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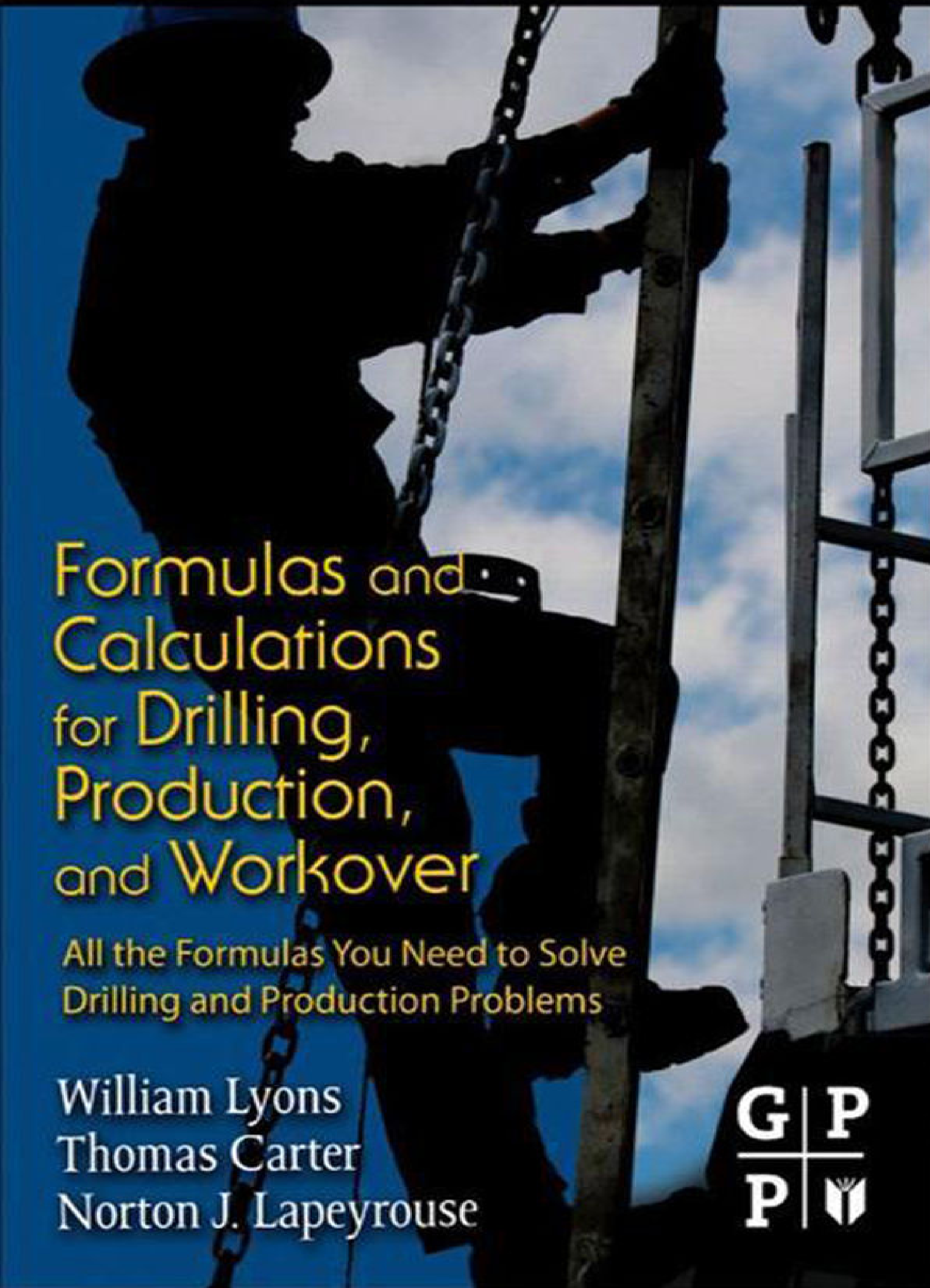

Formulas and Calculations for Drilling, Production, and Workover

All the Formulas You Need to Solve Drilling and Production Problems

William Lyons
Thomas Carter
Norton J. Lapeyrouse

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Preface

Over the past several years, hundreds of oil field personnel have told me that they have enjoyed this book. Some use it as a secondary reference source, some use it as their primary source for formulas and calculations, and some 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 this 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 mentioned a driller who carried a briefcase full of books with him each time he went to the rig floor. I also spoke of 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 oil field 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 Methods), 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 oil field 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 EQUATIONS

1.0 Terminology

The term density as used in USCS/British oil field terminology is a slang term for a value that is actually specific weight. Specific weight is in the units of lb/ft^3 or lb/gallon (ppg). Actual density in the USCS/British would be the specific weight term divided by 32.2 ft/sec^2 and would result in a USCS/British density of $slug/ft^3$. Neither the density term nor the actual density term is used in this book. This book uses the term mud weight (MW) for specific weight (lb/ft^3 or ppg). Density is used only when referring to the SI-metric values of kg/m^3, kg/liter, and $gram/cm^3$ (which are actual density values in that unit system) and for the term ECD.

1.1 Mud Weight MW (lb/ft^3), Mud Weight MW (ppg), and Specific Gravity (SG) [USCS/British]

Definition: Mud weight of fresh water MW (lb/ft^3)

$$MW_{fw} = 62.4\ lb/ft^3 \tag{1.1}$$

Example: Mud weight of fresh water MW (ppg)

$$MW_{fw} = \left(\frac{62.4}{(12)^3}\right)(231) \tag{1.2}$$

$$MW_{fw} = 8.34\ ppg$$

where: 1 gal = 231 $in.^3$
1 ft = 12 in.

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Example: Specific gravity of fresh water SG

$$SG_{fw} = \left(\frac{62.4}{62.4}\right) = 1.0 \tag{1.3}$$

or

$$SG_{fw} = \left(\frac{8.34}{8.34}\right) = 1.0 \tag{1.4}$$

Example: SG of a mud weight of 12.0 ppg

$$SG_{m} = \left(\frac{12.0}{8.34}\right) = 1.44 \tag{1.5}$$

1.2 Density ρ (kg/m³ or kg/liter), Mud Weight MW (N/m³ or N/liter), and Specific Gravity (SG) [SI-Metric]

Definition: Mud density of fresh water ρ (kg/m^3)

$$\rho_{fw} = 1000.0 \text{ kg/m}^3 \tag{1.6}$$

Example: Mud density of fresh water ρ (kg/liter)

$$\rho_{fw} = 1000.0(10^{-3})$$
$$\rho_{fw} = 1.0 \text{ kg/liter}$$

where: 1 liter = 10^{-3} m^3

Example: Mud weight of fresh water MW (N/m^3)

$$MW_{fw} = 1000.0\ g = 1000.0(9.81)$$
$$MW_{fw} = 9810.0 \text{ N/m}^3$$

where: $g = 9.81$ m/sec^2

Example: Mud weight of fresh water MW (N/liter)

$$MW_{fw} = 1.0\ g = 1.0(9.81)$$
$$MW_{fw} = 9.81 \text{ N/liter}$$

Example: Specific gravity of fresh water SG (using density)

$$SG_{fw} = \left(\frac{1000.0}{1000.0}\right) = 1.0$$

or

$$SG_{fw} = \left(\frac{1.0}{1.0}\right) = 1.0$$

Example: Specific gravity of fresh water SG (using mud weight)

$$SG_{fw} = \left(\frac{9810.0}{9810.0}\right) = 1.0$$

or

$$SG_{fw} = \left(\frac{9.81}{9.81}\right) = 1.0$$

Conversion: Mud weight of 12.0 ppg to mud weight MW (N/liter)

$$MW = 12.0(1.175) = 14.1 \text{ N/liter} \tag{1.7}$$

where: 1 ppg = 1.175 N/liter

Example: Mud weight of 14.1 N/liter to density ρ (kg/liter)

$$\rho_m = 14.1\left(\frac{1}{g}\right) = 1.44 \text{ kg/liter}$$

Example: SG of mud using density of 1.44 kg/liter

$$SG_m = \left(\frac{1.44}{1.0}\right) = 1.44$$

Example: SG of a mud with a specific weight of 14.1 N/liter

$$SG_m = \left(\frac{14.1}{9.81}\right) = 1.44$$

Table 1-1
Mud Weight and Density Conversion Factors Summary

From		To		
Density	**Mud Wt**	**Mud Wt**	**SG**	**Multiply by**
	lb/ft^3	lb/gal		0.052
	lb/ft^3		SG	(1/62.4)
	lb/gal		SG	(1/8.34)
kg/m^3		N/m^3		9.81
kg/liter		N/liter		9.81
kg/m^3		N/liter		(9.81/1000)
	N/liter		SG	(1/9.81)
	N/m^3		SG	(1/9810)

1.3 Hydrostatic Pressure (P) and (p) [USCS/British]

Definition: Hydrostatic pressure P (lb/ft^3) at a depth H (ft) below surface is

$$P\ (lb/ft^2) = MW\ (lb/ft^3)\ H\ (ft) \tag{1.8}$$

where: H (ft) is true vertical depth (TVD)

