.068$$

$$MPGgk = 112.3\,\text{bbl}$$

Maximum pressures when circulating out a kick (Moore equations)

The following equations will be used:

1. Determine formation pressure, psi:

   Pb = SIDP + (mud wt, ppg × 0.052 × TVD, ft)

2. Determine the height of the influx, ft:

   hi = pit gain, bbl ÷ annular capacity, bbl/ft

3. Determine pressure exerted by the influx, psi:

   Pi = Pb − [Pm(D − X) + SICP]

4. Determine gradient of influx, psi/ft:

   Ci = Pi ÷ hi

5. Determine Temperature, °R, at depth of interest:

   Tdi = 70°F + (0.012°F/ft. × Di) + 46

6. Determine A for unweighted mud:

   A = Pb − [Pm (D − X) − Pi]

7. Determine pressure at depth of interest:

$$\text{Pdi} = \frac{A}{2} + \left(\frac{A^2}{4} + \frac{\text{pm Pb Zdi T°Rdi hi}}{\text{Zb Tb}}\right)^{1/2}$$

8. Determine kill weight mud, ppg:

   KWM, ppg = SIDPP ÷ 0.052 ÷ TVD, ft + OMW, ppg

9. Determine gradient of kill weight mud, psi/ft:

   pKWM = KWM, ppg × 0.052

10. Determine FEET that drill string volume will occupy in the annulus:

    Di = drill string vol, bbl ÷ annular capacity, bbl/ft

11. Determine A for weighted mud:

    A = Pb − [pm(D − X) − Pi] + [Di (pKWM − pm)]

Example: Assumed conditions:

Well depth	= 10,000 ft
Surface casing	= 9-5/8 in. @ 2500 ft
Casing ID	= 8.921 in.
capacity	= 0.077 bbl/ft
Hole size	= 8.5 in.
Drill pipe	= 4.5 in.–16.6 lb/ft
Drill collar OD	= 6-1/4 in.
length	= 625 ft
Mud weight	= 9.6 ppg
Fracture gradient @ 2500 ft	= 0.73 psi/ft (14.04 ppg)

Mud volumes:

8-1/2 in. hole	= 0.07 bbl/ft
8-1/2 in. hole × 4-1/2 in. drill pipe	= 0.05 bbl/ft
8-1/2 in. hole × 6-1/4 in. drill collars	= 0.032 bbl/ft
8.921 in. casing × 4-1/2 in. drill pipe	= 0.057 bbl/ft
Drill pipe capacity	= 0.014 bbl/ft
Drill collar capacity	= 0.007 bbl/ft
Supercompressibility factor (Z)	= 1.0

The well kicks and the following information is recorded:

SIDP = 260 psi
SICP = 500 psi
Pit gain = 20 bbl

Determine the following:

Maximum pressure at shoe with drillers method
Maximum pressure at surface with drillers method

Maximum pressure at shoe with wait and weight method
Maximum pressure at surface with wait and weight method

Determine maximum pressure at shoe with drillers method:

1. Determine formation pressure:

$Pb = 260\,psi + (9.6\,ppg \times 0.052 \times 10{,}000\,ft)$
$Pb = 5252\,psi$

2. Determine height of influx at TD:

$hi = 20\,bbl \div 0.032\,bbl/ft$
$hi = 625\,ft$

3. Determine pressure exerted by influx at TD:

$Pi = 5252\,psi - [0.4992\,psi/ft\,(10{,}000 - 625) + 500]$
$Pi = 5252\,psi - [4680\,psi + 500]$
$Pi = 5252\,psi - 5180\,psi$
$Pi = 72\,psi$

4. Determine gradient of influx at TD:

$Ci = 72\,psi \div 625\,ft$
$Ci = 0.1152\,psi/ft$

5. Determine height and pressure of influx around drill pipe:

$h = 20\,bbl \div 0.05\,bbl/ft$
$h = 400\,ft$

$Pi = 0.1152\,psi/ft \times 400\,ft$
$Pi = 46\,psi$

6. Determine T °R at TD and at shoe:

$$
\begin{aligned}
T\,°R\ @\ 10{,}000\,ft &= 70 + (0.012 \times 10{,}000) + 460 \\
&= 70 + 120 + 460 \\
T\,°R\ @\ 10{,}000\,ft &= 650 \\
T\,°R\ @\ 2500\,ft &= 70 + (0.012 \times 2500) + 460 \\
&= 70 + 30 + 460 \\
T\,°R\ @\ 2500\,ft &= 560
\end{aligned}
$$

7. Determine A:

$$A = 5252\,\text{psi} - [0.4992\ (10{,}000 - 2500) + 46]$$
$$A = 5252\,\text{psi} - (3744 - 46)$$
$$A = 1462\,\text{psi}$$

8. Determine maximum pressure at shoe with drillers method:

$$P_{2500} = \frac{1462}{2} + \left[\frac{1462^2}{4} + \frac{(0.4992)(5252)(1)(560)(400)}{(1)(650)}\right]^{1/2}$$
$$= 731 + (534{,}361 + 903{,}512)^{1/2}$$
$$= 731 + 1199$$
$$P_{2500} = 1930\,\text{psi}$$

Determine maximum pressure at surface with drillers method:

1. Determine A:

$$A = 5252 - [0.4992\ (10{,}000) + 46]$$
$$A = 5252 - (4992 + 46)$$
$$A = 214\,\text{psi}$$

2. Determine maximum pressure at surface with drillers method:

$$Ps = \frac{214}{2} + \left[\frac{214^2}{4} + \frac{(0.4992)(5252)(530)(400)}{(650)}\right]^{1/2}$$
$$= 107 + (11{,}449 + 855{,}109)^{1/2}$$
$$= 107 + 931$$
$$Ps = 1038\,\text{psi}$$

Determine maximum pressure at shoe with wait and weight method:

1. Determine kill weight mud:

KWM, ppg = 260 psi ÷ 0.052 ÷ 10,000 ft + 9.6 ppg
KWM, ppg = 10.1 ppg

2. Determine gradient (pm), psi/ft for KWM:

pm = 10.1 ppg × 0.052
pm = 0.5252 psi/ft

3. Determine internal volume of drill string:

Drill pipe vol = 0.014 bbl/ft × 9375 ft = 131.25 bbl
Drill collar vol = 0.007 bbl/ft × 625 ft = 4.375 bbl
Total drill string volume = 135.625 bbl

4. Determine FEET drill string volume occupies in annulus:

Di = 135.625 bbl ÷ 0.05 bbl/ft
Di = 2712.5

5. Determine A:

$$A = 5252 - [0.5252\,(10{,}000 - 2500) - 46) + (2715.2\,(0.5252 - 0.4992)]$$
$$A = 5252 - (3939 - 46) + 70.6$$
$$A = 1337.5$$

6. Determine maximum pressure at shoe with wait and weight method:

$$P_{2500} = \frac{1337.5}{2} + \left[\frac{1337.5^2}{4} + \frac{(0.5252)(5252)(1)(560)(400)}{(1)(650)}\right]^{1/2}$$
$$= 668.75 + (447{,}226 + 950{,}569.98)^{1/2}$$
$$= 668.75 + 1182.28$$
$$= 1851 \text{ psi}$$

Determine maximum pressure at surface with wait and weight method:

1. Determine A:

$$A = 5252 - [0.5252(10{,}000) - 46] + [2712.5\,(0.5252 - 0.4992)]$$
$$A = 5252 - (5252 - 46) + 70.525$$
$$A = 24.5$$

2. Determine maximum pressure at surface with wait and weight method:

$$Ps = \frac{24.5}{2} + \left[\frac{24.5^2}{4} + \frac{(0.5252)(5252)(1)(560)(400)}{(1)(650)}\right]^{1/2}$$
$$= 12.25 + (150.0625 + 95069.98)^{1/2}$$
$$= 12.25 + 975.049$$
$$Ps = 987 \text{ psi}$$

Nomenclature:

A = pressure at top of gas bubble, psi
Ci = gradient of influx, psi/ft
D = total depth, ft
Di = feet in annulus occupied by drill string volume
hi = height of influx, ft
MW = mud weight, ppg
Pb = formation pressure, psi
Pdi = pressure at depth of interest, psi
Ps = pressure at surface, psi
Pi = pressure exerted by influx, psi
pKWM = pressure gradient of kill weight mud, ppg
pm = pressure gradient of mud weight in use, ppg
T°F = temperature, degrees Fahrenheit, at depth of interest
T°R = temperature, degrees Rankine, at depth of interest
SIDP = shut-in drill pipe pressure, psi
SICP = shut-in casing pressure, psi
X = depth of interest, ft
Zb = gas supercompressibility factor TD
Zdi = gas supercompressibility factor at depth of interest

Gas flow into the wellbore

Flow rate into the wellbore increases as wellbore depth through a gas sand increases:

$$Q = 0.007 \times md \times Dp \times L \div u \times \ln(Re \div Rw)\ 1440$$

where Q = flow rate, bbl/min
md = permeability, millidarcys
Dp = pressure differential, psi
L = length of section open to wellbore, ft
u = viscosity of intruding gas, centipoise
Re = radius of drainage, ft
Rw = radius of wellbore, ft

Example: md = 200 md
Dp = 624 psi
L = 20 ft
u = 0.3 cp
ln(Re ÷ Rw) = 2.0

$Q = 0.007 \times 200 \times 624 \times 20 \div 0.3 \times 2.0 \times 1440$
$Q = 20\,bbl/min$

Therefore: If one minute is required to shut-in the well, a pit gain of 20 bbl occurs in addition to the gain incurred while drilling the 20-ft section.

Pressure Analysis

Gas expansion equations

Basic gas laws:

$$P_1V_1 \div T_1 = P_2V_2 \div T_2$$

where P_1 = formation pressure, psi
P_2 = hydrostatic pressure at the surface or any depth in the wellbore, psi
V_1 = original pit gain, bbl
V_2 = gas volume at surface or at any depth of interest, bbl
T_1 = temperature of formation fluid, degrees Rankine (°R = °F + 460)
T_2 = temperature at surface or at any depth of interest, degrees Rankine

Basis gas law plus compressibility factor:

$$P_1V_1 \div T_1Z_1 = P_2V_2 \div T_2Z_2$$

where Z_1 = compressibility factor under pressure in formation, dimensionless
Z_2 = compressibility factor at the surface or at any depth of interest, dimensionless

Shortened gas expansion equation:

$$P_1V_1 = P_2V_2$$

where P_1 = formation pressure, psi
P_2 = hydrostatic pressure plus atmospheric pressure (14.7 psi), psi
V_1 = original pit gain, bbl
V_2 = gas volume at surface or at any depth of interest, bbl

Hydrostatic pressure exerted by each barrel of mud in the casing

With pipe in the wellbore:

$$\text{psi/bbl} = \frac{1029.4}{Dh^2 - Dp^2} \times 0.052 \times \text{mud wt, ppg}$$

Example: Dh – 9-5/8 in. casing – 43.5 lb/ft = 8.755 in. ID
Dp = 5.0 in. OD
Mud weight = 10.5 ppg

$$\text{psi/bbl} = \frac{1029.4}{8.755^2 - 5.0^2} \times 0.052 \times 10.5\text{ ppg}$$

$$\text{psi/bbl} = 19.93029 \times 0.052 \times 10.5\text{ ppg}$$

$$\text{psi/bbl} = 10.88$$

With no pipe in the wellbore:

$$\text{psi/bbl} = \frac{1029.4}{ID^2} \times 0.052 \times \text{mud wt ppg}$$

Example: Dh – 9-5/8 in. casing – 43.5 lb/ft = 8.755 in. ID
Mud weight = 10.5 ppg

$$\text{psi/bbl} = \frac{1029.4}{8.755^2} \times 0.052 \times 10.5\text{ ppg}$$

$$\text{psi/bbl} = 13.429872 \times 0.052 \times 10.5\text{ ppg}$$

$$\text{psi/bbl} = 7.33$$

Surface pressure during drill stem tests

Determine formation pressure:

$$\text{psi} = \frac{\text{formation pressure}}{\text{equivalent mud wt, ppg}} \times 0.052 \times \text{TVD, ft}$$

Determine oil hydrostatic pressure:

$$\text{psi} = \text{oil specific gravity} \times 0.052 \times \text{TVD, ft}$$

Determine surface pressure:

$$\text{Surface pressure, psi} = \text{formation pressure, psi} - \text{oil hydrostatic pressure, psi}$$

Example: Oil bearing sand at 12,500 ft with a formation pressure equivalent to 13.5 ppg. If the specific gravity of the oil is 0.5, what will be the static surface pressure during a drill stem test?

Determine formation pressure, psi:

$$\text{FP, psi} = 13.5\,\text{ppg} \times 0.052 \times 12{,}500\,\text{ft}$$

$$\text{FP} = 8775\,\text{psi}$$

Determine oil hydrostatic pressure:

$$\text{psi} = (0.5 \times 8.33) \times 0.052 \times 12{,}500\,\text{ft}$$

$$\text{psi} = 2707$$

Determine surface pressure:

$$\text{Surface pressure, psi} = 8775\,\text{psi} - 2707\,\text{psi}$$

$$\text{Surface pressure} = 6068\,\text{psi}$$

Stripping/Snubbing Calculations

Breakover point between stripping and snubbing

Example: Use the following data to determine the breakover point:

DATA:	Mud weight	= 12.5 ppg
	Drill collars (6-1/4 in. – 2-13/16 in.)	= 83 lb/ft
	Length of drill collars	= 276 ft
	Drill pipe	= 5.0 in.
	Drill pipe weight	= 19.5 lb/ft
	Shut-in casing pressure	= 2400 psi
	Buoyancy factor	= 0.8092

Determine the force, lb, created by wellbore pressure on 6-1/4 in. drill collars:

$$\text{Force, lb} = \begin{pmatrix}\text{pipe or} \\ \text{collar} \\ \text{OD, in}\end{pmatrix}^2 \times 0.7854 \times \begin{pmatrix}\text{wellbore} \\ \text{pressure, psi}\end{pmatrix}$$

$$\text{Force, lb} = 6.25^2 \times 0.7854 \times 2400\,\text{psi}$$

$$\text{Force} = 73{,}631\,\text{lb}$$

Determine the weight, lb, of the drill collars:

$$\text{Wt, lb} = \begin{matrix}\text{drill collar}\\ \text{weight, lb/ft}\end{matrix} \times \begin{matrix}\text{drill collar}\\ \text{length, ft}\end{matrix} \times \begin{matrix}\text{buoyancy}\\ \text{factor}\end{matrix}$$

$$\text{Wt, lb} = 83\,\text{lb/ft} \times 276\,\text{ft} \times 0.8092$$

$$\text{Wt, lb} = 18{,}537\,\text{lb}$$

Additional weight required from drill pipe:

$$\begin{matrix}\text{Drill pipe}\\ \text{weight, lb}\end{matrix} = \begin{matrix}\text{force created}\\ \text{by wellbore}\\ \text{pressure, lb}\end{matrix} - \begin{matrix}\text{drill collar}\\ \text{weight, lb}\end{matrix}$$

$$\begin{matrix}\text{Drill pipe}\\ \text{weight, lb}\end{matrix} = 73{,}631\,\text{lb} - 18{,}537\,\text{lb}$$

$$\begin{matrix}\text{Drill pipe}\\ \text{weight, lb}\end{matrix} = 55{,}094\,\text{lb}$$

Length of drill pipe required to reach breakover point:

$$\begin{matrix}\text{Drill pipe}\\ \text{length, ft}\end{matrix} = \begin{pmatrix}\text{required}\\ \text{drill pipe}\\ \text{weight, lb}\end{pmatrix} \div \begin{pmatrix}\begin{matrix}\text{drill pipe}\\ \text{weight,}\\ \text{lb/ft}\end{matrix} \times \begin{matrix}\text{buoyancy}\\ \text{factor}\end{matrix}\end{pmatrix}$$

$$\begin{matrix}\text{Drill pipe}\\ \text{length, ft}\end{matrix} = 55{,}094\,\text{lb} \div (19.5\,\text{lb/ft} \times 0.8092)$$

$$\begin{matrix}\text{Drill pipe}\\ \text{length, ft}\end{matrix} = 3492\,\text{ft}$$

Length of drill string required to reach breakover point:

$$\begin{matrix}\text{Drill string}\\ \text{length, ft}\end{matrix} = \begin{matrix}\text{drill collar}\\ \text{length, ft}\end{matrix} + \begin{matrix}\text{drill pipe}\\ \text{length, ft}\end{matrix}$$

$$\begin{matrix}\text{Drill string}\\ \text{length, ft}\end{matrix} = 276\,\text{ft} + 3492\,\text{ft}$$

$$\begin{matrix}\text{Drill string}\\ \text{length}\end{matrix} = 3768\,\text{ft}$$