Example: Pressure (lb/ft^2) in fresh water at a depth of 1000 ft

$$P = (62.4)(1000) = 62{,}400\ lb/ft^2$$

Example: Pressure (lb/ft^2) in 12.0 ppg at a depth of 1000 ft

$$P = (89.9)(1000) = 89{,}900\ lb/ft^2$$

Definition: Hydrostatic pressure p (psi) at a depth H (ft) below surface is (using equation (1.8))

$$p\ (psi)(12)^2 = MW\ \left(lb/ft^3\right)\ H\ (ft)$$

which reduces to

$$p\ (psi) = MW\ (lb/ft^3)\left(\frac{1}{(12)^2}\right)\ H\ (ft)$$

or

$$p\ (\text{psi}) = 0.00695\ \text{MW}\ (\text{lb/ft}^3)\ \text{H}\ (\text{ft}) \tag{1.9}$$

Example: Pressure (psi) in fresh water at a depth of 1000 ft

$$p = 0.00695(62.4)(1000) = 434\ \text{psi}$$

Example: Pressure (psi) in 12.0 ppg at a depth of 1000 ft

$$P = 0.00695(89.9)(1000) = 624\ \text{psi}$$

Definition: Hydrostatic pressure p (psi) at a depth H (ft) below surface is (using equation (1.8))

$$p\ (\text{psi})(12)^2 = \text{MW}\ (\text{ppg})\left(\frac{(12)^3}{231}\right)\ \text{H}\ (\text{ft})$$

which reduces to

$$p\ (\text{psi}) = \text{MW}\ (\text{ppg})\left(\frac{12}{231}\right)\ \text{H}\ (\text{ft})$$

or

$$p\ (\text{psi}) = 0.052\ \text{MW}\ (\text{ppg})\ \text{H}\ (\text{ft}) \tag{1.10}$$

Example: Pressure (psi) in fresh water at a depth of 1000 ft

$$p = 0.052(8.34)(1000) = 434\ \text{psi}$$

Example: Pressure (psi) in 12.0 ppg mud at a depth of 1000 ft

$$p = 0.052\ (12.0)(1000) = 624\ \text{psi}$$

1.4 Hydrostatic Pressure (P) and (p) [SI-Metric]

Definition: Hydrostatic pressure P (N/m^2) at a depth H (m) below surface is (using N/m^3)

$$P\ (\text{N/m}^2) = \text{MW}\ (\text{N/m}^3)\ \text{H}\ (\text{m}) \tag{1.11}$$

Example: Pressure (N/m^2) in fresh water at a depth of 305 m (~1000 ft)

$$P = (9810)(305) = 2{,}992{,}050\ N/m^2$$

Definition: Hydrostatic pressure P (N/m^2) at a depth H (m) below surface is (using N/liter)

$$P\ (N/m^2) = 1000\ MW\ (N/liter)\ H\ (m) \tag{1.12}$$

Example: Pressure (N/m^2) in fresh water at a depth of 305 m (~1000 ft)

$$P = 1000(9.81)(305) = 2{,}992{,}050\ N/m^2$$

Definition: Hydrostatic pressure P (N/m^2) at a depth H (m) below surface is (using SG)

$$P\ (N/m^2) = SG\ MW_{fw}\ (N/m^3)\ H\ (m) \tag{1.13}$$

or

$$P\ (N/m^2) = 1000\ SG\ MW_{fw}\ (N/liter)\ H\ (m) \tag{1.14}$$

Example: Pressure (N/m^2) in fresh water at a depth of 305 m (~1000 ft)

$$P = 1000\ (1.0)(9.81)(305) = 2{,}992{,}050\ N/m^2$$

Example: Pressure (N/m^2) in mud with an SG_m of 1.44 at a depth of 305 m (~1000 ft)

$$P = 1000\ (1.44)(9.81)(305) = 4{,}308{,}552\ N/m^2$$

Definition: Hydrostatic pressure p (N/cm^2) at a depth H (m) below surface is (using SG)

$$p\ (N/cm^2) = 10^{-4}\ SG\ MW_{fw}\ (N/m^3)\ H\ (m) \tag{1.15}$$

Example: Pressure (N/cm^2) in fresh water at a depth of 305 m (~1000 ft)

$$p = 10^{-4}(1.0)(9810)(305) = 299\ \text{N/cm}^2$$

Example: Pressure (N/cm^2) in mud with an SG of 1.44 at a depth of 305 m (~1000 ft)

$$p = 10^{-4}(1.44)(9810)(305) = 431\ \text{N/cm}^2$$

NOTE: The values of p (N/cm^2) are 0.69 of the values of p (psi).

1.5 Pressure Gradient ∇ (psi/ft), G (ppg) [USCS/British]

Definition: Pressure gradient ∇ (psi/ft) is obtained from equation (1.10)

$$\nabla\ (\text{psi/ft}) = \left(\frac{p\ (\text{psi})}{H\ (\text{ft})}\right) = 0.052\ \text{MW}\ (\text{ppg}) \tag{1.16}$$

$$\nabla\ (\text{psi/ft}) = 0.052\ \text{MW}\ (\text{ppg})$$

Example: Pressure gradient ∇_{fw} (psi/ft) for fresh water

$$\nabla_{fw} = 0.052(8.34)$$
$$\nabla_{fw} = 0.434\ \text{psi/ft}$$

Example: Pressure gradient ∇_m (psi/ft) for 12.0 ppg mud

$$\nabla_m = 0.052\ (12.0)$$
$$\nabla_m = 0.624\ \text{psi/ft}$$

Definition: Pressure gradient G (ppg) is also obtained from equation (1.10)

$$G\ (\text{ppg}) = \left(\frac{p\ (\text{psi})}{0.052\ H\ (\text{ft})}\right) = \text{MW}\ (\text{ppg}) \tag{1.17}$$

$$G\ (\text{ppg}) = \text{MW}\ (\text{ppg})$$

Example: Pressure gradient G_{fw} (ppg) for fresh water

$G_{fw} = 8.34$ ppg

Example: Pressure gradient G_m (ppg) for 12.0 ppg mud

$G_m = 12.0$ ppg

1.6 Pressure Gradient G (SG) [SI-Metric]

Definition: Pressure gradient G (SG) is obtained from equation (1.12)

$$G\ (\text{N/liter}) = \left(\frac{P\ (\text{N/m}^2)}{1000\ H\ (\text{m})}\right) = MW\ (\text{N/liter}) \tag{1.18}$$

$$G\ (\text{N/liter}) = MW\ (\text{N/liter})$$

Example: Pressure gradient G_{fw} (SG) for fresh water

$G_{fw} = 1.0$

Example: Pressure gradient G_m (SG) for 12.0 ppg mud

$G_m = 1.44$

Definition: Pressure gradient G (SG) is obtained from equation (1.14)

$$G\ (\text{SG}) = \left(\frac{P\ (\text{N/m}^2)}{1000\ MW_{fw}\ (\text{N/liter})\ H\ (\text{m})}\right) = SG \tag{1.19}$$

$$\mathbf{G}\ (\text{SG}) = SG$$

Example: Pressure gradient G_{fw} (SG) for fresh water

$G_{fw} = 1.0$

Example: Pressure gradient G_m (SG) for 12.0 ppg mud

$G_m = 1.44$

Table 1-2
Pressure Gradient Conversion Factors Summary

Pressure Unit	Depth Unit	Mud Weight Unit	Factor
psi	Feet	lb/ft^3	0.00695
psi	Feet	ppg	0.052
N/m^2	Meters	N/liter	1000
N/m^2	Meters	SG	9810

1.7 Equivalent Circulating "Density" ECD (ppg) [USCS/British]

Definition: ECD takes into account the friction loss due to circulation of the drilling mud (pumps on).

$$\text{ECD (ppg)} = \left(\frac{\text{annulus friction pressure loss (psi)}}{0.052\ \text{H (ft)}}\right) + \text{MW (ppg)} \tag{1.20}$$

Example: Circulation friction pressure loss in annulus is 200 psi, MW is 9.6 ppg, and H is 10,000 ft.

$$\text{ECD} = \left(\frac{200.0}{0.052(10{,}000)}\right) + 9.6$$

$$\text{ECD} = 10.0 \text{ ppg}$$

1.8 Equivalent Circulating "Density" ECD (N/liter) and ECD (SG) [SI-Metric]

Definition: ECD takes into account the friction loss due to circulation of the drilling mud (pumps on).

$$\text{ECD (N/liter)} = \left(\frac{\text{annulus friction pressure loss (N/m}^2\text{)}}{1000\ \text{H (m)}}\right) + \text{MW (N/liter)} \tag{1.21}$$

Example: Circulation friction pressure loss in annulus is 1,380,000 N/m^2, MW is 11.3 N/liter, and H is 3048 m. Note pressure can also be written as 1.38 M Pa (where $M = 10^6$, $Pa = N/m^2$).

$$\text{ECD} = \left(\frac{1{,}380{,}000}{1000(10{,}000)}\right) + 11.3$$
$$\text{ECD} = 11.8 \text{ N/liter}$$

Definition: ECD takes into account the friction loss due to circulation of the drilling mud (pumps on).

$$\text{ECD (SG)} = \left(\frac{\text{annulus friction pressure loss } (N/m^2)}{9810\,H\,(m)}\right) + \text{MW (SG)} \tag{1.22}$$

Example: Circulation friction pressure loss in annulus is 1,380,000 N/m^2, mud SG is 1.15, and H is 3048 m.

$$\text{ECD} = \left(\frac{1{,}380{,}000}{9810(3048)}\right) + 1.15$$
$$\text{ECD} = 1.20$$

1.9 Mud Pump Output Q (bbl/stk) and q (gpm) [USCS/British]

1.9.1 Triplex Pump

Formula 1

$$Q\ (\text{gal/stk}) = 0.0102\ D_l^2 S\, e_v \tag{1.23}$$

where: D_l = liner diameter (in.)
S = stroke length (in.)
e_v = volumetric efficiency

Example: Q (gal/stk) at 100% volumetric efficiency for a 7 in. by 12 in. triplex pump

$$Q = 0.0102\ (7.0)^2(12)(1.0)$$
$$Q = 6.0 \text{ gal/stk}$$

The above assumes 100% volumetric efficiency of the pump. **NOTE:** Most published information on pump output per stroke assumes 100% volumetric efficiency. The pump manufacturers can be contacted to get actual pump volumetric efficiencies. These efficiencies can vary from 0.85 to 0.98. Published data can be checked by assuming $e_v = 1.0$.

Example: Adjust the above result for a pump with a volumetric efficiency of 0.90.

$$Q_{actual} = 6.0(0.90) = 5.4 \text{ gal/stk}$$

Formula 2

$$q\ (\text{gpm}) = 0.0102\ D_l^2\ S\, N\, e_v \tag{1.24}$$

where: D_l = liner diameter (in.)
S = stroke length (in.)
N = strokes per minute (also rpm of pump flywheel)
e_v = volumetric efficiency

Example: Determine the pump output q (gpm) at 100% volumetric efficiency, for a 7 in. by 12 in. triplex pump at 80 SPM.

$$q\ (\text{gpm}) = 0.0102\ (7)^2(12)(80)(1.0)$$
$$q = 480 \text{ gpm}$$

1.9.2 Duplex Pump

Formula 1

$$Q\ (\text{gal/stk}) = 0.0068(2\ D_l^2 - D_r^2) S\, e_v \tag{1.25}$$

where: D_l = liner diameter (in.)
D_r = rod diameter (in.)
S = stroke length (in.)
e_v = volumetric efficiency

Example: Determine the output q (bbl/stk) of a 5½ in. by 14 in. duplex pump at 100% efficiency. Pump has a rod diameter = 2.0 in.

$$Q = 0.0068\,[2(5.5)^2 - (2.0)^2](14)(1.0)$$
$$Q = 5.38 \text{ gal/stk}$$

Example: Adjust the above result for a pump with a volumetric efficiency of 0.88.

$$Q_{actual} = 5.38\,(0.88) = 4.74 \text{ gal/stk}$$

Formula 2

$$q\,(\text{gpm}) = 0.0068\,\left[2\,D_l^{\,2} - D_r^{\,2}\right] S\,N\,e_v \tag{1.26}$$

where: D_l = liner diameter (in.)
D_r = rod diameter (in.)
S = stroke length (in.)
e_v = volumetric efficiency

Example: Determine the output q (gpm) of a 5½ in. by 14 in. duplex pump at 100% efficiency. Pump has a rod diameter = 2.0 in. N is 50 spm.

$$q = 0.0068\,[2(5.5)2 - (2)2](14)(50)(1.0)$$
$$q = 269 \text{ gpm}$$

1.9.3 Hydraulic Horsepower

$$HP = \left(\frac{p\,q}{1714}\right) \tag{1.27}$$

where: p = gauge pressure (psi)
q = volumetric flow (gpm)

$$HP_{input} = \left(\frac{p\,q}{1714\,e_v\,e_m}\right) \tag{1.28}$$

where: e_v = volumetric efficiency (~0.85 to 0.98)
e_m = mechanical efficiency (~0.80 for continuous operations and ~0.9 for intermittent operations)

Example: Determine the hydraulic horsepower of a pump that has a volumetric output of 480 gpm at a pressure of 1800 psig.

$$HP = \left(\frac{(1800)(480)}{1714}\right)$$

$$HP = 504$$

This represents the horsepower that the pump must apply to move the drilling mud within the pump.

Example: Determine the input horsepower that must be applied to the pumping unit by a prime mover to pump the drilling mud in the above example with continuous operations ($e_m \sim 0.80$) and the pump has a volumetric efficiency of 0.96.

$$HP_{input} = \left(\frac{(1800)(480)}{1714(0.96)(0.80)}\right)$$

$$HP_{input} = 656$$

1.10 Capacity Formulas

1.10.1 Annular Capacity between Casing or Hole and Drill Pipe, Tubing, or Casing

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

Example: Hole size (Dh) = 12¼ 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) $\text{Annular capacity, ft/bbl} = \dfrac{1029.4}{(\text{Dh}^2 - \text{Dp}^2)}$

Example: Hole size (Dh) = 12¼ in.
Drill pipe OD (Dp) = 5.0 in.

$$\text{Annular capacity, tt/bbl} = \frac{1029.4}{(12.25^2 - 5.0^2)}$$
$$\text{Annular capacity} = 8.23\ \text{ft/bbl}$$

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

Example: Hole size (Dh) = 12¼ in.
Drill pipe OD (Dp) = 5.0 in.

$$\text{Annular capacity, gal/ft} = \frac{(12.25^2 - 5.0^2)}{24.51}$$
$$\text{Annular capacity} = 5.1\ \text{gal/ft}$$

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

Example: Hole size (Dh) = 12¼ in.
Drill pipe OD (Dp) = 5.0 in.

$$\text{Annular capacity, ft/gal} = \frac{24.51}{(12.25^2 - 5.0^2)}$$
$$\text{Annular capacity} = 0.19598\ \text{ft/gal}$$

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

Example: Hole size (Dh) = 12¼ in.
Drill pipe OD (Dp) = 5.0 in.

$$\text{Annular capacity, ft}^3\text{/lin ft} = \frac{(12.25^2 - 5.0^2)}{183.35}$$
$$\text{Annular capacity} = 0.682097\ \text{ft}^3\text{/lin ft}$$

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

Example: Hole size (Dh) = 12¼ in.
Drill pipe OD (Dp) = 5.0 in.

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

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

1.10.2 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.
T1 = tubing No. 1—2 in. OD = 2.375 in.
T2 = tubing No. 2—2 in. OD = 2.375 in.

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

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

$$\text{Annular capacity, bbl/ft} = 0.026\,19 \text{ bbl/ft}$$

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.
T1 = tubing No. 1—2 in. OD = 2.375 in.
T2 = tubing No. 2—2 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 strings of tubing of same size

Dh = casing—7.0 in., 29 lb/ft ID = 6.184 in.
T1 = tubing No. 1—2 in. OD = 2.375 in.
T2 = tubing No. 2—3½ in. OD = 3.5 in.

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

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

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 strings of tubing of same size

Dh = casing—7.0 in., 29 lb/ft ID = 6.184 in.
T1 = tubing No. 1—2 in. OD = 2.375 in.
T2 = tubing No. 2—3½ in. OD = 3.5 in.

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

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

e) Annular capacity between casing and multiple strings of tubing, ft³/lin ft

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

Example: Using three strings of tubing

Dh = casing—9 in., 47 1b/ft	ID = 8.681 in.
T_1 = tubing No. 1—3½ in.	OD = 3.5 in.
T_2 = tubing No. 2—3½ in.	OD = 3.5 in.
T_3 = tubing No. 3—3½ in.	OD = 3.5 in.

$$\text{Annular capacity, ft}^3\text{/lin ft} = \frac{8.681^2 - (3.5^2 + 3.5^2 + 3.5^2)}{183.35}$$

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

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

f) Annular capacity between casing and multiple strings of tubing, lin ft/ft³

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

Example: Using three strings of tubing

Dh = casing—9 in., 47 1b/ft	ID = 8.681 in.
T_1 = tubing No. 1—3½ in.	OD = 3.5 in.
T_2 = tubing No. 2—3½ in.	OD = 3.5 in.
T_3 = tubing No. 3—3½ in.	OD = 3.5 in.

$$\text{Annular capacity, lin ft/ft}^3 = \frac{183.35}{8.681^2 - (3.5^2 + 3.5^2 + 3.5^2)}$$

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

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

1.10.3 Capacity of Tubulars and Open Hole: Drill Pipe, Drill Collars, Tubing, Casing, Hole, and Any Cylindrical Object

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

Example: Determine the capacity, bbl/ft, of a 12¼ 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 a 12¼ in. hole.

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

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

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

Example: Determine the capacity, gal/ft, of an 8½ in. hole.