Minimum surface pressure before stripping is possible

$$\text{Minimum surface pressure, psi} = \left(\begin{array}{l}\text{weight of one}\\ \text{stand of collars, lb}\end{array}\right) \div \left(\begin{array}{l}\text{area of drill}\\ \text{collars, sq in.}\end{array}\right)$$

Example: Drill collars—8.0 in. OD × 3.0 in. ID = 147 lb/ft
Length of one stand = 92 ft

$$\text{Minimum surface pressure, psi} = (147\ \text{lb/ft} \times 92\ \text{ft}) \div (8^2 \times 0.7854)$$

$$\text{Minimum surface pressure, psi} = 13{,}524 \div 50.2656\ \text{sq in.}$$

$$\text{Minimum surface pressure} = 269\ \text{psi}$$

Height gain from stripping into influx

$$\text{Height, ft} = \frac{L(Cdp + Ddp)}{Ca}$$

where L = length of pipe stripped, ft
Cdp = capacity of drill pipe, drill collars, or tubing, bbl/ft
Ddp = displacement of drill pipe, drill collars, or tubing, bbl/ft
Ca = annular capacity, bbl/ft

Example: If 300 ft of 5.0 in. drill pipe—19.5 lb/ft is stripped into an influx in a 12-1/4 in. hole, determine the height, ft, gained:

DATA: Drill pipe capacity = 0.01776 bbl/ft
Drill pipe displacement = 0.00755 bbl/ft
Length drill pipe stripped = 300 ft
Annular capacity = 0.1215 bbl/ft

Solution: $$\text{Height, ft} = \frac{300(0.01776 + 0.00755)}{0.1215}$$

$$\text{Height} = 62.5\ \text{ft}$$

Casing pressure increase from stripping into influx

$$\text{psi} = \begin{pmatrix}\text{gain in} \\ \text{height, ft}\end{pmatrix} \times \begin{pmatrix}\text{gradient of} & - & \text{gradient of} \\ \text{mud, psi/ft} & & \text{influx, psi/ft}\end{pmatrix}$$

Example: Gain in height = 62.5 ft
Gradient of mud (12.5 ppg × 0.052) = 0.65 psi/ft
Gradient of influx = 0.12 psi/ft

$$\text{psi} = 62.5\,\text{ft} \times (0.65 - 0.12)$$
$$\text{psi} = 33\,\text{psi}$$

Volume of mud that must be bled to maintain constant bottomhole pressure with a gas bubble rising

With pipe in the hole:

$$\text{Vmud} = \frac{\text{Dp} \times \text{Ca}}{\text{gradient of mud, psi/ft}}$$

where Vmud = volume of mud, bbl, that must be bled to maintain constant bottomhole pressure with a gas bubble rising.
Dp = incremental pressure steps that the casing pressure will be allowed to increase.
Ca = annular capacity, bbl/ft

Example: Casing pressure increase per step = 100 psi
Gradient of mud (13.5 ppg × 0.052) = 0.70 psi/ft
Annular capacity = 0.1215 bbl/ft
(Dh = 12-1/4 in.; Dp = 5.0 in.)

$$\text{Vmud} = \frac{100\,\text{psi} \times 0.1215\,\text{bbl/ft}}{0.702\,\text{psi/ft}}$$

$$\text{Vmud} = 17.3\,\text{bbl}$$

With no pipe in hole:

$$\text{Vmud} = \frac{\text{Dp} \times \text{Ch}}{\text{Gradient of mud, psi/ft}}$$

where Ch = hole size or casing ID, in.

Example: Casing pressure increase per step = 100 psi
Gradient of mud (13.5 ppg × 0.052) = 0.702 psi/ft
Hole capacity (12-1/4 in.) = 0.1458 bbl/ft

$$\text{Vmud} = \frac{100\text{ psi} \times 0.1458\text{ bbl/ft}}{0.702\text{ psi/ft}}$$

Vmud = 20.77 bbl

Maximum Allowable Surface Pressure (MASP) governed by the formation

$$\text{MASP, psi} = \begin{pmatrix}\text{maximum} & & \text{mud wt,} \\ \text{allowable} & - & \text{in use,} \\ \text{mud wt, ppg} & & \text{ppg}\end{pmatrix} 0.052 \times \begin{matrix}\text{casing} \\ \text{shoe} \\ \text{TVD, ft}\end{matrix}$$

Example: Maximum allowable mud weight = 15.0 ppg
(from leak-off test data)
Mud weight = 12.0 ppg
Casing seat TVD = 8000 ft

MASP, psi = (15.0 − 12.0) × 0.052 × 8000
MASP = 1248 psi

Maximum Allowable Surface Pressure (MASP) governed by casing burst pressure

$$\text{MASP} = \begin{pmatrix}\text{casing} & & \\ \text{burst} & \times & \text{safety} \\ \text{pressure,} & & \text{factor} \\ \text{psi} & & \end{pmatrix} - \begin{pmatrix}\text{mud wt} & & \text{mud wt} \\ \text{in use,} & - & \text{outside} \\ \text{ppg} & & \text{casing,} \\ & & \text{ppg}\end{pmatrix} \times 0.052 \times \begin{pmatrix}\text{casing} \\ \text{shoe} \\ \text{TVD, ft}\end{pmatrix}$$

Example: Casing—10-3/4 in.—51 lb/ft N-80
Casing burst pressure = 6070 psi
Casing setting depth = 8000 ft
Mud weight behind casing = 9.4 ppg
Mud weight in use = 12.0 ppg
Casing safety factor = 80%

MASP = (6070 × 80%) − [(12.0 − 9.4) × 0.052 × 8000]
MASP = 4856 × (2.6 × 0.052 × 8000)
MASP = 3774 psi

Subsea Considerations

Casing pressure decrease when bringing well on choke

When bringing the well on choke with a subsea stack, the casing pressure (annulus pressure) must be allowed to decrease by the amount of choke line pressure loss (friction pressure):

$$\text{Reduced casing pressure, psi} = \begin{pmatrix}\text{shut-in} \\ \text{casing} \\ \text{pressure, psi}\end{pmatrix} - \begin{pmatrix}\text{choke line} \\ \text{pressure loss, psi}\end{pmatrix}$$

Example: Shut-in casing (annulus) pressure (SICP) = 800 psi
Choke line pressure loss (CLPL) = 300 psi

$$\text{Reduced casing pressure, psi} = 800\text{ psi} - 300\text{ psi}$$

$$\text{Reduced casing pressure} = 500\text{ psi}$$

Pressure chart for bringing well on choke

Pressure/stroke relationship is not linear. When bringing the well on choke, to maintain a constant bottomhole pressure, the following chart should be used:

Pressure Chart

	Strokes	Pressure
Line 1: Reset stroke counter to "0" =	0	
Line 2: 1/2 stroke rate = 50 × .5 =	25	
Line 3: 3/4 stroke rate = 50 × .75 =	38	
Line 4: 7/8 stroke rate = 50 × .875 =	44	
Line 5: Kill rate speed =	50	

Strokes side:
Example: kill rate speed = 50 spm

Pressure side:
Example: Shut-in casing pressure (SICP) = 800 psi
Choke line pressure loss (CLPL) = 300 psi

Divide choke line pressure loss (CLPL) by 4, because there are 4 steps on the chart:

$$\text{psi/line} = \frac{(\text{CLPL})\ 300\ \text{psi}}{4} = 75\ \text{psi}$$

Pressure Chart

	Strokes	Pressure
Line 1: Shut-in casing pressure, psi =		800
Line 2: Subtract 75 psi from Line 1 =		725
Line 3: Subtract 75 psi from Line 2 =		650
Line 4: Subtract 75 psi from Line 3 =		575
Line 5: Reduced casing pressure =		500

Maximum allowable mud weight, ppg, subsea stack as derived from leak-off test data

$$\begin{array}{l}\text{Maximum}\\ \text{allowable}\\ \text{mud weight,}\\ \text{ppg}\end{array} = \left(\begin{array}{l}\text{leak-off}\\ \text{test}\\ \text{pressure,}\\ \text{psi}\end{array}\right) \div 0.052 \div \left(\begin{array}{l}\text{TVD, ft}\\ \text{RKB to}\\ \text{casing shoe}\end{array}\right) + \left(\begin{array}{l}\text{mud wt}\\ \text{in use}\\ \text{ppg}\end{array}\right)$$

Example: Leak-off test pressure = 800 psi
TVD from rotary bushing to casing shoe = 4000 ft
Mud weight in use = 9.2 ppg

Maximum allowable mud weight, ppg = 800 ÷ 0.052 ÷ 4000 + 9.2

Maximum allowable mud weight = 13.0 ppg

Maximum allowable shut-in casing (annulus) pressure

$$\text{MASICP} = \left(\begin{array}{l}\text{maximum}\\ \text{allowable}\\ \text{mud wt, ppg}\end{array} - \begin{array}{l}\text{mud wt}\\ \text{in use,}\\ \text{ppg}\end{array}\right) \times 0.052 \times \left(\begin{array}{l}\text{TVD, ft}\\ \text{RKB to}\\ \text{casing shoe}\end{array}\right)$$

Example: Maximum allowable mud weight = 13.3 ppg
Mud weight in use = 11.5 ppg
TVD from rotary kelly bushing to casing shoe = 4000 ft

MASICP = (13.3 ppg − 11.5 ppg) × 0.052 × 4000 ft
MASICP = 374

Casing burst pressure—subsea stack

Step 1

Determine the internal yield pressure of the casing from the "Dimensions and Strengths" section of cement company's service handbook.

Step 2

Correct internal yield pressure for safety factor. Some operators use 80%; some use 75%, and others use 70%:

$$\text{Correct internal yield pressure, psi} = \left(\begin{array}{l}\text{internal yield}\\ \text{pressure, psi}\end{array}\right) \times \text{SF}$$

Step 3

Determine the hydrostatic pressure of the mud in use:

NOTE: The depth is from the rotary kelly bushing (RKB) to the mud line and includes the air gap plus the depth of seawater.

$$\text{HP, psi} = \left(\begin{array}{l}\text{mud weight}\\ \text{in use, ppg}\end{array}\right) \times 0.052 \times \left(\begin{array}{l}\text{TVD, ft from}\\ \text{RKB to mud line}\end{array}\right)$$

Step 4

Determine the hydrostatic pressure exerted by the seawater:

HPsw = seawater weight, ppg × 0.052 × depth of seawater, ft

Step 5

Determine casing burst pressure (CBP):

$$\text{CBP} \times \left(\begin{array}{l}\text{corrected}\\ \text{internal}\\ \text{yield pressure,}\\ \text{psi}\end{array}\right) - \left(\begin{array}{lcl}\text{HP of} & & \text{HP of}\\ \text{mud in} & + & \text{seawater,}\\ \text{use, psi} & & \text{psi}\end{array}\right)$$

Example: Determine the casing burst pressure, subsea stack, using the following data:

DATA: Mud weight = 10.0 ppg
Weight of seawater = 8.7 ppg
Air gap = 50 ft
Water depth = 1500 ft
Correction (safety) factor = 80%

Step 1

Determine the internal yield pressure of the casing from the "Dimension and Strengths" section of a cement company handbook:

9-5/8″ casing — C-75, 53.5 lb/ft

Internal yield pressure = 7430 psi

Step 2

Correct internal yield pressure for safety factor:

$$\text{Corrected internal yield pressure} = 7430\text{ psi} \times 0.80$$

$$\text{Corrected internal yield pressure} = 5944\text{ psi}$$

Step 3

Determine the hydrostatic pressure exerted by the mud in use:

$$\text{HP of mud, psi} = 10.0\text{ ppg} \times 0.052 \times (50\text{ ft} + 1500\text{ ft})$$
$$\text{HP of mud} = 806\text{ psi}$$

Step 4

Determine the hydrostatic pressure exerted by the seawater:

$$\text{HPsw} = 8.7\text{ ppg} \times 0.052 \times 1500\text{ ft}$$
$$\text{HPsw} = 679\text{ psi}$$

Step 5

Determine the casing burst pressure:

$$\text{Casing burst pressure, psi} = 5944\text{ psi} - 806\text{ psi} + 679\text{ psi}$$

Casing burst pressure $= 5817$ psi

Calculate Choke Line Pressure Loss (CLPL), psi

$$\text{CLPL} = \frac{0.000061 \times \text{MW, ppg} \times \text{length, ft} \times \text{GPM}^{1.86}}{\text{choke line ID, in.}^{4.86}}$$

Example: Determine the choke line pressure loss (CLPL), psi, using the following data:

DATA: Mud weight = 14.0 ppg
Choke line length = 2000 ft
Circulation rate = 225 gpm
Choke line ID = 2.5 in.

$$\text{CLPL} = \frac{0.000061 \times 14.0\,\text{ppg} \times 2000\,\text{ft} \times 225^{1.86}}{2.5^{4.86}}$$

$$\text{CLPL} = \frac{40{,}508.611}{85.899066}$$

$$\text{CLPL} = 471.58\,\text{psi}$$

Velocity, ft/min, through the choke line

$$\text{V, ft/min} = \frac{24.5 \times \text{gpm}}{\text{ID, in.}^2}$$

Example: Determine the velocity, ft/min, through the choke line using the following data:

Data: Circulation rate = 225 gpm
Choke line ID = 2.5 in.

$$\text{V, ft/min} = \frac{24.5 \times 225}{2.5^2}$$

$$\text{V} = 882\,\text{ft/min}$$

Adjusting choke line pressure loss for a higher mud weight

$$\text{New CLPL} = \frac{\text{higher mud wt, ppg} \times \text{CLPL}}{\text{old mud weight, ppg}}$$

Example: Use the following data to determine the new estimated choke line pressure loss:

Data: Old mud weight = 13.5 ppg
New mud weight = 15.0 ppg
Old choke line pressure loss = 300 psi

$$\text{New CLPL} = \frac{15.0\text{ ppg} \times 300\text{ psi}}{13.5\text{ ppg}}$$

New CLPL = 333.33 psi

Minimum conductor casing setting depth

Example: Using the following data, determine the minimum setting depth of the conductor casing below the seabed:

Data: Water depth = 450 ft
Gradient of seawater = 0.445 psi/ft
Air gap = 60 ft
Formation fracture gradient = 0.68 psi/ft
Maximum mud weight (to be used while drilling this interval) = 9.0 ppg

Step 1

Determine formation fracture pressure:

psi = (450 × 0.445) + (0.68 × "y")
psi = 200.25 + 0.68 "y"

Step 2

Determine hydrostatic pressure of mud column:

psi = 90 ppg × 0.052 × (60 + 450 + "y")
psi = [9.0 × 0.052 × (60 + 450)] + (9.0 × 0.052 × "y")
psi = 238.68 + 0.468"y"

Step 3

Minimum conductor casing setting depth:

$$
\begin{aligned}
200.25 + 0.68\text{“y”} &= 238.68 + 0.468\text{“y”} \\
0.68\text{“y”} - 0.468\text{“y”} &= 238.68 - 200.25 \\
0.212\text{“y”} &= 38.43 \\
\text{“y”} &= \frac{38.43}{0.212} \\
\text{“y”} &= 181.3\,\text{ft}
\end{aligned}
$$

Therefore, the minimum conductor casing setting depth is 181.3 ft below the seabed.