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

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

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

Example: Determine the capacity, ft/gal, of an 8½ in. hole.

$$\text{Capacity, ft/gal} = \frac{24.51}{8.5^2}$$
$$\text{Capacity} = 0.3392 \text{ ft/gal}$$

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

Example: Determine the capacity, ft/lin ft, for a 6.0 in. hole.

$$\text{Capacity, ft}^3\text{/lin ft} = \frac{6.0^2}{183.35}$$
$$\text{Capacity} = 0.1963 \text{ ft}^3\text{/lin ft}$$

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

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

$$\text{Capacity, lin ft/ft}^3 = \frac{183.35}{6.0^2}$$
$$\text{Capacity} = 5.093051 \text{ in. ft/ft}^3$$

1.10.4 Amount of Cuttings Drilled per Foot of Hole Drilled

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

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

Example: Determine the number of barrels of cuttings drilled for 1 ft of 12¼ 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 1 ft of 12¼ 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, lb
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 12¼ in. hole (0.1458 bbl/ft). Specific gravity of cuttings = 2.40 gm/cc. Porosity = 20%.

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

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

1.11 Annular Velocity V_{an} (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 bbl/min ÷ 0.1261 bbl/ft
AV = 99.92 ft/min

Formula 2

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

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

Example: Q = 530 gpm
Dh = 12¼ in.
Dp = 4½ in.

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

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

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

Formula 3

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

Example: pump output = 12.6 bbl/min
hole size = 12¼ in. pipe
OD = 4½ in.

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

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

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

Annular velocity (AV), ft/sec

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

Example: pump output = 12.6 bbl/min
hole size = 12¼ in.
pipe OD = 4½ in.

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

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

$$AV = 1.6656 \text{ ft/sec}$$

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

SI Unit 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

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

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 = 12¼ in.
pipe OD = 4½ in.

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

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

$$PO = \frac{15577.5}{24.5}$$

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

1.12 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 = 12¼ in.
Dp = 4½ in.
pump output = 0.136 bbl/stk

$$SPM = \frac{120 \text{ ft/min} \times 0.126 \text{ bbl/ft}}{0.136 \text{ bbl/stk}}$$

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

$$SPM = 111.3$$

1.13 Control Drilling

Maximum drilling rate (MDR), ft/hr, when drilling large diameter holes (14¾ in. and larger)

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

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 = 17½ in.

$$\text{MDR, ft/hr} = \frac{67 \times (9.7 - 9.0) \times 350}{17.5^2}$$

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

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

1.14 Buoyancy Factor (BF)

Buoyancy factor (BF) using mud weight, ppg

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

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

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

$$\text{BF} = 0.77099$$

Buoyancy factor using mud weight, lb/ft^3

$$BF = \frac{489 - MW, lb/ft^3}{489}$$

Example: Determine the buoyancy factor for a 120 lb/ft^3 fluid.

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

$$BF = 0.7546$$

1.15 Decrease When Pulling Pipe Out of the Hole

1.15.1 When Pulling DRY Pipe

Step l

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

Step 2

$$\begin{array}{l}\text{HP, psi}\\ \text{decrease}\end{array} = \frac{\text{barrel displaced}}{\begin{array}{c}\text{casing}\\ \text{capacity,}\\ \text{bbl/ft}\end{array} - \begin{array}{c}\text{pipe}\\ \text{displacement}\\ \text{bbl/ft}\end{array}} \times 0.052 \times MW, ppg$$

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

Barrels displaced = 5 stands × 92 ft/std × 0.0075 bbl/ft
Barrels displaced = 3.45

Step 2

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

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

1.15.2 When Pulling WET Pipe

Step l

$$\text{Barrels displaced} = \begin{matrix}\text{number}\\ \text{of stands}\\ \text{pulled}\end{matrix} \times \begin{matrix}\text{average}\\ \text{length per}\\ \text{stand, ft}\end{matrix} \times \left(\begin{matrix}\text{pipe displacement,}\\ \text{bbl/ft} + \text{pipe}\\ \text{capacity, bbl/ft}\end{matrix}\right)$$

Step 2

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

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 l

Barrels displaced = 5 stands × 92 ft/std × (0.0075 bbl/ft + 0.01776 bbl/ft)
Barrels displaced = 11.6196

Step 2

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

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

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

1.16 Loss of Overbalance Due to Falling Mud Level

1.16.1 Feet of Pipe Pulled DRY to Lost Overbalance

$$\text{Feet} = \frac{\text{overbalance, psi(casing capacity} - \text{pipe displacement, bbl/ft)}}{\text{mud weight, ppg} \times 0.052 \times \text{pipe displacement, bbl/ft}}$$

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

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

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

$$\text{Feet} = 2334$$

1.16.2 Feet of Pipe Pulled WET to Lose Overbalance

$$\text{Feet} = \frac{\text{overbalance, psi} \times (\text{casing capacity} - \text{pipe capacity} - \text{displacement, bbl/ft})}{\text{MW, ppg} \times 0.052 \times (\text{pipe capacity} + \text{pipe displacement, bbl/ft})}$$

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

$$\text{Feet} = \frac{150 \text{ psi} \times (0.0773 - 0.01776 - 0.0075 \text{ bbl/ft})}{11.5 \text{ ppg} \times 0.052(0.01776 + 0.0075 \text{ bbl/ft})}$$

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

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

$$\text{Feet} = 516.8$$

Metric Calculations

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

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

$$\text{pressure drop per meter tripping WET pipe, bar/m} = \frac{\text{drilling fluid density, kg/l} \times \left(\text{metal displacement, l/m} + \text{pipe capacity, l/m}\right) \times 0.0981}{\text{annular capacity, l/m}}$$

$$\text{pressure drop per meter tripping WET pipe, bar/m} = \frac{\text{drilling fluid density, bar/m} \times \left(\text{metal displacement, l/m} + \text{pipe capacity, l/m}\right)}{\text{annular capacity, l/m}}$$

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

SI Unit Calculations

$$\text{pressure drop per meter tripping DRY pipe, kPa/m} = \frac{\text{drilling fluid density, kg/m}^3 \times \text{metal displacement, m}^3\text{/m}}{\text{casing capacity, m}^3\text{/m} - \text{metal displacement, m}^3\text{/m} \times 102}$$

$$\text{pressure drop per meter tripping WET pipe, kPa/m} = \frac{\text{drilling fluid density, kg/m}^3 \times \left(\text{metal displacement, m}^3\text{/m} + \text{pipe capacity, m}^3\text{/m}\right)}{\text{annular capacity, m}^3\text{/m} \times 102}$$

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

Formation Temperature (T_f)

$$T_f, {}^\circ F = (\text{ambient surface temperature, } {}^\circ F) + (\text{temperature increase } {}^\circ F \text{ per ft of depth} \times \text{TVD, ft})$$

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.

$$T_f, {}^\circ F = 70^\circ F + (0.012^\circ F/ft \times 15{,}000\ ft)$$

$$T_f, {}^\circ F = 70^\circ F + 180^\circ F$$

$$T_f = 250^\circ F \text{ (estimated formation temperature)}$$

1.17 Circulating 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

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

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

$$\text{HHP} = 894.98$$

a) Drill pipe/drill collar calculations

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

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

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

$$\text{Weight, lb/ft} = \text{displacement, bbl/ft} \times 2747 \text{ lb/bbl}$$

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 = $2\tfrac{13}{16}$ in.

Convert $\tfrac{13}{16}$ to decimal equivalent: $13 \div 16 = 0.8125$

b) $$\text{Capacity, bbl/ft} = \frac{2.8125^2}{1029.4}$$

$$\text{Capacity} = 0.007684 \text{ bbl/ft}$$

c) $$\text{Displacement, bbl/ft} = \frac{8.0^2 - 2.8125^2}{1029.4}$$

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

$$\text{Displacement} = 0.0544879 \text{ bbl/ft}$$

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

1.17.1 Rule of Thumb Formulas

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

$$\text{Weight, lb/ft} = (\text{OD, in.}^2 - \text{ID, in.}^2)2.66$$

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.

$$\text{Weight, lb/ft} = (\text{OD, in.}^2 - \text{ID, in.}^2)2.56$$

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

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

Basic Formula

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

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

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

$$\text{Factor} = \frac{\log(5.555556)}{\log(2.625)}$$

$$\text{Factor} = 1.7768$$

Example: Same example as above but with correct factor.

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

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

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

Metric Calculation

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

SI Unit Calculation

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

1.19 Cost per Foot

$$C_f = \frac{B + C_r(R_t + T_{rt})}{F}$$

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

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

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

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

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

1.20 Temperature Conversion Formulas

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

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

Example: Convert 95 °F to °C.

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

$$°C = 35 \qquad\qquad °C = 35$$

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

Nomenclature for Equations

Symbol	Description	Units
A_{bcs}	area below the casing shoe	sq. in.
A_s	cross-sectional area of the pipe wall	sq. in.
BF	buoyancy factor	dimensionless
C_{bp}	strokes to bump the plug	stk
C_{ca}	cycles or strokes for casing/drill pipe annulus	stk
C_{csfp}	strokes required to chase the spotting fluid	stk
C_{dca}	cycles or strokes for open hole/drill collar annulus	stk
C_{dcmt}	strokes required to displace the cement	stk
C_{dpa}	cycles or strokes for open hole/drill pipe annulus	stk
C_{ds}	cycles or strokes for inside the drill string	stk
C_{hwdpa}	cycles or strokes for open hole/heavy weight drill pipe annulus	stk
C_r	strokes required for the pump pressure to increase	stk
C_{ra}	cycles or strokes for riser/drill pipe annulus	stk
C_s	number of pump cycles or strokes for entire system	stk
C_{sfp}	strokes to pump spotting fluid pill	bbl/stk
C_{sfpt}	total strokes to spot the pill	stk
C_{ss}	strokes required to pump spotting fluid through surface system	stk
D	depth of hole	ft
D_1	density of item 1 in consistent units	lbm/gal, lb/ft^3
D_2	density of item 2 in consistent units	lbm/gal, lb/ft^3
D_{bit}	diameter of bit	inches
D_h	hole diameter	inches
D_{hwo}	diameter of “washout” hole	inches
D_i	inside diameter (ID) of drill pipe, HWDP, drill collars, or casing	inches
D_p	outside diameter (OD) of drill pipe, HWDP, or casing	inches
D_{pwo1}	depth of pipe washout	ft
D_{pwo2}	depth of pipe washout	ft
D_{tcmt}	depth of the top of the cement slurry in the annulus	ft
D_{TV}	total vertical depth	ft
DL_{CO}	drill line cutoff	ft
DP	differential pressure between the cement and the mud	psi
f_2	safety factor to correct new drill pipe to no. 2 pipe	
F_d	differential force	lb

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Symbol	Description	Units
f_{dc}	safety factor to place neutral point in drill collars	
F_{down}	downward force or weight of the casing	lb
F_p	pull force	1000 lb
F_{pd}	differential pull force	lb
F_{up}	upward force on casing	lb
G_{sfp}	difference in pressure gradient	psi/ft
H_{cmt}	height of cement slurry in the annulus	ft
HP_{cmt}	pressure exerted by the cement	psi
HP_{csg}	total pressure inside the casing	psi
HP_L	hydrostatic pressure of LEAD cement	psi
HP_m	pressure exerted by the mud	psi
HP_{ma}	hydrostatic pressure of mud in annulus	psi
HP_T	hydrostatic pressure of TAIL cement	psi
HP_{ta}	total hydrostatic pressure in annulus	psi
H_{wo}	hole "washout" factor	percent
K_{fpc}	calculated free point constant	
K_{fpt}	free point constant from Table 2-2	
L_{as}	length of distance between cementing tool and casing shoe	ft
L_{bha}	length of BHA necessary for a desired WOB	ft
L_{cmt}	length of section to be cemented	ft
L_{csg}	length of the casing	ft
L_{css}	length of one joint of casing	ft
L_{ds}	length of drill string	ft
L_f	length of fluid added to the top of the annulus	ft
L_{fc}	length of casing from the surface to the float collar	ft
L_{max}	maximum length of drill pipe that can be run into the hole with a specific BHA	ft
L_p	length of drill pipe, HWDP, drill collars, open hole or casing	ft
L_{pd}	length of dry pipe	ft
L_{plug}	length of plug	ft
L_{ps}	length of one stand of drill pipe (average)	ft
L_s	length of drill pipe, HWDP, or drill collar section	ft
L_{sfp}	length of unweighted spotting fluid pill	ft
L_{sfpa}	length of spotting fluid pill in annulus	ft
MOP	margin of overpull	lb
OB	overbalance pressure needed to control pore pressure	psi
O_p	pump output	bbl/stk
P	pressure (Boyle's equation)	psi
P_b	pressure to balance forces	psi
P_{bc}	actual pressure required to break circulation in the well	psi
P_{BHP}	decrease in bottom hole pressure	psi
P_d	differential pressure	psi
P_{dps}	pipe stretch (calculated or obtained from Table 2-2)	inches

Symbol	Description	Units
P_e	final or ending accumulator pressure	psi
P_f	minimum pressure after activation	psi
P_{f1}	length of free pipe	ft
P_{f2}	length of free pipe	ft
PG_d	difference in the pressure gradient between the cement and the mud	psi/ft
P_{gsa}	pressure required to break gel strength in the annulus	psi
P_{gsds}	pressure required to break gel strength inside the drill string	psi
P_{gst}	pressure required to break circulation in the well	psi
P_m	maximum system pressure	psi
P_p	precharge pressure	psi
P_s	starting accumulator pressure	psi
RT_{TM}	round trip in ton-miles	ton-miles
SG_a	specific gravity of dry additive	gm/cm^3
SG_c	specific gravity (average bulk density) of cuttings	gm/cm^3
SG_{cmt}	specific gravity of dry cement	gm/cm^3
S_{ha}	height of the slug in the annulus	ft
S_{HP}	slug hydrostatic pressure	psi
S_l	slug length	ft
S_{ldp}	length of dry pipe after pumping the slug	ft
S_{pg}	slug pressure gradient	psi/ft
S_{pit}	volume increase in mud pit	bbl
SR_{cmt}	cement required for plug	sks
SR_L	cement required for LEAD job	sk
SR_{plug}	cement required for a given length of plug	sks
SR_{Ta}	cement required in annulus for the TAIL job	sk
SR_{Tc}	cement required inside the casing for the TAIL job	sk
S_v	volume of slug	bbl
S_{vg}	volume gained due to pumping slug	bbl
S_w	slug weight	lbm/gal
T_5	ton-miles for one round trip at the shallower depth, the depth that the bit is pulled up to	ton-miles
T_6	ton-miles for one round trip at the deeper depth, the depth of the bit before starting the short trip	ton-miles
TM_1	ton-miles for one round trip—depth where drilling started	ton-miles
TM_2	ton-miles for one round trip—depth where drilling stopped before coming out of the hole	ton-miles
TM_3	ton-miles for one round trip—depth where coring started	ton-miles
TM_4	ton-miles for one round trip—depth where coring stopped before coming out of the hole	ton-miles
TM_5	ton-miles for one round trip at bit depth before short trip	ton-miles

Symbol	Description	Units
TM_6	ton-miles for one round trip from the depth at the end of a short trip	ton-miles
TM_C	ton-miles while coring	ton-miles
TM_{CSG}	ton-miles setting casing	
TM_D	drilling or "connection" in ton-miles	ton-miles
TM_{ST}	ton-miles for short trip	ton-miles
TS	tensile strength for new drill pipe	lb
T_t	total circulation time	minutes
V	volume (Boyle's equation)	gal
$V_{\%e}$	excess volume for job	%
V_1	volume of item 1 in consistent units	gal/bbl/ft^3
V_2	volume of item 2 in consistent units	gal/bbl/ft^3
V_a	annular volume	bbl
$V_{a\%}$	volume percent of additive for cement mixture	%
V_{ac}	volume of the open hole and drill pipe or casing	ft/bbl
V_{acb}	capacity of the annulus between the open hole or casing	bbl/ft
V_{acf}	annular capacity	ft^3/ft
V_{at}	total volume of annulus	bbl
V_{aw}	volume of water required for additive portion	gal/sk
V_b	volume capacity of bottle	gal
V_{ca}	volume of intermediate casing annulus	bbl
V_{cc}	casing capacity	ft^3/ft
V_{cc}	volume of cement left in casing	ft^3
V_{cs}	volume of cement slurry	gal/sk
V_{cs}	volume of cement slurry	ft^3
V_{csfp}	volume required to chase the spotting fluid	bbl
V_{cw}	volume of water required for cement portion	gal/sk
V_{cwt}	total volume of water required for each sack of cement	gal/sk
V_{cwt}	water requirement of cement	gal/sx
V_d	dead hydraulic volume per bottle	gal
V_{dc}	volume of drill collars	bbl
V_{dcmt}	volume of mud required to displace cement slurry	bbl
$V_{displace}$	volume of fluid required to spot the plug	bbl
V_{dp}	volume of drill pipe	bbl
V_{cdp}	capacity of drill pipe	bbl/ft
V_{ds}	volume of drill string	bbl
V_f	volume of fluid added to the top of the annulus	bbl
V_{fc}	casing capacity down to the float collar	bbl
V_h	volume of open hole	bbl/1000 ft
V_{hdc}	volume of drill collars	bbl
V_{hdp}	volume of open hole/drill pipe annulus	bbl
V_{hhwdp}	volume of open hole/heavy weight drill pipe annulus	bbl