Maximum mud weight with returns back to rig floor

Example: Using the following data, determine the maximum mud weight that can be used with returns back to the rig floor:

Data: Depths

Air gap	= 75 ft
Water depth	= 600 ft
Conductor casing set at	= 1225 ft RKB
Seawater gradient	= 0.445 psi/ft
Formation fracture gradient	= 0.58 psi/ft

Step 1

Determine total pressure at casing seat:

$$
\begin{aligned}
\text{psi} &= [0.58(1225 - 600 - 75)] + (0.445 \times 600) \\
\text{psi} &= 319 + 267 \\
\text{psi} &= 586
\end{aligned}
$$

Step 2

Determine maximum mud weight:

$$
\begin{aligned}
\text{Max mud wt} &= 586\,\text{psi} \div 0.052 \div 1225\,\text{ft} \\
\text{Max mud wt} &= 9.2\,\text{ppg}
\end{aligned}
$$

Reduction in bottomhole pressure if riser is disconnected

Example: Use the following data and determine the reduction in bottomhole pressure if the riser is disconnected:

Date:	Air gap	= 75 ft
	Water depth	= 700 ft
	Seawater gradient	= 0.445 psi/ft
	Well depth	= 2020 ft RKB
	Mud weight	= 9.0 ppg

Step 1

Determine bottomhole pressure:

BHP = 9.0 ppg × 0.052 × 2020 ft
BHP = 945.4 psi

Step 2

Determine bottomhole pressure with riser disconnected:

BHP = (0.445 × 700) + [9.0 × 0.052 × (2020 − 700 − 75)]
BHP = 311.5 + 582.7
BHP = 894.2 psi

Step 3

Determine bottomhole pressure reduction:

BHP reduction = 945.4 psi − 894.2 psi
BHP reduction = 51.2 psi

Bottomhole pressure when circulating out a kick

Example: Use the following data and determine the bottomhole pressure when circulating out a kick:

Data:	Total depth—RKB	= 13,500 ft
	Height of gas kick in casing	= 1200 ft
	Gas gradient	= 0.12 psi/ft
	Original mud weight	= 12.0 ppg
	Kill weight mud	= 12.7 ppg
	Pressure loss in annulus	= 75 psi
	Choke line pressure loss	= 220 psi

Air gap	= 75 ft
Water depth	= 1500 ft
Annulus (casing) pressure	= 631 psi
Original mud in casing below gas	= 5500 ft

Step 1

Hydrostatic pressure in choke line:

psi = 12.0 ppg × 0.052 × (1500 + 75)
psi = 982.8

Step 2

Hydrostatic pressure exerted by gas influx:

psi = 0.12 psi/ft × 1200 ft
psi = 144

Step 3

Hydrostatic pressure of original mud below gas influx:

psi = 12.0 ppg × 0.052 × 5500 ft
psi = 3432

Step 4

Hydrostatic pressure of kill weight mud:

psi = 12.7 ppg × 0.052 × (13,500 − 5500 − 1200 − 1500 − 75)
psi = 12.7 ppg × 0.052 × 5225
psi = 3450.59

Step 5

Bottomhole pressure while circulating out a kick:

Pressure in choke line	= 982.8 psi
Pressure of gas influx	= 144 psi
Original mud below gas in casing	= 3432 psi
Kill weight mud	= 3450.59 psi
Annulus (casing) pressure	= 630 psi
Choke line pressure loss	= 200 psi
Annular pressure loss	= 75 psi
Bottomhole pressure while circulating out a kick	= 8914.4 psi

Workover Operations

NOTE: The following procedures and calculations are more commonly used in workover operations, but at times they are used in drilling operations.

Bullheading

Bullheading is a term used to describe killing the well by forcing formation fluids back into the formation. This involves pumping kill weight fluid down the tubing and, in some cases, down the casing.

The bullheading method of killing a well is primarily used in the following situations:

a) Tubing in the well with a packer set. No communication exists between tubing and annulus.
b) Tubing in the well, influx in the annulus, and for some reason, cannot circulate through the tubing.
c) No tubing in the well. Influx in the casing. Bullheading is simplest, fastest, and safest method to use to kill the well.

NOTE: Tubing could be well off bottom also.

d) In drilling operations, bullheading has been used successfully in areas where hydrogen sulfide is a possibility.

Example calculations involved in bullheading operations:

Using the information given below, calculations will be performed to kill the well by bullheading. The example calculations will pertain to "a" above:

DATA:	Depth of perforations	= 6480 ft
	Fracture gradient	= 0.862 psi/ft
	Formation pressure gradient	= 0.401 psi/ft
	Tubing hydrostatic pressure (THP)	= 326 psi
	Shut-in tubing pressure	= 2000 psi
	Tubing	= 2-7/8 in. – 6.5 lb/ft
	Tubing capacity	= 0.00579 bbl/ft
	Tubing internal yield pressure	= 7260 psi
	Kill fluid density	= 8.4 ppg

NOTE: Determine the best pump rate to use. The pump rate must exceed the rate of gas bubble migration up the tubing. The rate of gas bubble migration, ft/hr, in a shut-in well can be determined by the following formula:

$$\text{Rate of gas migration, ft/hr} = \begin{pmatrix}\text{increase in pressure} \\ \text{per/hr, psi}\end{pmatrix} \div \begin{pmatrix}\text{completion fluid} \\ \text{gradient, psi/ft}\end{pmatrix}$$

Solution:

Calculate the maximum allowable tubing (surface) pressure (MATP) for formation fracture:

a) MATP, initial, with influx in the tubing:

$$\text{MATP, initial} = \begin{pmatrix}\text{fracture} & & \text{depth of} \\ \text{gradient,} & \times & \text{perforations,} \\ \text{psi/ft} & & \text{ft}\end{pmatrix} - \begin{pmatrix}\text{tubing} \\ \text{hydrostatic} \\ \text{pressure, psi}\end{pmatrix}$$

MATP, initial = (0.862 psi/ft × 6480 ft) − 326 psi

MATP, initial = 5586 psi − 326 psi

MATP, initial = 5260 psi

b) MATP, final, with kill fluid in tubing:

$$\text{MATP, final} = \begin{pmatrix}\text{fracture} & & \text{depth of} \\ \text{gradient,} & \times & \text{perforations,} \\ \text{psi/ft} & & \text{ft}\end{pmatrix} - \begin{pmatrix}\text{tubing} \\ \text{hydrostatic} \\ \text{pressure, psi}\end{pmatrix}$$

MATP, final = (0.862 × 6480) − (8.4 × 0.052 × 6480)

MATP, final = 5586 psi − 2830 psi

MATP, final = 2756 psi

Determine tubing capacity:

Tubing capacity, bbl = tubing length, ft × tubing capacity, bbl/ft

Tubing capacity, bbl = 6480 ft × 0.00579 bbl/ft

Tubing capacity = 37.5 bbl

Plot these values as shown below:

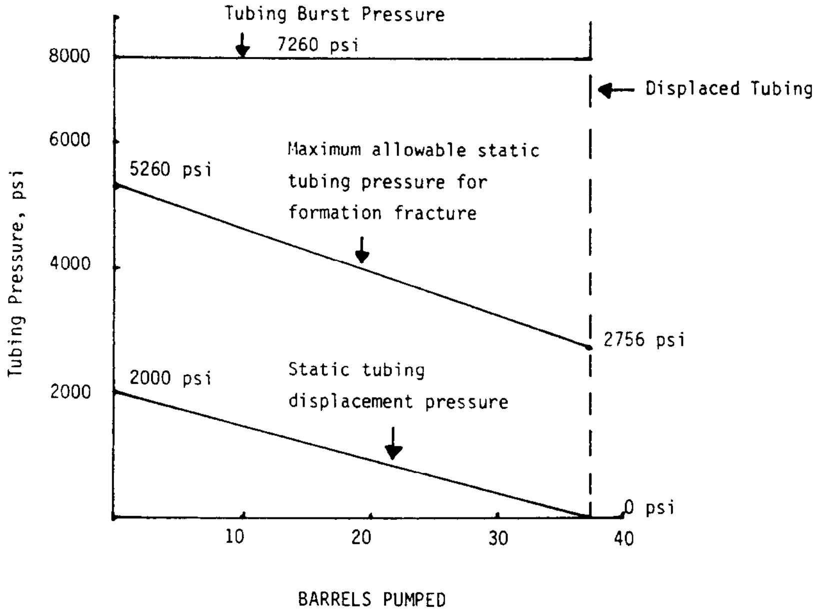

Figure 4-3. Tubing pressure profile.

Lubricate and bleed

The lubricate and bleed method involves alternately pumping a kill fluid into the tubing (or into the casing if there is no tubing in the well), allowing the kill fluid to fall, then bleeding off a volume of gas until kill fluid reaches the choke. As each volume of kill fluid is pumped into the tubing, the SITP should decrease by a calculated value until the well is eventually killed.

This method is often used for two reasons: 1) shut-in pressures approach the rated working pressure of the wellhead or tubing and dynamic pumping pressure may exceed the limits, as in the case of bullheading, and 2) either to completely kill the well or lower the SITP to a value where other kill methods can be safely employed without exceeding rated limits.

This method can also be applied when the wellbore or perforations are plugged, rendering bullheading useless. In this case, the well can be killed without the use of tubing or snubbing small diameter tubing.

Users should be aware that the lubricate and bleed method is often a very time consuming process, whereas another method may kill the well more quickly. The following is an example of a typical lubricate and bleed kill procedure.

Example: A workover is planned for a well where the SITP approaches the working pressure of the wellhead equipment. To minimize the possibility of equipment failure, the lubricate and bleed method will be used to reduce the SITP to a level at which bullheading can be safely conducted. The data below will be used to decribe this procedure:

TVD	= 6500 ft
Depth of perforations	= 6450 ft
SITP	= 2830 psi
Tubing	= 2-7/8 in. − 6.5 lb/ft-N-80
Tubing capacity	= 0.00579 bbl/ft
	172.76 ft/bbl
Tubing internal yield	= 10,570 psi
Wellhead working pressure	= 3000 psi
Kill fluid density	9.0 ppg

Calculations:

Calculate the expected pressure reduction for each barrel of kill fluid pumped:

psi/bbl = tubing capacity, ft/bbl × 0.052 × kill weight fluid, ppg
psi/bbl = 172.76 ft/bbl × 0.052 × 9.0 ppg
psi/bbl = 80.85

For each barrel pumped, the SITP will be reduced by 80.85 psi.

Calculate tubing capacity, bbl, to the perforations:

bbl = tubing capacity, bbl/ft × depth to perforations, ft
bbl = 0.00579 bbl/ft × 6450 ft
bbl = 37.3 bbl

Procedure:

1. Rig up all surface equipment including pumps and gas flare lines.
2. Record SITP and SICP.
3. Open the choke to allow gas to escape from the well and momentarily reduce the SITP.
4. Close the choke and pump in 9.0 ppg brine until the tubing pressure reaches 2830 psi.

5. Wait for a period of time to allow the brine to fall in the tubing. This period will range from 1/4 to 1 hour depending on gas density, pressure, and tubing size.
6. Open the choke and bleed gas until 9.0 ppg brine begins to escape.
7. Close the choke and pump in 9.0 ppg brine water.
8. Continue the process until a low level, safe working pressure is attained.

A certain amount of time is required for the kill fluid to fall down the tubing after the pumping stops. The actual waiting time is needed not to allow fluid to fall, but rather, for gas to migrate up through the kill fluid. Gas migrates at rates of 1000 to 2000 ft/hr. Therefore considerable time is required for fluid to fall or migrate to 6500 ft. Therefore, after pumping, it is important to wait several minutes before bleeding gas to prevent bleeding off kill fluid through the choke.

Controlling Gas Migration

Gas migration can occur when a well is shut in on a gas kick. It is indicated by a uniform increase in both the SIDPP and SICP. If the influx is allowed to migrate without expanding, pressures will increase everywhere in the wellbore. If it is ignored it can cause formation damage and mud losses. The worst-case scenario would be an underground blowout.

Gas migration can be controlled using two methods:

- Drill Pipe pressure method
- Volumetric method

Drill pipe pressure method

English units

This is a constant bottom hole pressure method of well control, and it is the simplest method. In order to use this method, the bit must be on bottom with no float in the string.

Procedure:

1. Allow the SIDPP to increase by a safety margin: 50–100 psi. This is the lower limit. The SIDPP must not be allowed to decrease below this level.
2. Next, allow the drill pipe pressure to further increase by another 50–100 psi. This is the upper limit.

3. Open the choke and bleed fluid out of the well until the drill pipe pressure drops to the lower limit.
4. Repeat steps 2 and 3 until circulation is possible or the gas migrates to the top of the well.

Metric units

Procedure:

1. Allow the SIDPP to increase by a safety margin: 350–1400 kPa. This is the lower limit.
2. Next, allow the drill pipe pressure to further increase by another 350–1400 kPa. This is the upper limit.
3. Open the choke, and bleed mud out of the well until the drill pipe pressure drops to the lower limit value.
4. Repeat steps 2 and 3 until circulation is possible or the gas migrates to the top of the well.

Volumetric method of gas migration

English units

Procedure:

1. Select a safety margin, Ps, and a working pressure, Pw. Recommended: Ps = 100 psi; Pw = 100 psi.
2. Calculate the hydrostatic pressure per barrel of mud, Hp/bbl:

   Hp/bbl = mud gradient, psi/ft ÷ annular capacity, bbl/ft

3. Calculate the volume to bleed each cycle:

   Volume, bbl to bleed each cycle = Pw ÷ Hp/bbl

4. Allow the shut in casing pressure to increase by Ps without bleeding from the well.
5. Allow the shut in casing pressure to further increase by Pw without bleeding from the well.
6. Maintain casing pressure constant by bleeding small volumes of mud from the well until total mud bled equals the correct volume to bleed per cycle.
7. Repeat steps 5 and 6 until another procedure is implemented or all gas is at the surface.

Metric units

Procedure:

1. Select a safety margin, Ps, and a working pressure, Pw. Recommended: Ps = 700 kPa; Pw = 700 kPa.
2. Calculate the hydrostatic pressure increase per m^3 of mud.

   Hp/m^3 = mud gradient, kPa/m ÷ annular capacity, m^3/m

3. Calculate the volume to bleed per cycle:

   Volume, m = Pw ÷ Hp/m^3

4. Allow shut in casing pressure to increase by Ps without bleeding mud from the well.
5. Allow the shut in casing pressure to further increase by Pw without bleeding mud from the well.
6. Maintain constant casing pressure by bleeding small volumes of mud from the well until total mud bled from the well equals correct volume to bleed per cycle.
7. Repeat steps 5 and 6 until another procedure is implemented or all gas is at the surface.

Gas Lubrication

Gas lubrication is the process of removing gas from beneath the BOP stack while maintaining constant bottom hole pressure. Lubrication is best suited for surface stacks, but the dynamic gas lubrication procedure can be used to vent gas from beneath a subsea stack.

Lubrication can be used to reduce pressures or to remove gas from beneath a surface stack prior to stripping or after implementing the Volumetric Procedure for controlling gas migration. The volume of mud lubricated into the well must be accurately measured.

Gas lubrication—volume method

English units

Procedure:

1. Select a range of working pressure, Pw. Recommended Pw = 100–200 psi.

2. Calculate the hydrostatic pressure increase in the upper annulus per bbl of lube mud:

   Hp/bbl = mud gradient ÷ annular capacity

3. Pump lube mud through the kill line to increase the casing pressure by the working pressure range, Pw.
4. Measure the trip tank and calculate the hydrostatic pressure increase of the mud lubricated for this cycle.
5. Wait 10 to 30 minutes for the mud to lubricate through the gas.
6. Bleed "dry" gas from the choke to reduce the casing pressure by the hydrostatic pressure increase plus the working pressure range.
7. Repeat steps 3 through 6 until lubrication is complete.

Metric units

Procedure:

1. Select a working pressure range, Pw. Recommended Pw = 700–1400 kPa.
2. Calculate the hydrostatic pressure increase in the upper annulus per m^3 of lube mud:

   Hp/m^3 = mud gradient ÷ annular capacity

3. Pump lube mud through kill line to increase casing pressure by working pressure range, Pw.
4. Measure the trip tank and calculate the hydrostatic pressure increase of the mud lubricated for this cycle.
5. Wait 10 to 30 minutes for the mud to "lubricate" through the gas.
6. Bleed "dry" gas from the choke to reduce the casing pressure by the hydrostatic pressure increase plus the working pressure range.
7. Repeat steps 3 through 6 until lubrication is complete.

Gas lubrication—pressure method

Because of its simplicity, the pressure method is the preferred method of gas lubrication. However, it is only applicable when the mud weight being lubricated is sufficient to kill the well, as in the case of a swabbed influx. The pressure method is also the only accurate method whenever the formation is "taking" fluid, as is the case for most completed wellbores and whenever seepage loss is occurring.

The pressure method of gas lubrication utilizes the following formula:

$$P_3 = P_1^2 \div P_2$$

Where: P_1 = original shut in pressure
P_2 = pressure increase due to pumping lubricating fluid into the wellbore (increase is due to compression)
P_3 = pressure to bleed down after adding the hydrostatic of the lubricating fluid

Procedure:

1. Select a working pressure range, Pw. Recommended Pw = 50–100 psi.
2. Pump lubricating fluid through the kill line to increase the casing pressure by the working pressure, Pw.
3. Allow the pressure to stabilize. The pressure may drop by a substantial amount.
4. Calculate the pressure to bleed down to by using the formula above.
5. Repeat steps 2 through 4 until all the gas is lubricated out of the well.