Symbol	Description	Units
V_{hm}	volume of open hole	m^3/km or l/m
V_{hwdp}	volume of heavy weight drill pipe	bbl
V_p	volume of drill pipe, HWDP, drill collars, or casing	bbl
V_{pc}	drill pipe, HWDP, drill collar, or casing capacity	bbl/ft
V_r	volume of hydraulic fluid removed	gal
V_{ra}	volume of riser annulus	bbl
V_s	total volume of drill string or system	bbl
V_{sfpa}	volume of spotting fluid pill in the annulus	bbl
V_{sfpds}	predetermined volume of spotting fluid pill to be left inside drill string	bbl
V_{sfpds}	volume of spotting fluid pill left in drill string	bbl
V_{sfpt}	total volume of spotting fluid pill required	bbl
$V_{spacer\ ahead}$	volume of spacer pumped ahead of cement plug	bbl
$V_{spacer\ behind}$	volume of spacer pumped behind cement plug	bbl
V_{tb}	total hydraulic volume per bottle	gal
V_t	total accumulator volume	gal
V_u	useable volume per bottle	gal
V_{wa}	water requirement of additive	gal/sx
W_b	weight of traveling block assembly	lb
W_{bdc}	buoyed weight of drill collars in mud minus the buoyed weight of the same length of drill pipe	lb
W_{bdp}	buoyed weight of drill pipe	lb/ft
W_{ben}	weight of bentonite required	lb
W_{bha}	weight of the BHA	lb
W_{bit}	desired weight on bit (WOB)	lb
W_{ca}	weight of cement additive	lb
W_{cam}	weight of cement additive materials	lb/sk
W_{cs}	weight of cement slurry	lbm/gal
W_{csgb}	buoyed weight of casing	lb/ft
W_{csg}	weight of casing	lb/ft
W_{dc}	weight of drill collar	lb/ft
W_{dp}	weight of drill pipe with tool joints	lb/ft
W_{dpt}	weight of drill pipe tube (excluding tool joints)	lb/ft
W_f	weight of fluid added to the top of the annulus	lbm/gal
W_m	mud weight	lbm/gal
W_{ma}	weight of mud in annulus	lbm/gal
W_{mb}	mud weight increase required to balance pressure	lbm/gal
W_{me}	equivalent mud weight	lbm/gal
W_{mn}	new mud weight to balance pressure	lbm/gal
W_{mw}	total weight of mixing water	lb
W_r	resulting weight with cuttings plus water	lbm/gal
W_s	weight of steel	lbm/gal
W_{sfp}	weight of spotting fluid pill	lbm/gal
W_{tb}	weight of traveling block or top drive assembly	lb
Y_{cs}	yield of cement slurry	ft^3/sk

Symbol	Description	Units
Y_L	yield of LEAD cement in	ft^3/sk
Y_T	yield of TAIL cement in	ft^3/sk
τ_{egs}	effective gel strength based on pressure required to break circulation	$lb/100\ ft^2$
τ_{gs}	10 min gel strength of drilling fluid	$lb/100\ ft^2$

2.0 Capacity, Volumes, and Strokes

2.0.1 Capacity of Drill Pipe, HWDP, Casing, or Open Hole in bbl/ft

$$V_{pc} = \left(\frac{D_i^{\,2}}{1029.4}\right) \tag{2.1}$$

Where: V_{pc} = drill pipe, HWDP, drill collar, casing, or open hole capacity in bbl/f
D_i = inside diameter (ID) of drill pipe, HWDP, drill collars, casing, or open hole in inches

2.0.2 Capacity of Casing or Open Hole between Drill Pipe, HWDP, or Casing in bbl/ft

$$V_{ac} = \left(\frac{D_h^{\,2} - D_p^{\,2}}{1029.4}\right) \tag{2.2}$$

Where: V_{ac} = annular capacity in bbl/ft
D_h = inside diameter of casing or open hole in inches
D_p = outside diameter (OD) of drill pipe, HWDP, or casing in inches

2.0.3 Capacity of Drill Pipe, HWDP, Casing, or Open Hole in ft/bbl

$$V_{pcf} = \left(\frac{1029.4}{D_i^{\,2}}\right) \tag{2.3}$$

Where: V_{pcf} = capacity of drill pipe, HWDP, drill collars, casing, or open hole in ft/bbl

2.0.4 Capacity of Casing or Open Hole between Drill Pipe, HWDP, or Casing in ft/bbl

$$V_{acf} = \left(\frac{1029.4}{D_h^2 - D_p^2}\right) \tag{2.4}$$

Where: V_{acf} = annular capacity in ft/bbl

2.0.5 Volume of Drill Pipe, HWDP, Drill Collar, or Casing in bbl

$$V_p = \left(\frac{D_i^2}{1029.4}\right)(L_p) \tag{2.5}$$

Where: V_p = volume of drill pipe, HWDP, drill collars, or casing in bbl
L_p = length of drill pipe, HWDP, drill collars, or casing in ft

2.0.6 Volume between Drill Pipe, HWDP, or Casing, and the Casing or Open Hole in bbl

$$V_a = \left(\frac{D_h^2 - D_p^2}{1029.4}\right)(L_p) \tag{2.6}$$

Where: V_a = annular volume in bbl
L_p = length of drill pipe, HWDP, drill collars, open hole, or casing in ft

⇨Rule of Thumb: Hole Volume

$$V_h = D_h^2 \tag{2.7}$$

Where: V_h = volume of open hole in bbl/1000 ft
D_h = hole diameter in inches

NOTE: Results are 2.9% higher than amount calculated with equation (2.1).

$$V_{hm} = \left(\frac{D_h{}^2}{2}\right) \tag{2.8}$$

Where: V_{hm} = volume of open hole in m^3/km or l/m

NOTE: Results are 1.3% lower than amount calculated with equation (2.1).

Example: Determine volumes and strokes for the following:

Riser/Casing/Open Hole

Item	Size, Inches	Weight per Foot	Length, Feet
Riser	18¾ (ID)		5075
Intermediate Casing	13⅝ × 12¼	88.2	8425
Open Hole	9⅞		4000

Drill String

Item	Size, Inches	Weight per Foot, lb	Length, Feet
DP	6⅝ × 5.965	25.2	15,900
HWDP	6⅝ × 4½	63.2	1000
DC	8½ × 2¹³⁄₁₆	172	600

Pumps

Item	Size, Inches	Efficiency, %	Output, bbl/stk	SPM
Hole Pumps	5½ × 14	97	0.100	210
Booster Pump	6 × 6	97	0.051	180

Step 1: Calculate the drill string volume:

a) Drill pipe volume:

$$V_{dp} = \left(\frac{5.965^2}{1029.4}\right)(15{,}900) = (0.03457)(15{,}900) = 549.6 \text{ bbl}$$

Where: V_{dp} = volume of drill pipe in bbl

b) Heavy weight drill pipe volume:

$$V_{hwdp} = \left(\frac{4.5^2}{1029.4}\right)(1000) = (0.01967)(1000) = 19.7\,\text{bbl}$$

Where: V_{hwdp} = volume of heavy weight drill pipe in bbl

c) Drill collars volume:

$$V_{dc} = \left(\frac{2.8125^2}{1029.4}\right)(600) = (0.00768)(600) = 4.6\text{ bbl}$$

Where: V_{dc} = volume of drill collars in bbl

d) Total drill string volume:

$$V_s = 549.6 + 19.7 + 4.6 = 573.9\text{ bbl}$$

Where: V_s = total volume of drill string in bbl

Step 2: Calculate the annular volume:

a) Drill pipe/riser annular volume:

$$V_{ra} = \left(\frac{18.75^2 - 6.625^2}{1029.4}\right)(5075) = (0.29888)(5075) = 1516.8\,\text{bbl}$$

Where: V_{ra} = volume of riser annulus in bbl

b) Drill pipe/casing annular volume:

$$V_{ca} = \left(\frac{12.25^2 - 6.625^2}{1029.4}\right)(8425) = (0.10314)(8425) = 869.0\,\text{bbl}$$

Where: V_{ca} = volume of intermediate casing annulus in bbl

c) Open hole/drill pipe annular volume:

$$V_{hdp} = \left(\frac{9.875^2 - 6.625^2}{1029.4}\right)(2400) = (0.05209)(2400) = 125.0\,\text{bbl}$$

Where: V_{hdp} = volume of open hole/drill pipe annulus in bbl

d) Open hole/heavy weight drill pipe annular volume:

$$V_{hhwdp} = \left(\frac{9.875^2 - 6.625^2}{1029.4}\right)(1000) = (0.05209)(1000) = 52.1 \text{ bbl}$$

Where: V_{hhwdp} = volume of open hole/heavy weight drill pipe annulus in bbl

e) Open hole/drill collars annular volume:

$$V_{hdc} = \left(\frac{9.875^2 - 8.5^2}{1029.4}\right)(600) = (0.02454)(600) = 14.7 \text{ bbl}$$

Where: V_{hdc} = volume of drill collars in bbl

f) Total annular volume:

$$V_{at} = 1516.8 + 869.0 + 125.0 + 52.1 + 14.7 = 2577.6 \text{ bbl}$$

Where: V_{at} = total volume of annulus in bbl

g) Total volume of hole system:

$$V_s = (573.9 + 2577.6) = 3151.8 \text{ bbl}$$

Where: V_s = total volume of system in bbl

2.0.7 Strokes to Displace the Drill String, Annulus, and Total Circulation from the Rotary Table to the Flowline

$$C_s = \frac{V_s}{O_p} \tag{2.9}$$

Where: C_s = number of pump cycles or strokes for entire system
V_s = volume of system in bbl
O_p = pump output in bbl/stroke (stk)

Step 1: Calculate the strokes to pump down the drill string from rotary table to the bit:

$$C_{ds} = \left(\frac{573.9}{0.100}\right) = 5739 \text{ stk}$$

Where: C_{ds} = cycles or strokes for inside the drill string

Step 2: Calculate the strokes to pump up the annulus from the bit to the flow line:

a) Open hole/drill collar annulus:

$$C_{dca} = \left(\frac{14.7}{0.100}\right) = 147 \text{ stk}$$

Where: C_{dca} = cycles or strokes for open hole/drill collar annulus

b) Open hole/heavy weight drill pipe annulus:

$$C_{hwdpa} = \left(\frac{52.1}{0.100}\right) = 5210 \text{ stk}$$

Where: C_{hwdpa} = cycles or strokes for open hole/heavy weight drill pipe annulus

c) Open hole/drill pipe annulus:

$$C_{dpa} = \left(\frac{125.0}{0.100}\right) = 1250 \text{ stk}$$

Where: C_{dpa} = cycles or strokes for open hole/drill pipe annulus

d) Casing/drill pipe annulus:

$$C_{ca} = \left(\frac{869.0}{0.100}\right) = 8690 \text{ stk}$$

Where: C_{ca} = cycles or strokes for casing/drill pipe annulus

e) Riser/drill pipe annulus:

$$C_{ra} = \left(\frac{1516.8}{0.100}\right) = 15{,}168 \text{ stk}$$

Where: C_{ra} = cycles or strokes for riser/drill pipe annulus

f) Total strokes to circulate down the drill string and up the annulus:

$$C_t = (5739) + (147 + 5210 + 1250 + 8690 + 15168) = 36{,}204 \text{ stk}$$

g) Time to circulate the various sections:

$$T_t = \left(\frac{5739}{210}\right) + \left(\frac{30{,}365}{210}\right) = 172.4 \text{ min}$$

Where: T_t = total circulation time in minutes

NOTE: When the booster pump is on, the strokes for the riser/drill pipe annulus increase.

h) Riser/drill pipe annulus with the mud and booster pumps on:

$$C_{ra} = \left(\frac{1516.8}{0.100 + 0.051}\right) = 10{,}045 \text{ stk}$$

Where: C_{ra} = strokes for riser/drill pipe annulus

i) Time to circulate the various sections with the mud and booster pumps on:

$$T_t = \left(\frac{5739}{210}\right) + \left(\frac{147 + 5210 + 8690}{210}\right) + \left(\frac{15168}{210 + 180}\right) = 133.1 \text{ min}$$

2.1 Slug Calculations

2.1.1 Barrels of Slug Required for a Desired Length of Dry Pipe

Step 1: Calculate the hydrostatic pressure required to give desired mud drop inside the drill pipe:

$$S_{HP} = (W_m)(0.052)(L_{pd}) \tag{2.10}$$

Where: S_{HP} = slug hydrostatic pressure in psi
W_m = mud weight in lbm/gal
L_{pd} = length of dry pipe in ft

Step 2: Calculate the difference in pressure gradient between the slug weight and the mud weight:

$$S_{PG} = (S_w - W_m)(0.052) \tag{2.11}$$

Where: S_{PG} = slug pressure gradient in psi/ft
S_w = slug weight in lbm/gal
W_m = mud weight in use in lbm/gal

Step 3: Calculate the length of the slug in the drill pipe:

$$S_l = \left(\frac{S_{HP}}{S_{PG}}\right) \tag{2.12}$$

Where: S_l = slug length in ft

Step 4: Calculate the volume of the slug in bbl:

$$S_v = (S_l)(V_{cdp}) \tag{2.13}$$

Where: S_v = volume of slug in bbl
V_{cdp} = capacity of drill pipe in bbl/ft

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

Desired length of dry pipe (2 stands)	= 184 ft
Mud weight	= 12.2 lbm/gal
Slug weight	= 13.2 lbm/gal
Drill pipe capacity (6⅝ in.)	= 0.03457 bbl/ft

Step 1: Hydrostatic pressure required:

$$S_{HP} = (12.2)(0.052)(184) = 117 \text{ psi}$$

Step 2: Difference in pressure gradient:

$$S_{PG} = (13.2 - 12.2)(0.052) = 0.052 \text{ psi/ft}$$

Step 3: Length of slug in drill pipe:

$$S_l = \left(\frac{117}{0.052}\right) = 2250 \text{ ft}$$

Step 4: Volume of slug:

$$S_v = (2250)(0.03457) = 77.8 \approx 80.0 \text{ bbl}$$

2.1.2 Weight of Slug Required for a Desired Length of Dry Pipe with a Set Volume of Slug

Step 1: Calculate the length of the slug in the drill pipe in ft:

$$S_l = \left(\frac{S_v}{V_{cdp}}\right) \tag{2.14}$$

Where: S_l = slug length in ft

Step 2: Calculate the hydrostatic pressure required to give the desired drop of mud inside the drill pipe in psi (from equation (2.8)):

$$S_{HP} = (W_m)(0.052)(L_{pd})$$

Where: S_{HP} = slug hydrostatic pressure in psi
W_m = mud weight in lbm/gal
L_{pd} = length of dry pipe in ft

Step 3: Calculate the weight of the desired slug:

$$S_w = \left(\frac{\left(\frac{S_{HP}}{0.052} \right)}{S_l} \right) + W_m \tag{2.15}$$

Where: S_w = slug weight in lbm/gal

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

Desired length of dry pipe (2 stands)	= 184 ft
Mud weight	= 12.2 lbm/gal
Volume of slug	= 75 bbl
Drill pipe capacity (6⅝ in.)	= 0.03457 bbl/ft

Step 1: Length of slug in drill pipe:

$$S_l = \left(\frac{75}{0.03457} \right) = 2170 \text{ ft}$$

Step 2: Hydrostatic pressure required:

$$S_{HP} = (12.2)(0.052)(184) = 117 \text{ psi}$$

Step 3: Weight of slug:

$$S_w = \left(\frac{\left(\frac{117}{0.052} \right)}{2170} \right) + 12.2 = 13.3 \text{ lbm/gal}$$

2.1.3 Volume, Height, and Pressure Gained Because of Placement of Slug in Drill Pipe

Step 1: Calculate the volume gained in mud pits after slug is pumped, due to U-tubing:

$$S_{pit} = (S_l)(V_{cdp}) \tag{2.16}$$

Where: S_{pit} = volume increase in mud pit in bbls
V_{cdp} = capacity of drill pipe in bbl/ft

Step 2: Calculate the height of slug in the annulus in ft:

$$S_h = (V_{ac})(S_v) \tag{2.17}$$

Where: S_h = height of the slug in the annulus in ft
V_{ac} = volume of the open hole and drill pipe in ft/bbl

Step 3: Calculate the hydrostatic pressure gained in the annulus because of the slug in psi:

$$S_{HP} = (S_h)(S_w - W_m)(0.052) \tag{2.18}$$

Where: S_{HP} = increase in hydrostatic pressure in the annulus due to the slug in psi

Example: Calculate the increase in hydrostatic pressure gained with the following:

Feet of dry pipe (2 stands)	= 184 ft
Slug volume	= 75 bbl
Slug weight	= 13.2 lbm/gal
Mud weight	= 12.2 lbm/gal
Drill pipe capacity (6⅝ in.)	= 0.03457 bbl/ft
Annulus volume (9⅞ in. × 8½ in.)	= 40.74 ft/bbl
Annulus volume (9⅞ in. × 6⅝ in.)	= 19.20 ft/bbl

Step 1: Volume gained in mud pits after slug is pumped, due to U-tubing:

$$S_{pit} = (184)(0.03457) = 6.4 \text{ bbl}$$

Step 2: Calculate the height of slug in the annulus in ft:

Note that the slug volume will cover the drill collars and part of the drill pipe section.

$$S_h = \left[(19.2)\left(75 - \left(\frac{600}{40.74}\right)\right)\right] + (600) = 1757.2 \text{ ft}$$

Step 3: Calculate the hydrostatic pressure gained in the annulus because of the slug:

$$S_{HP} = (1757.2)(13.2 - 12.2)(0.052) = 91.4 \text{ psi}$$

2.1.4 English Units Calculation

Step 1: Volume gained pumping slug in bbl:

$$S_{vg} = \left((S_v)\left(\frac{S_w}{W_m}\right)\right) - (S_v) \tag{2.19}$$

Where: S_{vg} = volume gained due to pumping slug in bbl

Step 2: Calculate the length of dry pipe after pumping the slug in ft:

$$S_{ldp} = \left(\frac{S_{vg}}{V_{cdp}}\right) \tag{2.20}$$

Where: S_{ldp} = length of dry pipe after pumping the slug in ft

Example: Calculate the number of barrels of mud gained due to pumping the slug and calculate the feet of dry pipe:

Mud weight	= 12.6 lbm/gal
Slug weight	= 14.2 lbm/gal
Barrels of slug pumped	= 50 bbl
Drill pipe capacity (6⅝ in.)	= 0.03457 bbl/ft

Step 1: Volume gained due to pumping slug:

$$S_{vg} = \left((50)\left(\frac{14.2}{12.6}\right)\right) - (50) = 6.35 \text{ bbl}$$

Step 2: Calculate the number of feet of dry pipe after pumping the slug:

$$S_{ldp} = \left(\frac{6.35}{0.03457}\right) = 184 \text{ ft}$$

2.1.5 SI Calculation

Convert English units to SI units with:

Barrels (bbl) × 0.159 = cubic meters (m^3)

Mud weight (lbm/gal) × 120 = kilograms/cubic meter (kg/m^3)

2.2 Accumulator Capacity

2.2.1 Useable Volume per Bottle

NOTE: The following will be used as guidelines:

Volume per bottle	= 10 gal
Precharge 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:

$$(P_1)(V_1) = (P_2)(V_2) \tag{2.21}$$

Where: P = pressure in psi
V = volume in gal

2.2.2 Surface Application

Step 1: Calculate the hydraulic fluid necessary to increase pressure from the precharge to the minimum:

$$(1000)(10) = (1200)(V_2)$$

$$V_2 = \frac{(1000)(10)}{1200} = 8.33 \text{ gal}$$

The nitrogen has been compressed from 10.0 gallons to 8.33 gallons.