Annular Stripping Procedures

Strip and bleed procedure

Application: Appropriate when stripping 30 stands or less or when gas migration is not a problem.

Procedure:

1. Strip the first stand with the choke closed to allow the casing pressure to increase. NOTE: Do not allow the casing pressure to rise above the maximum allowable surface pressure derived from the most recent leak-off test.
2. Bleed enough volume to allow the casing pressure to decrease to a safety margin of 100–200 psi above the original shut in casing pressure.
3. Continue to strip pipe with the choke closed unless the casing pressure approaches the maximum allowable surface pressure. If the casing pressure approaches the maximum allowable surface pressure, then bleed volume as the pipe is being stripped to minimize the casing pressure.
4. Once the bit is back on bottom, utilize the Driller's Method to circulate the influx out of the well.

Combined stripping/volumetric procedure

Application: Procedure to use when gas migration is a factor. Gas is allowed to expand while stripping. Mud is bled into a trip tank and then closed end displacement into a smaller stripping tank. Trip tank measures gas expansion similar to volumetric method. Pressure is stepped up as in the volumetric method.

Worksheet:

1. Select a working pressure, Pw. Recommended Pw = 50–100 psi.
2. Calculate the hydrostatic pressure:

   Hp/bbl = pressure gradient, psi/ft ÷ upper annular capacity, bbl/ft

3. Calculate influx length in the open hole:

   L_1 = influx volume, bbl ÷ open hole capacity, bbl/ft

4. Calculate influx length after the BHA has penetrated the influx:

   L_2 = influx volume, bbl ÷ annular capacity (drill collars/open hole), bbl/ft

5. Calculate the pressure increase due to bubble penetration, Ps:

   Ps = $(L_2 - L_1)$ × (gradient of mud, psi/ft − 0.1 psi/ft)

6. Calculate the Pchoke values:

   $Pchoke_1$ = SICP + Pw + Ps
   $Pchoke_2$ = $Pchoke_1$ + Pw
   $Pchoke_3$ = $Pchoke_2$ + Pw

7. Calculate the incremental volume (Vm) of hydrostatic equal to Pw in the upper annulus:

   Vm = Pw ÷ Hp/bbl

Procedure:

1. Strip in the first stand with the choke closed until the casing pressure reaches $Pchoke_1$.
2. As the driller strips the pipe, the choke operator should open the choke and bleed mud, being careful to hold the casing pressure at $Pchoke_1$.
3. With the stand down, close the choke. Bleed the closed end displacement volume from the trip tank to the stripping tank.
4. Repeat steps 2 and 3 above, stripping stands until Vm accumulates in the trip tank.
5. Allow casing pressure to climb to the next Pchoke level.
6. Continue stripping, repeating steps 2 through 4 at the new Pchoke value.
7. When the bit is on the bottom, kill the well with the Driller's Method.

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CHAPTER FIVE

ENGINEERING CALCULATIONS

Bit Nozzle Selection—Optimized Hydraulics

These series of formulas will determine the correct jet sizes when optimizing for jet impact or hydraulic horsepower and optimum flow rate for two or three nozzles.

1. Nozzle area, sq in.:

$$\text{Nozzle area, sq in.} = \frac{N_1^2 + N_2^2 + N_3^2}{1303.8}$$

2. Bit nozzle pressure loss, psi (Pb):

$$Pb = \frac{\text{gpm}^2 \times \text{MW, ppg}}{10{,}858 \times \text{nozzle area, sq in.}^2}$$

3. Total pressure losses except bit nozzle pressure loss, psi (Pc):

$$Pc_1 \;\&\; Pc_2 = \begin{matrix}\text{circulating} \\ \text{pressure, psi}\end{matrix} - \begin{matrix}\text{bit nozzle} \\ \text{pressure Loss, psi}\end{matrix}$$

4. Determine slope of line M:

$$M = \frac{\log(Pc_1 \div Pc_2)}{\log(Q_1 \div Q_2)}$$

5. Optimum pressure losses (Popt)

a) For impact force:

$$\text{Popt} = \frac{2}{M + 2} \times \text{Pmax}$$

b) For hydraulic horsepower:

$$\text{Popt} = \frac{1}{M+1} \times \text{Pmax}$$

6. For optimum flow rate (Qopt):

a) For impact force:

$$\text{Qopt, gpm} = \left(\frac{\text{Popt}}{\text{Pmax}}\right)^{1\div M} \times \text{Q1}$$

b) For hydraulic horsepower:

$$\text{Qopt, gpm} = \left(\frac{\text{Popt}}{\text{Pmax}}\right)^{1\div M} \times \text{Q1}$$

7. To determine pressure at the bit (Pb):

$$\text{Pb} = \text{Pmax} - \text{Popt}$$

8. To determine nozzle area, sq in.:

$$\text{Nozzle area, sq in.} = \sqrt{\frac{\text{Qopt}^2 \times \text{MW, ppg}}{10{,}858 \times \text{Pmax}}}$$

9. To determine nozzles, 32nd in. for three nozzles:

$$\text{Nozzles} = \sqrt{\frac{\text{nozzle area, sq in.}}{3 \times 0.7854}} \times 32$$

10. To determine nozzles, 32nd in. for two nozzles:

$$\text{Nozzles} = \sqrt{\frac{\text{nozzle area, sq in.}}{2 \times 0.7854}} \times 32$$

Example: Optimize bit hydraulics on a well with the following:

Select the proper jet sizes for impact force and hydraulic horsepower for two jets and three jets:

DATA:	Mud weight	= 13.0 ppg
	Jet sizes	= 17-17-17
	Maximum surface pressure	= 3000 psi
	Pump pressure 1	= 3000 psi
	Pump rate 1	= 420 gpm
	Pump pressure 2	= 1300 psi
	Pump rate 2	= 275 gpm

1. Nozzle area, sq in.:

$$\text{Nozzle area, sq in.} = \frac{17^2 + 17^2 + 17^2}{1303.8}$$

Nozzle area, sq in. = 0.664979

2. Bit nozzle pressure loss, psi (Pb):

$$Pb_1 = \frac{420^2 \times 13.0}{10{,}858 \times 0.664979^2}$$

$Pb_1 = 478\,psi$

$$Pb_2 = \frac{275^2 \times 13.0}{10{,}858 \times 0.664979^2}$$

$Pb_2 = 205\,psi$

3. Total pressure losses except bit nozzle pressure loss (Pc), psi:

$Pc_1 = 3000\,psi - 478\,psi$
$Pc_1 = 2522\,psi$

$Pc_2 = 1300\,psi - 205\,psi$
$Pc_2 = 1095\,psi$

4. Determine slope of line (M):

$$M = \frac{\log(2522 \div 1095)}{\log(420 \div 275)}$$

$$M = \frac{0.3623309}{0.1839166}$$

$M = 1.97$

5. Determine optimum pressure losses, psi (Popt):

a) For impact force:

$$Popt = \frac{2}{1.97 + 2} \times 3000$$

$Popt = 1511\,psi$

b) For hydraulic horsepower:

$$Popt = \frac{1}{1.97 + 1} \times 3000$$

$Popt = 1010\,psi$

6. Determine optimum flow rate (Qopt):

a) For impact force:

$$\text{Qopt, gpm} = \left(\frac{1511}{3000}\right)^{1 \div 1.97} \times 420$$

$$\text{Qopt} = 297\,\text{gpm}$$

b) For hydraulic horsepower:

$$\text{Qopt, gpm} = \left(\frac{1010}{3000}\right)^{1 \div 1.97} \times 420$$

$$\text{Qopt} = 242\,\text{gpm}$$

7. Determine pressure losses at the bit (Pb):

a) For impact force:

$$\text{Pb} = 3000\,\text{psi} - 1511\,\text{psi}$$
$$\text{Pb} = 1489\,\text{psi}$$

b) For hydraulic horsepower:

$$\text{Pb} = 3000\,\text{psi} - 1010\,\text{psi}$$
$$\text{Pb} = 1990\,\text{psi}$$

8. Determine nozzle area, sq in.:

a) For impact force:

$$\text{Nozzle area, sq in.} = \sqrt{\frac{297^2 \times 13.0}{10{,}858 \times 1489}}$$

$$\text{Nozzle area, sq in.} = \sqrt{0.070927}$$

$$\text{Nozzle area} = 0.26632\,\text{sq in.}$$

b) For hydraulic horsepower:

$$\text{Nozzle area, sq in.} = \sqrt{\frac{242^2 \times 13.0}{10{,}858 \times 1990}}$$

$$\text{Nozzle area, sq in.} = \sqrt{0.03523}$$

$$\text{Nozzle area} = 0.1877\,\text{sq in.}$$

9. Determine nozzle size, 32nd in.:

a) For impact force:

$$\text{Nozzles} = \sqrt{\frac{0.26632}{3 \times 0.7854}} \times 32$$

Nozzles = 10.76

b) For hydraulic horsepower:

$$\text{Nozzles} = \sqrt{\frac{0.1877}{3 \times 0.7854}} \times 32$$

Nozzles = 9.03

NOTE: Usually the nozzle size will have a decimal fraction. The fraction times 3 will determine how many nozzles should be larger than that calculated.

a) For impact force:

$0.76 \times 3 = 2.28$ rounded to 2

so: 1 jet = 10/32nds
2 jets = 11/32nds

b) For hydraulic horsepower:

$0.03 \times 3 = 0.09$ rounded to 0

so: 3 jets = 9/32nd in.

10. Determine nozzles, 32nd in. for two nozzles:

a) For impact force:

$$\text{Nozzles} = \sqrt{\frac{0.26632}{2 \times 0.7854}} \times 32$$

Nozzles = 13.18 sq in.

b) For hydraulic horsepower:

$$\text{Nozzles} = \sqrt{\frac{0.1877}{2 \times 0.7854}} \times 32$$

Nozzles = 11.06 sq in.

Hydraulics Analysis

This sequence of calculations is designed to quickly and accurately analyze various parameters of existing bit hydraulics.

1. Annular velocity, ft/min (AV):

$$AV = \frac{24.5 \times Q}{Dh^2 - Dp^2}$$

2. Jet nozzle pressure loss, psi (Pb):

$$Pb = \frac{156.5 \times Q^2 \times MW}{\left[(N_1)^2 + (N_2)^2 + (N_3)^2\right]^2}$$

3. System hydraulic horsepower available (Sys HHP):

$$SysHHP = \frac{\text{surface, psi} \times Q}{1714}$$

4. Hydraulic horsepower at bit (HHPb):

$$HHPb = \frac{Q \times Pb}{1714}$$

5. Hydraulic horsepower per square inch of bit diameter:

$$HHPb/\text{sq in.} = \frac{HHPb \times 1.27}{\text{bit size}^2}$$

6. Percent pressure loss at bit (% psib):

$$\%\ psib = \frac{Pb}{\text{surface, psi}} \times 100$$

7. Jet velocity, ft/sec (Vn):

$$Vn = \frac{417.2 \times Q}{(N_1)^2 + (N_2)^2 + (N_3)^2}$$

8. Impact force, lb, at bit (IF):

$$IF = \frac{(MW)(Vn)(Q)}{1930}$$

9. Impact force per square inch of bit area (IF/sq in.):

$$IF/\text{sq in.} = \frac{IF \times 1.27}{\text{bit size}^2}$$

Nomenclature:

AV	= annular velocity, ft/min
Q	= circulation rate, gpm
Dh	= hole diameter, in.
Dp	= pipe or collar O.D., in.
MW	= mud weight, ppg
N_1; N_2; N_3	= jet nozzle sizes, 32nd in.
Pb	= bit nozzle pressure loss, psi
HHP	= hydraulic horsepower at bit
Vn	= jet velocity, ft/sec
IF	= impact force, lb
IF/sq in.	= impact force lb/sq in. of bit diameter

Example:	Mub weight	= 12.0 ppg
	Circulation rate	= 520 gpm
	Nozzle size 1	= 12–32nd/in.
	Nozzle size 2	= 12–32nd/in.
	Nozzle size 3	= 12–32nd/in.
	Hole size	= 12–1/4 in.
	Drill pipe OD	= 5.0 in.
	Surface pressure	= 3000 psi

1. Annular velocity, ft/min:

$$AV = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$AV = \frac{12{,}740}{125.0625}$$

$$AV = 102 \text{ ft/min}$$

2. Jet nozzle pressure loss:

$$Pb = \frac{156.5 \times 520^2 \times 12.0}{\left(12^2 + 12^2 + 12^2\right)^2}$$

$$Pb = 2721 \text{ psi}$$

3. System hydraulic horsepower available:

$$\text{Sys HHP} = \frac{3000 \times 520}{1714}$$

$$\text{Sys HHP} = 910$$

4. Hydraulic horsepower at bit:

$$\text{HHPb} = \frac{2721 \times 520}{1714}$$

$$\text{HHPb} = 826$$

5. Hydraulic horsepower per square inch of bit area:

$$\text{HHp/sq in.} = \frac{826 \times 1.27}{12.25^2}$$

$$\text{HHP/sq in.} = 6.99$$

6. Percent pressure loss at bit:

$$\%\ \text{psib} = \frac{2721}{3000} \times 100$$

$$\%\ \text{psib} = 90.7$$

7. Jet velocity, ft/sec:

$$\text{Vn} = \frac{417.2 \times 520}{12^2 + 12^2 + 12^2}$$

$$\text{Vn} = \frac{216{,}944}{432}$$

$$\text{Vn} = 502\ \text{ft/sec}$$

8. Impact force, lb:

$$\text{IF} = \frac{12.0 \times 502 \times 520}{1930}$$

$$\text{IF} = 1623\,\text{lb}$$

9. Impact force per square inch of bit area:

$$\text{IF/sq in.} = \frac{1623 \times 1.27}{12.25^2}$$

$$\text{IF/sq in.} = 13.7$$

Critical Annular Velocity and Critical Flow Rate

1. Determine n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300}$$

2. Determine K:

$$K = \frac{\theta 600}{1022^{n}}$$

3. Determine x:

$$x = \frac{81{,}600(Kp)(n)^{0.387}}{(Dh - Dp)^{n} MW}$$

4. Determine critical annular velocity:

$$AVc = (x)^{1 \div 2 - n}$$

5. Determine critical flow rate:

$$GPMc = \frac{AVc(Dh^{2} - Dp^{2})}{24.5}$$

Nomenclature:

n = dimensionless
K = dimensionless
x = dimensionless
θ600 = 600 viscometer dial reading
θ300 = 300 viscometer dial reading
Dh = hole diameter, in.
Dp = pipe or collar OD, in.
MW = mud weight, ppg
AVc = critical annular velocity, ft/min
GPMc = critical flow rate, gpm

Example: Mud weight = 14.0 ppg
θ600 = 64
θ300 = 37
Hole diameter = 8.5 in.
Pipe OD = 7.0 in.

1. Determine n:

$$n = 3.32 \log \frac{64}{37}$$

$$n = 0.79$$

2. Determine K:

$$K = \frac{64}{1022^{0.79}}$$

$$K = 0.2684$$

3. Determine x:

$$x = \frac{81{,}600(0.2684)(0.79)^{0.387}}{8.5 - 7^{0.79} \times 14.0}$$

$$x = \frac{19{,}967.413}{19.2859}$$

$$x = 1035$$

4. Determine critical annular velocity:

$$AVc = (1035)^{1 \div (2-0.79)}$$
$$AVc = (1035)^{0.8264}$$
$$AVc = 310 \text{ ft/min}$$

5. Determine critical flow rate:

$$GPMc = \frac{310(8.5^2 - 7.0^2)}{24.5}$$

$$GPMc = 294 \text{ gpm}$$

"d" Exponent

The "d" exponent is derived from the general drilling equation:

$$R \div N = a(W^d \div D)$$

where R = penetration rate
N = rotary speed, rpm
a = a constant, dimensionless
W = weight on bit, lb
d = exponent in general drilling equation, dimensionless

"d" exponent equation:

$$\text{"d"} = \log(R \div 60N) \div \log(12W \div 1000D)$$

where d = d exponent, dimensionless
R = penetration rate, ft/hr
N = rotary speed, rpm
W = weight on bit, 1,000 lb
D = bit size, in.

Example: R = 30 ft/hr
N = 120 rpm
W = 35,000 lb
D = 8.5 in.

Solution: $d = \log[30 \div (60 \times 120)] \div \log[(12 \times 35) \div (1000 \times 8.5)]$
$d = \log(30 \div 7200) \div \log(420 \div 8500)$
$d = \log 0.0042 \div \log 0.0494$
$d = -2.377 \div -1.306$
$d = 1.82$

Corrected "d" exponent:

The "d" exponent is influenced by mud weight variations, so modifications have to be made to correct for changes in mud weight:

$$d_c = d(MW_1 \div MW_2)$$

where de = corrected "d" exponent
MW_1 = normal mud weight—9.0 ppg
MW_2 = actual mud weight, ppg

Example: d = 1.64
MW1 = 9.0 ppg
MW2 = 12.7 ppg

Solution: $d_c = 1.64\ (9.0 \div 12.7)$
$d_c = 1.64 \times 0.71$
$d_c = 1.16$

Cuttings Slip Velocity

These calculations provide the slip velocity of a cutting of a specific size and weight in a given fluid. The annular velocity and the cutting net rise velocity are also calculated.

Method 1

Annular velocity, ft/min:

$$AV = \frac{24.5 \times Q}{Dh^2 - Dp^2}$$

Cuttings slip velocity, ft/min:

$$Vs = 0.45\left(\frac{PV}{(MW)(Dp)}\right)\left[\sqrt{\frac{36{,}800}{\left(\frac{PV}{(MW)(Dp)}\right)^2} \times (Dp)\left(\frac{DenP}{MW} - 1\right) + 1^{-1}}\right]$$

where Vs = slip velocity, ft/min
PV = plastic viscosity, cps
MW = mud weight, ppg
Dp = diameter of particle, in.
DenP = density of particle, ppg

Example: Using the following data, determine the annular velocity, ft/min; the cuttings slip velocity, ft/min, and the cutting net rise velocity, ft/min:

DATA:

Mud weight	= 11.0 ppg
Plastic viscosity	= 13 cps
Diameter of particle	= 0.25 in.
Density of particle	= 22 ppg
Flow rate	= 520 gpm
Diameter of hole	= 12–1/4 in.
Drill pipe OD	= 5.0 in.

Annular velocity, ft/min:

$$AV = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$AV = 102 \text{ ft/min}$$

Cuttings slip velocity, ft/min:

$$Vs = 0.45\left(\frac{13}{11 \times 0.25}\right)\left[\sqrt{\frac{36{,}800}{\left(\frac{13}{11 \times 0.25}\right)^2} \times 0.25\left(\frac{22}{11} - 1\right) + 1^{-1}}\right]$$

$$Vs = 0.45[4.727]\left[\sqrt{\frac{36,800}{[4.727]^2} \times 0.25 \times 1 + 1} - 1\right]$$

$$Vs = 2.12715(\sqrt{412.68639} - 1)$$

$$Vs = 2.12715 \times 19.3146$$

$$Vs = 41.085\,\text{ft/min}$$

Cuttings net rise velocity:

Annular velocity	= 102 ft/min
Cuttings slip velocity	= –41 ft/min
Cuttings net rise velocity	= 61 ft/min

Method 2

1. Determine n:

$$n = 3.32\ \log\frac{\theta 600}{\theta 300}$$

2. Determine K:

$$K = \frac{\theta 300}{511^n}$$

3. Determine annular velocity, ft/min:

$$v = \frac{24.5 \times Q}{Dh^2 - Dp^2}$$

4. Determine viscosity (μ):

$$\mu = \left(\frac{2.4v}{Dh - Dp} \times \frac{2n + 1}{3n}\right)^n \times \left(\frac{200K(Dh - Dp)}{v}\right)$$

5. Slip velocity (Vs), ft/min:

$$Vs = \frac{(DensP - MW)^{0.667} \times 175 \times DiaP}{MW^{0.333} \times \mu^{0.333}}$$

Nomenclature:

n	= dimensionless
K	= dimensionless
θ600	= 600 viscometer dial reading

θ300 = 300 viscometer dial reading
Q = circulation rate, gpm
Dh = hole diameter, in.
Dp = pipe or collar OD, in.
v = annular velocity, ft/min
μ = mud viscosity, cps
DensP = cutting density, ppg
DiaP = cutting diameter, in.

Example: Using the data listed below, determine the annular velocity, cuttings slip velocity, and the cutting net rise velocity:

DATA:	Mud weight	= 11.0 ppg
	Plastic viscosity	= 13 cps
	Yield point	= 10 lb/100 sq ft
	Diameter of particle	= 0.25 in.
	Density of particle	= 22.0 ppg
	Hole diameter	= 12.25 in.
	Drill pipe OD	= 5.0 in
	Circulation rate	= 520 gpm

1. Determine n:

$$n = 3.32 \log \frac{36}{23}$$

$$n = 0.64599$$

2. Determine K:

$$K = \frac{23}{511^{0.64599}}$$

$$K = 0.4094$$

3. Determine annular velocity, ft/min:

$$v = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$v = \frac{12,740}{125.06}$$

$$v = 102 \text{ ft/min}$$

4. Determine mud viscosity, cps:

$$\mu = \left(\frac{2.4 \times 102}{12.25 - 5.0} \times \frac{2(0.64599) + 1}{3 \times 0.64599}\right)^{0.64599} \times \left(\frac{200 \times 0.4094 \times (12.25 - 5)}{102}\right)$$

$$\mu = \left(\frac{244.8}{7.25} \times \frac{2.92}{1.938}\right)^{0.64599} \times \frac{593.63}{102}$$

$$\mu = (33.76 \times 1.1827)^{0.64599} \times 5.82$$

$$\mu = 10.82 \times 5.82$$

$$\mu = 63 \text{ cps}$$

5. Determine cuttings slip velocity, ft/min:

$$Vs = \frac{(22-11)^{0.667} \times 175 \times 0.25}{11^{0.333} \times 63^{0.333}}$$

$$Vs = \frac{4.95 \times 175 \times 0.25}{2.222 \times 3.97}$$

$$Vs = \frac{216.56}{8.82}$$

$$Vs = 24.55 \text{ ft/min}$$

6. Determine cuttings net rise velocity, ft/min:

Annular velocity	=	102 ft/min
Cuttings slip velocity	=	–24.55 ft/min
Cuttings net rise velocity	=	77.45 ft/min

Surge and Swab Pressures

Method 1

1. Determine n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300}$$

2. Determine K:

$$K = \frac{\theta 300}{511^n}$$

3. Determine velocity, ft/min:

For plugged flow:

$$v = \left[0.45 + \frac{Dp^2}{Dh^2 - Dp^2}\right]Vp$$

For open pipe:

$$v = \left[0.45 + \frac{Dp^2 - Di^2}{Dh^2 - Dp^2 + Di^2}\right]Vp$$

4. Maximum pipe velocity:

$$Vm = 1.5 \times v$$

5. Determine pressure losses:

$$Ps = \left(\frac{2.4\,Vm}{Dh - Dp} \times \frac{2n + 1}{3n}\right)^n \times \frac{KL}{300(Dh - Dp)}$$

Nomenclature:

n = dimensionless
K = dimensionless
θ600 = 600 viscometer dial reading
θ300 = 300 viscometer dial reading
v = fluid velocity, ft/min
Vp = pipe velocity, ft/min
Vm = maximum pipe velocity, ft/min
Ps = pressure loss, psi
L = pipe length, ft
Dh = hole diameter, in.
Dp = drill pipe or drill collar OD, in.
Di = drill pipe or drill collar ID, in.

Example 1: Determine surge pressure for plugged pipe:

Date:	Well depth	= 15,000 ft
	Hole size	= 7-7/8 in.
	Drill pipe OD	= 4-1/2 in.
	Drill pipe ID	= 3.82 in.
	Drill collar	= 6-1/4″ O.D. × 2-3/4″ ID
	Drill collar length	= 700 ft
	Mud weight	= 15.0 ppg

Viscometer readings:
θ600 = 140
θ300 = 80
Average pipe running speed = 270 ft/min

1. Determine n:

$$n = 3.32 \log \frac{140}{80}$$

$$n = 0.8069$$

2. Determine K:

$$K = \frac{80}{511^{0.8069}}$$

$$K = 0.522$$

3. Determine velocity, ft/min:

$$V = \left[0.45 + \frac{(4.5)^2}{7.875^2 - 4.5^2}\right]270$$

$$V = (0.45 + 0.484)270$$

$$V = 252\ \text{ft/min}$$

4. Determine maximum pipe velocity, ft/min:

$$Vm = 252 \times 1.5$$
$$Vm = 378\ \text{ft/min}$$

5. Determine pressure loss, psi:

$$Ps = \left[\frac{2.4 \times 378}{7.875 - 4.5} \times \frac{2(0.8069) + 1}{3(0.8069)}\right]^{0.8069} \times \frac{(0.522)(14{,}300)}{300(7.875 - 4.5)}$$

$$Ps = (268.8 \times 1.1798)^{0.8069} \times \frac{7464.6}{1012.5}$$

$$Ps = 97.098 \times 7.37$$

$$Ps = 716\ \text{psi surge pressure}$$

Therefore, this pressure is added to the hydrostatic pressure of the mud in the wellbore.

If, however, the swab pressure is desired, this pressure would be subtracted from the hydrostatic pressure.

Example 2: Determine surge pressure for open pipe:

1. Determine velocity, ft/min:

$$v = \left[0.45 + \frac{4.5^2 - 3.82^2}{7.875^2 - 4.5^2 + 3.82^2}\right]270$$

$$v = \left(0.45 + \frac{5.66}{56.4}\right)270$$

$$v = (0.45 + 0.100)270$$

$$v = 149\,\text{ft/min}$$

2. Maximum pipe velocity, ft/min:

$$Vm = 149 \times 1.5$$
$$Vm = 224\,\text{ft/min}$$

3. Pressure loss, psi:

$$Ps = \left[\frac{2.4 \times 224}{7.875 - 4.5} \times \frac{2(0.8069) + 1}{3(0.8069)}\right]^{0.8069} \times \frac{(0.522)(14{,}300)}{300(7.875 - 4.5)}$$

$$Ps = (159.29 \times 1.0798)^{0.8069} \times \frac{7464.6}{1012.5}$$

$$Ps = 63.66 \times 7.37$$

$$Ps = 469\,\text{psi surge pressure}$$

Therefore, this pressure would be added to the hydrostatic pressure of the mud in the wellbore.

If, however, the swab pressure is desired, this pressure would be subtracted from the hydrostatic pressure of the mud in the wellbore.

Method 2

Surge and swab pressures

Assume: 1) Plugged pipe
2) Laminar flow around drill pipe
3) Turbulent flow around drill collars

These calculations outline the procedure and calculations necessary to determine the increase or decrease in equivalent mud weight (bottomhole pressure) due to pressure surges caused by pulling or running pipe. These calculations assume that the end of the pipe is plugged (as in running casing with a float shoe or drill pipe with bit and jet nozzles in place), not open-ended.

A. Surge pressure around drill pipe:

1. Estimated annular fluid velocity (v) around drill pipe:

$$v = \left[0.45 + \frac{Dp^2}{Dh^2 - Dp^2}\right]Vp$$

2. Maximum pipe velocity (Vm):

$$Vm = v \times 1.5$$

3. Calculate n:

$$n = 3.32 \log\frac{\theta600}{\theta300}$$

4. Calculate K:

$$K = \frac{\theta300}{511^n}$$

5. Calculate the shear rate (Ym) of the mud moving around the pipe:

$$Ym = \frac{2.4 \times Vm}{Dh - Dp}$$

6. Calculate the shear stress (T) of the mud moving around the pipe:

$$T = K(Ym)^n$$

7. Calculate the pressure (Ps) decrease for the interval:

$$Ps = \frac{3.33T}{Dh - Dp} \times \frac{L}{1000}$$

B. Surge pressure around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$v = \left[0.45 + \frac{Dp^2}{Dh^2 - Dp^2}\right]Vp$$

2. Calculate maximum pipe velocity (Vm):

$$Vm = v \times 1.5$$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flowrate (Q):

$$Q = \frac{Vm\left[(Dh)^2 - (Dp)^2\right]}{24.5}$$

4. Calculate the pressure loss for each interval (Ps):

$$Ps = \frac{0.000077 \times MW^{0.8} \times Q^{1.8} \times PV^{0.2} \times L}{(Dh - Dp)^3 \times (Dh + Dp)^{1.8}}$$

C. Total surge pressures converted to mud weight:

Total surge (or swab) pressures:

psi = Ps(drill pipe) + Ps(drill collars)

D. If surge pressure is desired:

SP, ppg = Ps ÷ 0.052 ÷ TVD, ft "+" MW, ppg

E. If swab pressure is desired:

SP, ppg = Ps ÷ 0.052 ÷ TVD, ft "−" MW, ppg

Example: Determine both the surge and swab pressure for the data listed below:

Data:	Mud weight	= 15.0 ppg
	Plastic viscosity	= 60 cps
	Yield point	= 20 lb/100 sq ft
	Hole diameter	= 7-7/8 in.
	Drill pipe OD	= 4-1/2 in.
	Drill pipe length	= 14,300 ft
	Drill collar OD	= 6-1/4 in.
	Drill collar length	= 700 ft
	Pipe running speed	= 270 ft/min

A. Around drill pipe:

1. Calculate annular fluid velocity (v) around drill pipe:

$$v = \left[0.45 + \frac{(4.5)^2}{7.875^2 - 4.5^2}\right]270$$

$$v = [0.45 + 0.4848]270$$

$$v = 253\ \text{ft/min}$$

2. Calculate maximum pipe velocity (Vm):

$$Vm = 253 \times 1.5$$

$$Vm = 379\,\text{ft/min}$$

NOTE: Determine n and K from the plastic viscosity and yield point as follows:

$$PV + YP = \theta 300 \text{ reading}$$

$$\theta 300 \text{ reading} + PV = \theta 600 \text{ reading}$$

Example: PV = 60
YP = 20

$$60 + 20 = 80\ (\theta 300 \text{ reading})$$

$$80 + 60 = 140\ (\theta 600 \text{ reading})$$

3. Calculate n:

$$n = 3.32\ \log 80 \frac{140}{80}$$

$$n = 0.8069$$

4. Calculate K:

$$K = \frac{80}{511^{0.8069}}$$

$$K = 0.522$$

5. Calculate the shear rate (Ym) of the mud moving around the pipe:

$$Ym = \frac{2.4 \times 379}{(7.875 - 4.5)}$$

$$Ym = 269.5$$

6. Calculate the shear stress (T) of the mud moving around the pipe:

$$T = 0.522(269.5)^{0.8069}$$
$$T = 0.522 \times 91.457$$
$$T = 47.74$$

7. Calculate the pressure decrease (Ps) for the interval:

$$Ps = \frac{3.33(47.7)}{(7.875-4.5)} \times \frac{14{,}300}{1000}$$

$$Ps = 47.064 \times 14.3$$

$$Ps = 673\,\text{psi}$$

B. Around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$v = \left[0.45 + \frac{6.25^2}{7.875^2 - 6.25^2}\right]270$$

$$v = (0.45 + 1.70)270$$

$$v = 581\,\text{ft/min}$$

2. Calculate maximum pipe velocity (Vm):

$$Vm = 581 \times 1.5$$
$$Vm = 871.54\,\text{ft/min}$$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flowrate (Q):

$$Q = \frac{871.54(7.875^2 - 6.25^2)}{24.5}$$

$$Q = \frac{20{,}004.567}{24.5}$$

$$Q = 816.5$$

4. Calculate the pressure loss (Ps) for the interval:

$$Ps = \frac{0.000077 \times 15^{0.8} \times 816^{1.8} \times 60^{0.2} \times 700}{(7.875 - 6.25)^3 \times (7.875 + 6.25)^{1.8}}$$

$$Ps = \frac{185{,}837.9}{504.126}$$

$$Ps = 368.6\,\text{psi}$$

C. Total pressures:

psi = 672.9 psi + 368.6 psi
psi = 1041.5 psi

D. Pressure converted to mud weight, ppg:

ppg = 1041.5 psi ÷ 0.052 ÷ 15,000 ft
ppg = 1.34

E. If surge pressure is desired:

Surge pressure, ppg = 15.0 ppg + 1.34 ppg
Surge pressure = 16.34 ppg

F. If swab pressure is desired:

Swab pressure, ppg = 15.0 ppg − 1.34 ppg
Swab pressure = 13.66 ppg

Equivalent Circulation Density (ECD)

1. Determine n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300}$$

2. Determine K:

$$K = \frac{\theta 300}{511^n}$$

3. Determine annular velocity (v), ft/min:

$$v = \frac{24.5 \times Q}{Dh^2 - Dp^2}$$

4. Determine critical velocity (Vc), ft/min:

$$Vc = \left(\frac{3.878 \times 10^4 \times K}{MW}\right)^{\frac{1}{2-n}} \times \left(\frac{2.4}{Dh - Dp} \times \frac{2n + 1}{3n}\right)^{\frac{n}{2-n}}$$

5. Pressure loss for laminar flow (Ps), psi:

$$Ps = \left(\frac{2.4v}{Dh - Dp} \times \frac{2n + 1}{3n}\right)^n \times \frac{KL}{300(Dh - Dp)}$$

6. Pressure loss for turbulent flow (Ps), psi:

$$Ps = \frac{7.7 \times 10^{-5} \times MW^{0.8} \times Q^{1.8} \times PV^{0.2} \times L}{(Dh - Dp)^3 \times (Dh + Dp)^{1.8}}$$

7. Determine equivalent circulating density (ECD), ppg:

ECD, ppg = Ps ÷ 0.052 ÷ TVD, ft + OMW, ppg

Example: Equivalent circulating density (ECD), ppg:

Date:	Mud weight	= 12.5 ppg
	Plastic viscosity	= 24 cps
	Yield point	= 12 lb/100 sq ft
	Circulation rate	= 400 gpm
	Hole diameter	= 8.5 in.
	Drill pipe OD	= 5.0 in.
	Drill pipe length	= 11,300 ft
	Drill collar OD	= 6.5 in.
	Drill collar length	= 700 ft
	True vertical depth	= 12,000 ft

NOTE: If θ600 and θ300 viscometer dial readings are unknown, they may be obtained from the plastic viscosity and yield point as follows:

24 + 12 = 36 Thus, 36 is the θ300 reading.

36 + 24 = 60 Thus, 60 is the θ600 reading.

1. Determine n:

$$n = 3.32 \log \frac{60}{36}$$

n = 0.7365

2. Determine K:

$$K = \frac{36}{511^{0.7365}}$$

K = 0.3644

3a. Determine annular velocity (v), ft/min, around drill pipe:

$$v = \frac{24.5 \times 400}{8.5^2 - 5.0^2}$$

$$v = 207 \text{ ft/min}$$

3b. Determine annular velocity (v), ft/min, around drill collars:

$$v = \frac{24.5 \times 400}{8.5^2 - 6.5^2}$$

$$v = 327 \text{ ft/min}$$

4a. Determine critical velocity (Vc), ft/min, around drill pipe:

$$Vc = \left(\frac{3.878 \times 10^4 \times .3644}{12.5}\right)^{\frac{1}{2-.7365}} \times \left(\frac{2.4}{8.5 - 5} \times \frac{2(.7365) + 1}{3(.7365)}\right)^{\frac{.7365}{2-.7365}}$$

$$Vc = (1130.5)^{0.791} \times (0.76749)^{0.5829}$$

$$Vc = 260 \times 0.857$$

$$Vc = 223 \text{ ft/min}$$

4b. Determine critical velocity (Vc), ft/min, around drill collars:

$$Vc = \left(\frac{3.878 \times 10^4 \times .3644}{12.5}\right)^{\frac{1}{2-.7365}} \times \left(\frac{2.4}{8.5 - 6.5} \times \frac{2(.7365) + 1}{3(.7365)}\right)^{\frac{.7365}{2-.7365}}$$

$$Vc = (1130.5)^{0.791} \times (1.343)^{0.5829}$$

$$Vc = 260 \times 1.18756$$

$$Vc = 309 \text{ ft/min}$$

Therefore:

Drill pipe: 207 ft/min (v) is less than 223 ft/min (Vc). Laminar flow, so use Equation 5 for pressure loss.

Drill collars: 327 ft/min (v) is greater than 309 ft/min (Vc) turbulent flow, so use Equation 6 for pressure loss.

5. Pressure loss opposite drill pipe:

$$Ps = \left[\frac{2.4 \times 207}{8.5 - 5.0} \times \frac{2(.7365) + 1}{3(.7365)}\right]^{.7365} \times \frac{.3644 \times 11{,}300}{300(8.5 - 5.0)}$$

$Ps = (141.9 \times 1.11926)^{0.7365} \times 3.9216$

$Ps = 41.78 \times 3.9216$

$Ps = 163.8\,psi$

6. Pressure loss opposite drill collars:

$$Ps = \frac{7.7 \times 10^{-5} \times 12.5^{0.8} \times 400^{1.8} \times 24^{0.2} \times 700}{(8.5 - 6.5)^3 \times (8.5 + 6.5)^{1.8}}$$

$$Ps = \frac{37{,}056.7}{8 \times 130.9}$$

$Ps = 35.4\,psi$

Total pressure losses:

$psi = 163.8\,psi + 35.4\,psi$

$psi = 199.2\,psi$

7. Determine equivalent circulating density (ECD), ppg:

ECD, ppg $= 199.2\,psi \div 0.052 \div 12{,}000\,ft + 12.5\,ppg$

ECD $= 12.82\,ppg$

Fracture Gradient Determination—Surface Application

Method 1: Matthews and Kelly Method

$F = P/D + Ki\,\sigma/D$

where F = fracture gradient, psi/ft
P = formation pore pressure, psi
σ = matrix stress at point of interest, psi
D = depth at point of interest, TVD, ft
Ki = matrix stress coefficient, dimensionless

Procedure:

1. Obtain formation pore pressure, P, from electric logs, density measurements, or mud logging personnel.
2. Assume 1.0 psi/ft as overburden pressure (S) and calculate σ as follows:

   $\sigma = S - P$

3. Determine the depth for determining Ki by:

$$D = \frac{\sigma}{0.535}$$

4. From Matrix Stress Coefficient chart, determine K:

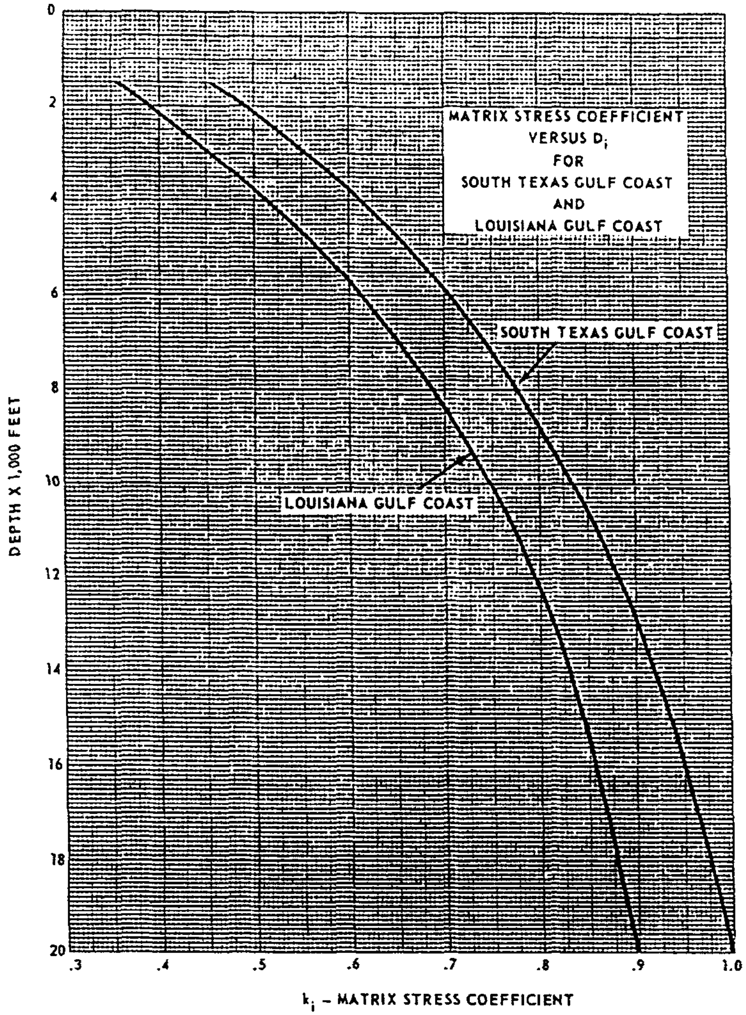


Figure 5-1. Matrix stress coefficient chart.

5. Determine fracture gradient, psi/ft:

$$F = \frac{P}{D} + Ki \times \frac{\sigma}{D}$$

6. Determine fracture pressure, psi:

F, psi = F × D

7. Determine maximum mud density, ppg:

$$MW, ppg = \frac{F}{0.052}$$

Example: Casing setting depth = 12,000 ft
Formation pore pressure = 12.0 ppg
(Louisiana Gulf Coast)

1. P = 12.0 ppg × 0.052 × 12,000 ft

P = 7488 psi

2. σ = 12,000 psi − 7488 psi

σ = 4512 psi

3. $$D = \frac{4512 \text{ psi}}{0.535}$$

D = 8434 ft

4. From chart = Ki = 0.79 psi/ft

5. $$F = \frac{7488}{12{,}000} + 0.79 \times \frac{4512}{12{,}000}$$

F = 0.624 psi/ft + 0.297 psi/ft

F = 0.92 psi/ft

6. Fracture pressure, psi = 0.92 psi/ft × 12,000 ft

Fracture pressure = 11,040 psi

7. $$\text{Maximum mud density, ppg} = \frac{0.92 \text{ psi/ft}}{0.052}$$

Maximum mud density = 17.69 ppg

Method 2: Ben Eaton Method

$$F = \left(\frac{S}{D} - \frac{Pf}{D}\right) \times \left(\frac{y}{1 - y}\right) + \left(\frac{Pf}{D}\right)$$

where S/D = overburden gradient, psi/ft
Pf/D = formation pressure gradient at depth of interest, psi/ft
y = Poisson's ratio

Procedure:

1. Obtain overburden gradient from "Overburden Stree Gradient Chart."
2. Obtain formation pressure gradient from electric logs, density measurements, or logging operations.
3. Obtain Poisson's ratio from "Poisson's Ratio Chart."
4. Determine fracture gradient using above equation.
5. Determine fracture pressure, psi:

   $$\text{psi} = F \times D$$

6. Determine maximum mud density, ppg:

   $$\text{ppg} = \frac{F}{0.052}$$

Example: Casing setting depth = 12,000 ft
Formation pore pressure = 12.0 ppg

1. Determine S/D from chart = depth = 12,000 ft

   S/D = 0.96 psi/ft

2. Pf/D = 12.0 ppg × 0.052 = 0.624 psi/ft
3. Poisson's Ratio from chart = 0.47 psi/ft
4. Determine fracture gradient:

   $$F = (0.96 - 0.6243)\left(\frac{0.47}{1 - 0.47}\right) + 0.624$$

   $$F = 0.336 \times 0.88679 + 0.624$$

   $$F = 0.29796 + 0.624$$

   $$F = 0.92\,\text{psi/ft}$$

5. Determine fracture pressure:

$$psi = 0.92\,psi/ft \times 12{,}000\,ft$$

$$psi = 11{,}040$$

6. Determine maximum mud denisty:

$$pg = \frac{0.92\ psi/ft}{0.052}$$

$$ppg = 17.69$$

Fracture Gradient Determination—Subsea Applications

In offshore drilling operations, it is necessary to correct the calculated fracture gradient for the effect of water depth and flowline height (air gap) above mean sea level. The following procedure can be used:

Example: Air gap = 100 ft
Density of seawater = 8.9 ppg
Water depth = 2000 ft
Feet of casing below mudline = 4000 ft

Procedure:

1. Convert water to equivalent land area, ft:
   a) Determine the hydrostatic pressure of the seawater:

$$HPsw = 8.9\,ppg \times 0.052 \times 2000\,ft$$

$$HPsw = 926\,psi$$

   b) From Eaton's Overburden Stress Chart, determine the overburden stress gradient from mean sea level to casing setting depth:

   From chart: Enter chart at 6000 ft on left; intersect curved line and read overburden gradient at bottom of chart:

   Overburden stress gradient = 0.92 psi/ft

   c) Determine equivalent land area, ft:

$$\text{Equivalent feet} = \frac{926\ psi}{0.92\ psi/ft}$$

$$\text{Equivalent feet} = 1006$$

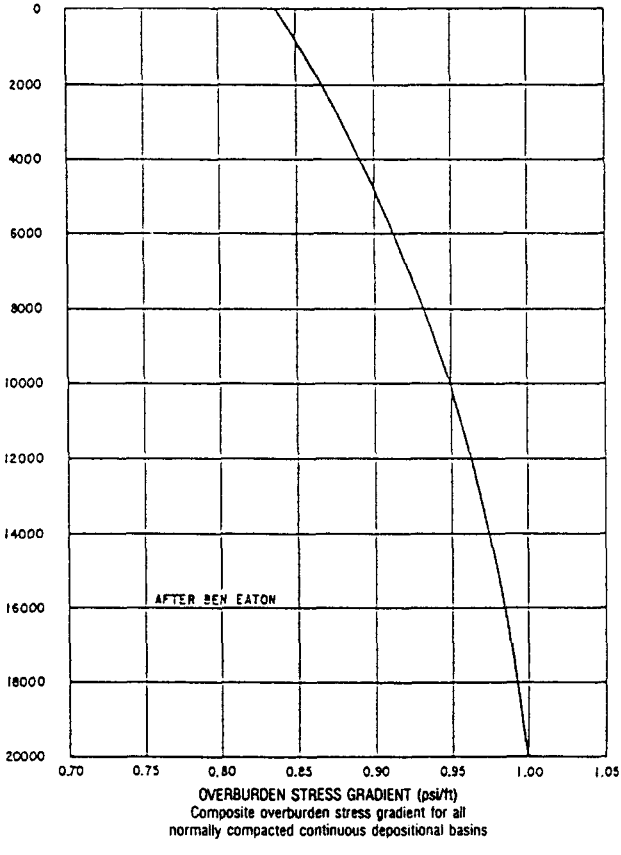


Figure 5-2. Eaton's overburden stress chart.

2. Determine depth for fracture gradient determination:

   Depth, ft = 4000 ft + 1006 ft
   Depth = 5006 ft

3. Using Eaton's Fracture Gradient Chart, determine the fracture gradient at a depth of 5006 ft:

   From chart: Enter chart at a depth of 5006 ft; intersect the 9.0 ppg line; then proceed up and read the fracture gradient at the top of the chart:

   Fracture gradient = 14.7 ppg

4. Determine the fracture pressure:

$$\text{psi} = 14.7\,\text{ppg} \times 0.052 \times 5006\,\text{ft}$$
$$\text{psi} = 3827$$

5. Convert the fracture gradient relative to the flowline:

$$\text{Fc} = 3827\,\text{psi} \div 0.052 \div 6100\,\text{ft}$$
$$\text{Fc} = 12.06\,\text{ppg}$$

where Fc is the fracture gradient, corrected for water depth, and air gap.

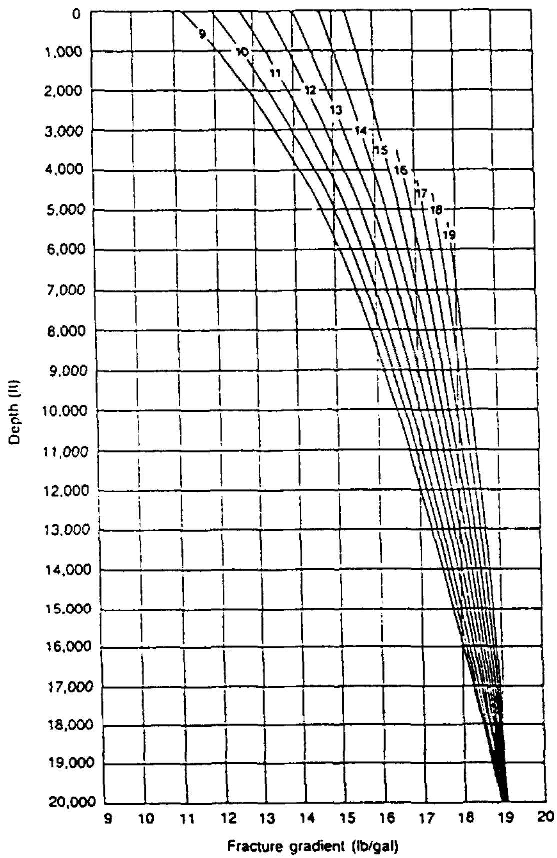


Figure 5-3. Eaton's fracture gradient chart.

Directional Drilling Calculations

Directional survey calculations

The following are the two most commonly used methods to calculate directional surveys:

1. Angle Averaging Method

$$\text{North} = \text{MD} \times \sin\frac{(\text{I1} + \text{I2})}{2} \times \cos\frac{(\text{A1} + \text{A2})}{2}$$

$$\text{East} = \text{MD} \times \sin\frac{(\text{I1} + \text{I2})}{2} \times \sin\frac{(\text{A1} + \text{A2})}{2}$$

$$\text{Vert} = \text{MD} \times \cos\frac{(\text{I1} + \text{I2})}{2}$$

2. Radius of Curvature Method

$$\text{North} = \frac{\text{MD}(\cos \text{I1} - \cos \text{I2})(\sin \text{A2} - \sin \text{A1})}{(\text{I2} - \text{I1})(\text{A2} - \text{A1})}$$

$$\text{East} = \frac{\text{MD}(\cos \text{I1} - \cos \text{I2})(\cos \text{A1} - \cos \text{A2})}{(\text{I2} - \text{I1})(\text{A2} - \text{A1})}$$

$$\text{Vert} = \frac{\text{MD}(\sin \text{I2} - \sin \text{I1})}{(\text{I2} - \text{I1})}$$

where MD = course length between surveys in measured depth, ft
I_1, I_2 = inclination (angle) at upper and lower surveys, degrees
A_1, A_2 = direction at upper and lower surveys

Example: Use the Angle Averaging Method and the Radius of Curvature Method to calculate the following surveys:

	Survey 1	**Survey 2**
Depth, ft	7482	7782
Inclination, degrees	4	8
Azimuth, degrees	10	35

Angle Averaging Method:

$$\text{North} = 300 \times \sin\frac{(4 + 8)}{2} \times \cos\frac{(10 + 35)}{2}$$

$$= 300 \times \sin(6) \times \cos(22.5)$$

$$= 300 \times .104528 \times .923879$$

$$\text{North} = 28.97 \text{ ft}$$

$$\text{East} = 300 \times \sin\frac{(4 + 8)}{2} \times \sin\frac{(10 + 35)}{2}$$

$$= 300 \times \sin(6) \times \sin(22.5)$$

$$= 300 \times .104528 \times .38268$$

$$\text{East} = 12.0 \text{ ft}$$

$$\text{Vert} = 300 \times \cos\frac{(4 + 8)}{2}$$

$$= 300 \times \cos(6)$$

$$= 300 \times .99452$$

$$\text{Vert} = 298.35 \text{ ft}$$

Radius of Curvature Method:

$$\text{North} = \frac{300(\cos 4 - \cos 8)(\sin 35 - \sin 10)}{(8 - 4)(35 - 10)}$$

$$= \frac{300(.99756 - .990268)(.57357 - .173648)}{4 \times 25}$$

$$= \frac{.874629}{100}$$

$$= 0.008746 \times 57.3^2$$

$$\text{North} = 28.56 \text{ ft}$$

$$\text{East} = \frac{300(\cos 4 - \cos 8)(\cos 10 - \cos 35)}{(8 - 4)(35 - 10)}$$

$$= \frac{300(.99756 - .99026)(.9848 - .81915)}{4 \times 25}$$

$$= \frac{300(.0073)(.16565)}{100}$$

$$= \frac{0.36277}{100}$$

$$= 0.0036277 \times 57.3^2$$

$$\text{East} = 11.91\,\text{ft}$$

$$\text{Vert} = \frac{300(\sin 8 - \sin 4)}{(8 - 4)}$$

$$= \frac{300(.13917 \times .069756)}{4}$$

$$= \frac{300 \times .069414}{4}$$

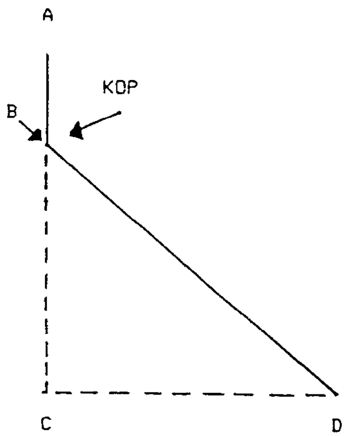
$$= 5.20605 \times 57.3$$

$$\text{Vert} = 298.3\,\text{ft}$$

Deviation/departure calculation

Deviation is defined as departure of the wellbore from the vertical, measured by the horizontal distance from the rotary table to the target. The amount of deviation is a function of the drift angle (inclination) and hole depth.

The following diagram illustrates how to determine the deviation/departure:



DATA:

AB = distance from the surface location to the KOP
BC = distance from KOP to the true vertical depth (TVD)
BD = distance from KOP to the bottom of the hole (MD)
CD = deviation/departure–departure of the wellbore from the vertical
AC = true vertical depth
AD = measured depth

Figure 5-4. Deviation/Departure.

To calculate the deviation/departure (CD), ft:

$$CD, ft = \sin I \times BD$$

Example: Kick off point (KOP) is a distance 2000 ft from the surface. MD is 8000 ft. Hole angle (inclination) is 20 degrees. Therefore the distance from KOP to MD = 6000 ft (BD):

$$\begin{aligned} CD, ft &= \sin 20 \times 6000\,ft \\ &= 0.342 \times 6000\,ft \\ CD &= 2052\,ft \end{aligned}$$

From this calculation, the measured depth (MD) is 2052 ft away from vertical.

Dogleg severity calculation

Method 1

Dogleg severity (DLS) is usually given in degrees/100 ft. The following formula provides dogleg severity in degrees/100 ft and is based on the Radius of Curvature Method:

$$DLS = \{\cos^{-1}[(\cos I1 \times \cos I2) + (\sin I1 \times \sin I2) \times \cos(A2 - A1)]\} \times \frac{100}{CL}$$

For metric calculation, substitute $\times \frac{30}{CL}$

where DLS = dogleg severity, degrees/100 ft
CL = course length, distance between survey points, ft
I1, I2 = inclination (angle) at upper and lower surveys, ft
A1, A2 = direction at upper and lower surveys, degrees
^Azimuth = azimuth change between surveys, degrees

Example:

	Survey 1	**Survey 2**
Depth, ft	4231	4262
Inclination, degrees	13.5	14.7
Azimuth, degrees	N 10 E	N 19 E

$$\text{DLS} = \{\cos^{-1}[(\cos 13.5 \times \cos 14.7) + (\sin 13.5 \times \sin 14.7 \times \cos(19 - 10))]\} \times \frac{100}{31}$$

$$\text{DLS} = \{\cos^{-1}[(.9723699 \times .9672677) + (.2334453 \times .2537579 \times .9876883)]\} \times \frac{100}{31}$$

$$\text{DLS} = \{\cos^{-1}[(.940542) + (.0585092)]\} \times \frac{100}{31}$$

$$\text{DLS} = 2.4960847 \times \frac{100}{31}$$

$$\text{DLS} = 8.051886 \text{ degrees/100 ft}$$

Method 2

This method of calculating dogleg severity is based on the tangential method:

$$\text{DLS} = \frac{100}{\text{L}[(\sin \text{I1} \times \sin \text{I2})(\sin \text{A1} \times \sin \text{A2} + \cos \text{A1} \times \cos \text{A2}) + \cos \text{I1} \times \cos \text{I2}]}$$

where DLS = dogleg severity, degrees/100 ft
L = course length, ft
I1, I2 = inclination (angle) at upper and lower surveys, degrees
A1, A2 = direction at upper and lower surveys, degrees

Example:

	Survey 1	Survey 2
Depth	4231	4262
Inclination, degrees	13.5	14.7
Azimuth, degrees	N 10 E	N 19 E

Dogleg severity =

$$\frac{100}{31[(\sin 13.5 \times \sin 14.7)(\sin 10 \times \sin 19) + (\cos 10 \times \cos 19) + (\cos 13.5 \times \cos 14.7)]}$$

$$\text{DLS} = \frac{100}{30.969}$$

$$\text{DLS} = 3.229 \text{ degrees/100 ft}$$

Available weight on bit in directional wells

A directionally drilled well requires that a correction be made in total drill collar weight because only a portion of the total weight will be available to the bit:

$$P = W \times \cos I$$

where P = partial weight available for bit
cos = cosine
I = degrees inclination (angle)
W = total weight of collars

Example: W = 45,000 lb
I = 25 degrees
P = 45,000 × cos 25
P = 45,000 × 0.9063
P = 40,784 lb

Thus, the available weight on bit is 40,784 lb.

Determining true vertical depth

The following is a simple method of correcting for the TVD on directional wells. This calculation will provide the approximate TVD interval corresponding to the measured interval and is generally accurate enough for any pressure calculations. At the next survey, the TVD should be corrected to correspond to the directional driller's calculated true vertical depth:

$$TVD_2 = \cos I \times CL + TVD_1$$

where TVD_2 = new true vertical depth, ft
cos = cosine
CL = course length—number of feet since last survey
TVD_1 = last true vertical depth, ft

Example: TVD (last survey) = 8500 ft
Deviation angle = 40 degrees
Course length = 30 ft

Solution: $TVD_2 = \cos 40 \times 30\,ft + 8500\,ft$
$TVD_2 = 0.766 \times 30\,ft + 8500\,ft$
$TVD_2 = 22.98\,ft + 8500\,ft$
$TVD_2 = 8522.98\,ft$

Miscellaneous Equations and Calculations

Surface Equipment Pressure Losses

$$SEpl = C \times MW \times \left(\frac{Q}{100}\right)^{1.86}$$

where SEpl = surface equipment pressure loss, psi
C = friction factor for type of surface equipment
W = mud weight, ppg
Q = circulation rate, gpm

Type of Surface Equipment	C
1	1.0
2	0.36
3	0.22
4	0.15

Example: Surface equipment type = 3
C = 0.22
Mud weight = 11.8 ppg
Circulation rate = 350 gpm

$$SEpl = 0.22 \times 11.8 \times \left(\frac{350}{100}\right)^{1.86}$$

$$SEpl = 2.596 \times (3.5)^{1.86}$$

$$SEpl = 2.596 \times 10.279372$$

$$SEpl = 26.69\,psi$$

Drill stem bore pressure losses

$$P = \frac{0.000061 \times MW \times L \times Q^{1.86}}{d^{4.86}}$$

where P = drill stem bore pressure losses, psi
MW = mudweigh, ppg
L = length of pipe, ft
Q = circulation rate, gpm
d = inside diameter, in.

Example: Mud weight = 10.9 ppg
Length of pipe = 6500 ft
Circulation rate = 350 gpm
Drill pipe ID = 4.276 in.

$$P = \frac{0.000061 \times 10.9 \times 6500 \times (350)^{1.86}}{4.276^{4.86}}$$

$$P = \frac{4.32185 \times 53{,}946.909}{1166.3884}$$

$$P = 199.89 \text{ psi}$$

Annular pressure losses

$$P = \frac{(1.4327 \times 10^{-7}) \times MW \times L \times V^2}{Dh - Dp}$$

where P = annular pressure losses, psi
MW = mud weight, ppg
L = length, ft
V = annular velocity, ft/min
Dh = hole or casing ID, in.
Dp = drill pipe or drill collar OD, in.

Example: Mud weight = 12.5 ppg
Length = 6500 ft
Circulation rate = 350 gpm
Hole size = 8.5 in.
Drill pipe OD = 5.0 in.

Determine annular velocity, ft/min:

$$v = \frac{24.5 \times 350}{8.5^2 - 5.0^2}$$

$$v = \frac{8575}{47.25}$$

$$v = 181\,\text{ft/min}$$

Determine annular pressure losses, psi:

$$P = \frac{(1.4327 \times 10^{-7}) \times 12.5 \times 6500 \times 181^2}{8.5 - 5.0}$$

$$P = \frac{381.36}{3.5}$$

$$P = 108.96\,\text{psi}$$

Pressure loss through common pipe fittings

$$P = \frac{K \times MW \times Q^2}{12{,}031 \times A^2}$$

where P = pressure loss through common pipe fittings
K = loss coefficient (See chart below)
MW = weight of fluid, ppg
Q = circulation rate, gpm
A = area of pipe, sq in.

List of Loss Coefficients (K)

K = 0.42 for 45 degree ELL
K = 0.90 for 90 degree ELL
K = 1.80 for tee
K = 2.20 for return bend
K = 0.19 for open gate valve
K = 0.85 for open butterfly valve

Example: K = 0.90 for 90 degree ELL
MW = 8.33 ppg (water)
Q = 100 gpm
A = 12.5664 sq. in. (4.0 in. ID pipe)

$$P = \frac{0.90 \times 8.33 \times 100^2}{12{,}031 \times 12.5664^2}$$

$$P = \frac{74,970}{1,899,868.3}$$

$$P = 0.03946 \text{ psi}$$

Minimum flowrate for PDC bits

Minimum flowrate, gpm = 12.72 × bit diameter, in.$^{1.47}$

Example: Determine the minimum flowrate for a 12-1/4 in. PDC bit:

Minimum flowrate, gpm = $12.72 \times 12.25^{1.47}$
Minimum flowrate, gpm = 12.72×39.77
Minimum flowrate = 505.87 gpm

Critical RPM: RPM to avoid due to excessive vibration (accurate to approximately 15%)

$$\text{Critical RPM} = \frac{33,055}{\text{L, ft}^2} \times \sqrt{\text{OD, in.}^2 + \text{ID, in.}^2}$$

Example: L = length of one joint of drill pipe = 31 ft
OD = drill pipe outside diameter = 5.0 in.
ID = drill pipe inside diameter = 4.276 in.

$$\text{Critical RPM} = \frac{33,055}{31^2} \times \sqrt{5.0^2 + 4.276^2}$$

$$\text{Critical RPM} = \frac{33,055}{961} \times \sqrt{43.284}$$

$$\text{Critical RPM} = 34.3965 \times 6.579$$

$$\text{Critical RPM} = 226.296$$

NOTE: As a rule of thumb, for 5.0 in. drill pipe, do not exceed 200 RPM at any depth.

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APPENDIX A

Table A-1
DRILL PIPE CAPACITY AND DISPLACEMENT (English System)

Size OD in.	Size ID in.	WEIGHT lb/ft	CAPACITY bbl/ft	DISPLACEMENT bbl/ft
2-3/8	1.815	6.65	0.00320	0.00279
2-7/8	2.150	10.40	0.00449	0.00354
3-1/2	2.764	13.30	0.00742	0.00448
3-1/2	2.602	15.50	0.00658	0.00532
4	3.340	14.00	0.01084	0.00471
4-1/2	3.826	16.60	0.01422	0.00545
4-1/2	3.640	20.00	0.01287	0.00680
5	4.276	19.50	0.01766	0.00652
5	4.214	20.50	0.01730	0.00704
5-1/2	4.778	21.90	0.02218	0.00721
5-1/2	4.670	24.70	0.02119	0.00820
5-9/16	4.859	22.20	0.02294	0.00712
6-5/8	5.9625	25.20	0.03456	0.00807

Table A-2
HEAVY WEIGHT DRILL PIPE AND DISPLACEMENT

Size OD in.	Size ID in.	WEIGHT lb/ft	CAPACITY bbl/ft	DISPLACEMENT bbl/ft
3-1/2	2.0625	25.3	0.00421	0.00921
4	2.25625	29.7	0.00645	0.01082
4-1/2	2.75	41.0	0.00743	0.01493
5	3.0	49.3	0.00883	0.01796

Additional capacities, bbl/ft, displacements, bbl/ft and weight, lb/ft can be determined from the following:

$$\text{Capacity, bbl/ft} = \frac{\text{ID, in.}^2}{1029.4}$$

$$\text{Displacement, bbl/ft} = \frac{\text{Dh, in.} - \text{Dp, in.}^2}{1029.4}$$

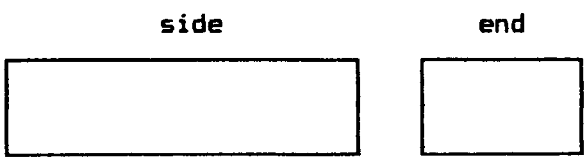
Weight, lb/ft = Displacement, bbl/ft × 2747 lb/bbl

Table A-3
DRILL PIPE CAPACITY AND DISPLACEMENT (Metric System)

Size OD in.	Size ID in.	WEIGHT lb/ft	CAPACITY Ltrs/ft	DISPLACEMENT Ltrs/ft
2-3/8	1.815	6.65	1.67	1.19
2-7/8	2.150	10.40	2.34	1.85
3-1/2	2.764	13.30	3.87	2.34
3-1/2	2.602	15.50	3.43	2.78
4	3.340	14.00	5.65	2.45
4-1/2	3.826	16.60	7.42	2.84
4-1/2	3.640	20.00	6.71	3.55
5	4.276	19.50	9.27	3.40
5	4.214	20.50	9.00	3.67
5-1/2	4.778	21.90	11.57	3.76
5-1/2	4.670	24.70	11.05	4.28
5-9/16	4.859	22.20	11.96	3.72
6-5/8	5.965	25.20	18.03	4.21

Tank Capacity Determinations

Rectangular tanks with flat bottoms



$$\text{Volume, bbl} = \frac{\text{length, ft} \times \text{width, ft} \times \text{depth, ft}}{5.61}$$

Example 1: Determine the total capacity of a rectangular tank with flat bottom using the following data:

Length = 30 ft
Width = 10 ft
Depth = 8 ft

$$\text{Volume, bbl} = \frac{30\text{ ft} \times 10\text{ ft} \times 8\text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{2400}{5.61}$$

Volume = 427.84 bbl

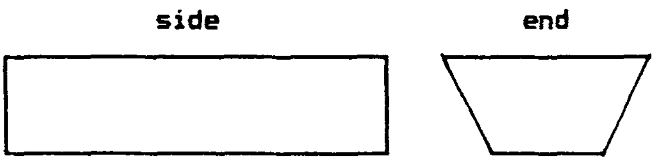
Example 2: Determine the capacity of this same tank with only 5-1/2 ft of fluid in it:

$$\text{Volume, bbl} = \frac{30\text{ ft} \times 10\text{ ft} \times 5.5\text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{1650}{5.61}$$

Volume = 294.12 bbl

Rectangular tanks with sloping sides:



$$\text{Volume, bbl} = \frac{\text{length, ft} \times [\text{depth, ft}\,(\text{width}_1 + \text{width}_2)]}{5.62}$$

Example: Determine the total tank capacity using the following data:

Length = 30 ft
Width_1 (top) = 10 ft
Width_2 (bottom) = 6 ft
Depth = 8 ft

Table A-4
DRILL COLLAR CAPACITY AND DISPLACEMENT

	I.D. Capacity	1 1/2″ .0022	1 3/4″ .0030	2″ .0039	2 1/4″ .0049	2 1/2″ .0061	2 3/4″ .0073	3″ .0087	3 1/4″ .0103	3 1/2″ .0119	3 3/4″ .0137	4″ .0155	4 1/4″ .0175
O.D.	#/ft	36.7	34.5	32.0	29.2	–	–	–	–	–	–	–	–
4″	Disp.	.0133	.0125	.0116	.0106	–	–	–	–	–	–	–	–
4 1/4″	#/ft	42.2	40.0	37.5	34.7	–	–	–	–	–	–	–	–
	Disp.	.0153	.0145	.0136	.0126	–	–	–	–	–	–	–	–
4 1/2″	#/ft	48.1	45.9	43.4	40.6	–	–	–	–	–	–	–	–
	Disp.	.0175	.0167	.0158	.0148	–	–	–	–	–	–	–	–
4 3/4″	#/ft	54.3	52.1	49.5	46.8	43.6	–	–	–	–	–	–	–
	Disp.	.0197	.0189	.0180	.0170	.0159	–	–	–	–	–	–	–
5″	#/ft	60.8	58.6	56.3	53.3	50.1	–	–	–	–	–	–	–
	Disp.	.0221	.0213	.0214	.0194	.0182	–	–	–	–	–	–	–
5 1/4″	#/ft	67.6	65.4	62.9	60.1	56.9	53.4	–	–	–	–	–	–
	Disp.	.0246	.0238	.0229	.0219	.0207	.0194	–	–	–	–	–	–
5 1/2″	#/ft	74.8	72.6	70.5	67.3	64.1	60.6	56.8	–	–	–	–	–
	Disp.	.0272	.0264	.0255	.0245	.0233	.0221	.0207	–	–	–	–	–
5 3/4″	#/ft	82.3	80.1	77.6	74.8	71.6	68.1	64.3	–	–	–	–	–
	Disp.	.0299	.0291	.0282	.0272	.0261	.2048	.0234	–	–	–	–	–
6″	#/ft	90.1	87.9	85.4	82.6	79.4	75.9	72.1	67.9	63.4	–	–	–
	Disp.	.0328	.0320	.0311	.0301	.0289	.0276	.0262	.0247	.0231	–	–	–
6 1/4″	#/ft	98.0	95.8	93.3	90.5	87.3	83.8	80.0	75.8	71.3	–	–	–
	Disp.	.0356	.0349	.0339	.0329	.0318	.0305	.0291	.0276	.0259	–	–	–

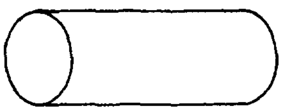
6 1/2″	#/ft	107.0	104.8	102.3	99.5	96.3	92.8	89.0	84.8	80.3	–	–	–
	Disp.	.0389	.0381	.0372	.0362	.0350	.0338	.0324	.0308	.0292	–	–	–
6 3/4″	#/ft	116.0	113.8	111.3	108.5	105.3	101.8	98.0	93.8	89.3	–	–	–
	Disp.	.0422	.0414	.0405	.0395	.0383	.0370	.0356	.0341	.0325	–		
7″	#/ft	125.0	122.8	120.3	117.5	114.3	110.8	107.0	102.8	98.3	93.4	88.3	–
	Disp.	.0455	.0447	.0438	.0427	.0416	.0403	.0389	.0374	.0358	.0340	.0321	–
7 1/4″	#/ft	134.0	131.8	129.3	126.5	123.3	119.8	116.0	111.8	107.3	102.4	97.3	
	Disp.	.0487	.0479	.0470	.0460	.0449	.0436	.0422	.0407	.0390	.0372	.0354	–
7 1/2″	#/ft	144.0	141.8	139.3	136.5	133.3	129.8	126.0	121.8	117.3	112.4	107.3	–
	Disp.	.0524	.0516	.0507	.0497	.0485	.0472	.0458	.0443	.0427	.0409	.0390	–
7 3/4″	#/ft	154.0	151.8	149.3	146.5	143.3	139.8	136.0	131.8	127.3	122.4	117.3	–
	Disp.	.0560	.0552	.0543	.0533	.0521	.0509	.0495	.0479	.0463	.0445	.0427	–
8″	#/ft	165.0	162.8	160.3	157.5	154.3	150.8	147.0	142.8	138.3	133.4	123.3	122.8
	Disp.	.0600	.0592	.0583	0.573	.0561	.0549	.0535	.0520	.0503	.0485	.0467	.0447
8 1/4″	#/ft	176.0	173.8	171.3	168.5	165.3	161.8	158.0	153.8	149.3	144.4	139.3	133.8
	Disp.	.0640	.0632	.0623	.0613	.0601	.0589	.0575	.0560	.0543	.0525	.0507	.0487
8 1/2″	#/ft	187.0	184.8	182.3	179.5	176.3	172.8	169.0	164.8	160.3	155.4	150.3	144.8
	Disp.	.0680	.06;2	.0663	0.653	.0641	.0629	.0615	.0600	.0583	.0565	.0547	.0527
8 3/4″	#/ft	199.0	106.8	194.3	191.5	188.3	194.8	181.0	176.8	172.3	167.4	162.3	156.8
	Disp.	.0724	0.716	.0707	0.697	.0685	.0672	.0658	.0613	.0697	.0609	.0590	.0570
9″	#/ft	210.2	268.0	205.6	202.7	199.6	196.0	192.2	188.0	183.5	178.7	173.5	168.0
	Disp.	.0765	.0757	.0748	0.738	.0726	.0714	.0700	.0685	.0668	.0651	.0632	.0612
10″	#/ft	260.9	258.8	256.3	253.4	250.3	246.8	242.9	238.8	234.3	229.4	224.2	118.7
	Disp.	.0950	.0942	.0933	.0923	.0911	.0898	.0884	.0869	.0853	.0835	.0816	.0796

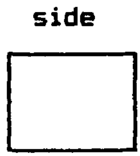
$$\text{Volume, bbl} = \frac{30\,\text{ft} \times [8\,\text{ft} \times (10\,\text{ft} + 6\,\text{ft})]}{5.62}$$

$$\text{Volume, bbl} = \frac{30\,\text{ft} \times 128}{5.62}$$

$$\text{Volume} = 683.3\,\text{bbl}$$

Circular cylindrical tanks:





$$\text{Volume, bbl} = \frac{3.14 \times r^2 \times \text{height, ft}}{5.61}$$

Example: Determine the total capacity of a cylindrical tank with the following dimensions:
Height = 15 ft
Diameter = 10 ft

NOTE: The radius (r) is one half of the diameter:

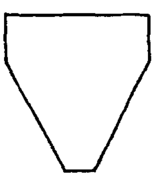
$$r = \frac{10}{2} = 5$$

$$\text{Volume, bbl} = \frac{3.14 \times 5\,\text{ft}^2 \times 15\,\text{ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{1177.5}{5.61}$$

$$\text{Volume} = 209.89\,\text{bbl}$$

Tapered cylindrical tanks:



a) Volume of cylindrical section:

$$Vc = 0.1781 \times 3.14 \times r_c^2 \times h_c$$

b) Volume of tapered section:

$$Vt = 0.059 \times 3.14 \times h_t \times (r_c^2 + r_b^2 + r_b r_c)$$

where V_c = volume of cylindrical section, bbl
r_c = radius of cylindrical section, ft
h_c = height of cylindrical section, ft
V_t = volume of tapered section, bbl
h_t = height of tapered section, ft
r_b = radius at bottom, ft

Example: Determine the total volume of a cylindrical tank with the following dimensions:

Height of cylindrical section = 5.0 ft
Radius of cylindrical section = 6.0 ft
Height of tapered section = 10.0 ft
Radius at bottom = 1.0 ft

Solution:

a) Volume of the cylindrical section:

$V_c = 0.1781 \times 3.14 \times 6.0^2 \times 5.0$
$V_c = 100.66\,\text{bbl}$

b) Volume of tapered section:

$V_t = 0.059 \times 3.14 \times 10\,\text{ft.} \times (6^2 + 1^2 + 1 \times 6)$
$V_t = 1.8526\ (36 + 1 + 6)$
$V_t = 1.8526 \times 43$
$V_t = 79.66\,\text{bbl}$

c) Total volume:

bbl = 100.66 bbl + 79.66 bbl
bbl = 180.32

Horizontal cylindrical tank:

a) Total tank capacity:

$$\text{Volume, bbl} = \frac{3.14 \times r^2 \times L\ (7.48)}{42}$$

b) Partial volume:

$$\text{Vol, ft}^3 = L\left[0.017453 \times r^2 \times \cos^{-1}\left(\frac{r-h}{r}\right) - \sqrt{2hr - h^2}(r-h)\right]$$

Example 1: Determine the total volume of the following tank:

Length = 30 ft
Radius = 4 ft

a) Total tank capacity:

$$\text{Volume, bbl} = \frac{3.14 \times 4^2 \times 30 \times 7.48}{48}$$

$$\text{Volume, bbl} = \frac{11{,}273.856}{48}$$

$$\text{Volume} = 234.87\ \text{bbl}$$

Example 2: Determine the volume if there are only 2 feet of fluid in this tank: (h = 2 ft)

$$\text{Volume, ft}^3 = 30\left[0.017453 \times 4^2 \times \cos^{-1}\left(\frac{4-2}{4}\right) - \sqrt{2 \times 2 \times 4 - 2^2} \times (4-2)\right]$$

$$\text{Volume, ft}^3 = 30\left[0.279248 \times \cos^{-1}(0.5) - \sqrt{12} \times (2)\right]$$

$$\text{Volume, ft}^3 = 30\,(0.279248 \times 60 - 3.464 \times 2)$$

$$\text{Volume, ft}^3 = 30 \times 9.827$$

$$\text{Volume} = 294\ \text{ft}^3$$

To convert volume, ft^3, to barrels, multiply by 0.1781.
To convert volume, ft^3, to gallons, multiply by 7.4805.

Therefore, 2 feet of fluid in this tank would result in:

Volume, bbl = 294 ft^3 × 0.1781
Volume = 52.36 bbl

NOTE: This is only applicable until the tank is half full (r − h). After that, calculate total volume of the tank and subtract the empty space. The empty space can be calculated by h = height of empty space.

APPENDIX B

Conversion Factors

TO CONVERT FROM	TO	MULTIPLY BY
	Area	
Square inches	Square centimeters	6.45
Square inches	Square millimeters	645.2
Square centimeters	Square inches	0.155
Square millimeters	Square inches	1.55×10^{-3}
	Circulation Rate	
Barrels/min	Gallons/min	42.0
Cubic feet/min	Cubic meters/sec	4.72×10^{-4}
Cubic feet/min	Gallons/min	7.48
Cubic feet/min	Liters/min	28.32
Cubic meters/sec	Gallons/min	15,850
Cubic meters/sec	Cubic feet/min	2118
Cubic meters/sec	Liters/min	60,000
Gallons/min	Barrels/min	0.0238
Gallons/min	Cubic feet/min	0.134
Gallons/min	Liters/min	3.79
Gallons/min	Cubic meters/sec	6.309×10^{-5}
Liters/min	Cubic meters/sec	1.667×10^{-5}
Liters/min	Cubic feet/min	0.0353
Liters/min	Gallons/min	0.264
	Impact Force	
Pounds	Dynes	4.45×10^{5}
Pounds	Kilograms	0.454
Pounds	Newtons	4.448
Dynes	Pounds	2.25×10^{-6}

TO CONVERT FROM	TO	MULTIPLY BY
Kilograms	Pounds	2.20
Newtons	Pounds	0.2248
	Length	
Feet	Meters	0.305
Inches	Millimeters	25.40
Inches	Centimeters	2.54
Centimeters	Inches	0.394
Millimeters	Inches	0.03937
Meters	Feet	3.281
	Mud Weight	
Pounds/gallon	Pounds/cu ft	7.48
Pounds/gallon	Specific gravity	0.120
Pounds/gallon	Grams/cu cm	0.1198
Grams/cu cm	Pounds/gallon	8.347
Pounds/cu ft	Pounds/gallon	0.134
Specific gravity	Pounds/gallon	8.34
	Power	
Horsepower	Horsepower (metric)	1.014
Horsepower	Kilowatts	0.746
Horsepower	Foot pounds/sec	550
Horsepower (metric)	Horsepower	0.986
Horsepower (metric)	Foot pounds/sec	542.5
Kilowatts	Horsepower	1.341
Foot pounds/sec	Horsepower	0.00181
	Presssure	
Atmospheres	Pounds/sq in.	14.696
Atmospheres	Kgs/sq cm	1.033
Atmospheres	Pascals	1.013×10^5
Kilograms/sq cm	Atmospheres	0.9678
Kilograms/sq cm	Pounds/sq in.	14.223
Kilograms/sq cm	Atmospheres	0.9678

TO CONVERT FROM	TO	MULTIPLY BY
Pounds/sq in.	Atmospheres	0.0680
Pounds/sq in.	Kgs./sq cm	0.0703
Pounds/sq in.	Pascals	6.894×10^{3}
	Velocity	
Feet/sec	Meters/sec	0.305
Feet/min	Meters/sec	5.08×10^{-3}
Meters/sec	Feet/min	196.8
Meters/sec	Feet/sec	3.28
	Volume	
Barrels	Gallons	42
Cubic centimeters	Cubic feet	3.531×10^{-5}
Cubic centimeters	Cubic inches	0.06102
Cubic centimeters	Cubic meters	10^{-6}
Cubic centimeters	Gallons	2.642×10^{-4}
Cubic centimeters	Liters	0.001
Cubic feet	Cubic centimeters	28,320
Cubic feet	Cubic inches	1728
Cubic feet	Cubic meters	0.02832
Cubic feet	Gallons	7.48
Cubic feet	Liters	28.32
Cubic inches	Cubic centimeters	16.39
Cubic inches	Cubic feet	5.787×10^{-4}
Cubic inches	Cubic meters	1.639×10^{-5}
Cubic inches	Gallons	4.329×10^{-3}
Cubic inches	Liters	0.01639
Cubic meters	Cubic centimeters	10^{6}
Cubic meters	Cubic feet	35.31
Cubic meters	Gallons	264.2
Gallons	Barrels	0.0238
Gallons	Cubic centimeters	3785
Gallons	Cubic feet	0.1337
Gallons	Cubic inches	231
Gallons	Cubic meters	3.785×10^{-3}
Gallons	Liters	3.785
	Weight	
Pounds	Tons (metric)	4.535×10^{-4}
Tons (metric)	Pounds	2205
Tons (metric)	Kilograms	1000

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Norton J. Lapeyrouse is a technical training instructor in oilfield courses with international experience. He has developed numerous training programs, courses, and manuals for supervisory and field personnel. He is currently employed by Randy Smith Training Solutions and teaches technical training courses at their Houston location.

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