Next, calculate the volume of the hydraulic fluid in the bottle.

10.0 – 8.33 = 1.67 gal of hydraulic fluid per bottle.

NOTE: This is dead hydraulic fluid. The pressure must not drop below the minimum 1200 psi value.

Step 2: Calculate the amount of hydraulic fluid necessary to increase pressure from precharge to the maximum:

$$(1000)(10) = (3000)(V_2)$$

$$V_2 = \frac{(1000)(10)}{3000} = 3.33 \text{ gal}$$

The nitrogen has been compressed from 10 gallons to 3.33 gallons.

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

Step 3: Calculate the useable volume per bottle in gal:

$$V_u = (V_{tb} - V_d) \tag{2.22}$$

Where: V_u = useable volume per bottle in gal
V_{tb} = total hydraulic volume per bottle in gal
V_d = dead hydraulic volume per bottle in gal

$$V_u = (6.67 - 1.67) = 5.0 \text{ gal}$$

2.2.3 English Units

$$V_u = (V_b)\left(\left(\frac{P_p}{P_f}\right) - \left(\frac{P_p}{P_m}\right)\right) \tag{2.23}$$

Where: V_b = volume capacity of bottle in gal
P_p = precharge pressure in psi
P_f = minimum pressure after activation in psi
P_m = maximum system pressure in psi

Example: Calculate the amount of usable hydraulic fluid delivered from a 20-gal bottle:

Precharge pressure = 1000 psi (P_P)
Maximum system pressure = 3000 psi (P_m)
Final pressure = 1200 psi (P_f)

$$V_u = (20)\left(\left(\frac{1000}{1200}\right) - \left(\frac{1000}{3000}\right)\right) = 10 \text{ gal}$$

2.2.4 Deepwater Applications

In deepwater applications, the hydrostatic pressure exerted by the hydraulic fluid must be compensated for in the calculations due to the hydrostatic head of the seawater:

Example: Same guidelines as in surface applications:

Water depth	= 1500 ft
Hydrostatic pressure on the hydraulic fluid	= 889 psi or [(8.55)(0.052)(2000)]

Step 1: Adjust all hydraulic fluid pressures for the hydrostatic pressure of the seawater:

$P_p = (1000 + 889) = 1889$ psi
$P_m = (3000 + 889) = 3889$ psi
$P_f = (1200 + 889) = 2089$ psi

Step 2: Calculate the volume of hydraulic fluid necessary to increase the pressure from the precharge to the minimum:

$$(1889)(10) = (2089)(V_2)$$

$$V_2 = \frac{(1889)(10)}{(2089)} = 9.04 \text{ gal}$$

$$V_u = (10 - 9.04) = 0.96 \text{ gal}$$

NOTE: This is dead hydraulic fluid. The pressure must not drop below the minimum value of 2089 psi.

Step 3: Calculate the amount of hydraulic fluid necessary to increase the pressure from the precharge to the maximum:

$$(1889)(10) = (3889)(V_2)$$

$$V_2 = \frac{(1889)(10)}{(3889)} = 4.86 \text{ gal}$$

The nitrogen has been compressed from 10 gal to 4.86 gal.

$10 - 4.86 = 5.14$ gal of hydraulic fluid per bottle

Step 4: Calculate the useable hydraulic fluids per bottle:

$V_u = (4.86 - 0.96) = 3.9$ gal

2.2.5 Accumulator Precharge Pressure

The following is a method of calculating the average accumulator precharge pressure by operating the unit with the charge pumps switched off:

$$P_p = \left(\frac{V_r}{V_t}\right)\left(\frac{((P_e)(P_s))}{(P_s - P_f)}\right) \tag{2.24}$$

Where: P_p = precharge pressure in psi
V_r = volume of hydraulic fluid removed in gal
V_t = total accumulator volume in gal
P_f = final accumulator pressure in psi
P_s = starting accumulator pressure in psi

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

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

$$P_p = \left(\frac{20}{180}\right)\left(\frac{((2200)(3000))}{(3000 - 2200)}\right) = (0.1111)\left(\frac{(6{,}600{,}000)}{800}\right) = 917\,\text{psi}$$

2.3 Bulk Density of Cuttings (Using Mud Balance)

Procedure:

1. Cuttings must be washed free of mud. In an oil mud, the base oil can be used instead of water.
2. Set mud balance at 8.33 lbm/gal.
3. Fill the mud balance with the clean cuttings until a balance is obtained with the lid in place.

4. Remove lid, fill cup with fresh water (cuttings included), replace lid, and dry outside of mud balance.
5. Move counterweight to obtain new weight reading on the lbm/gal scale.

Step 1: The specific gravity of the cuttings is calculated as follows:

$$SG_c = \left(\frac{1}{2 - ((0.12)(W_r))}\right) \tag{2.25}$$

Where: SG_c = specific gravity (average bulk density) of cuttings in gm/cm^3
W_r = resulting weight with cuttings plus water in lbm/gal

Example: Calculate the average bulk density of cuttings with a final weight of 13.0 lbm/gal:

$$SG_c = \left(\frac{1}{2 - ((0.12)(13.0))}\right) = 2.27\ gm/cm^3$$

A graph may also be prepared to provide a quick direct reading of the average bulk density.

2.4 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.

2.4.1 Calculate the Length of BHA Necessary for a Desired Weight on the Bit

Step 1: Calculate the buoyancy factor:

$$BF = \left(\frac{W_s - W_m}{W_s}\right) \tag{2.26}$$

Where: BF $=$ buoyancy factor
W_s $=$ weight of steel in lbm/gal
W_m $=$ weight of mud or completion brine fluid (CBF) in lbm/gal

Step 2: Calculate the length of BHA necessary for a desired weight on the bit:

$$L_{BHA} = \left(\frac{(W_{bit})(f_{dc})}{(W_{dc})(BF)}\right) \tag{2.27}$$

Where: L_{BHA} $=$ length of BHA necessary for a desired WOB in ft
W_{bit} $=$ desired weight on bit (WOB) in lb
f_{dc} $=$ safety factor to place neutral point in drill collars
W_{dc} $=$ weight of drill collar in lb/ft

Example: Calculate the BHA length necessary for a desired WOB:

Desired WOB while drilling	= 50,000 lb
Safety factor	= 15%
Mud weight	= 12.0 lbm/gal
Drill collar weight (8 in. × 3 in.)	= 147 lb/ft
Weight of steel	= 65.5 lbm/gal

Step 1: Calculate the buoyancy factor:

$$BF = \left(\frac{65.5 - 12.0}{65.5}\right) = 0.8168$$

Step 2: Calculate the length of the BHA necessary for this weight on bit:

$$L_{BHA} = \left(\frac{(50{,}000)(1.15)}{(147)(0.8168)}\right) = 479 \text{ ft}$$

2.4.2 Calculate the 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.

Step 1: Calculate the buoyancy factor (from equation (2.26)):

$$BF = \left(\frac{W_s - W_m}{W_s}\right)$$

Step 2: Calculate the maximum length of drill pipe that can be run into the hole with a specific BHA assembly:

$$L_{max} = \left(\frac{\left(\left((TS)(1 - f_{dp})\right) - MOP - W_{BHA}\right)(BF)}{W_{dp}}\right) \qquad (2.28)$$

Where: L_{max} = maximum length of drill pipe that can be run into the hole with a specific BHA in feet
TS = tensile strength for new drill pipe in lb
f_{dp} = safety factor to correct new drill pipe to no. 2 pipe
MOP = margin of overpull in lb
W_{BHA} = weight of the BHA in lb
W_{dp} = weight of the drill pipe with tool joints in lb/ft

Step 3: Calculate the total depth that can be reached with a specific BHA in ft:

$$D_T = L_{max} + L_{BHA} \qquad (2.29)$$

Where: D_T = total depth that can be reached with a specific BHA in ft
L_{BHA} = length of BHA to be run in ft

Example: Drill pipe (6⅝ in.) = 25.20 lb/ft (S-135)
Tensile strength = 881,040 lb
BHA weight in air = 50,000 lb
BHA length = 500 ft
Desired overpull = 100,000 lb
Mud weight = 13.5 lbm/gal
Safety factor = 10%

Step 1: Buoyancy factor:

$$BF = \left(\frac{65.5 - 13.5}{65.5}\right) = 0.7939$$

Step 2: Calculate the maximum length of drill pipe that can be run into the hole in ft:

$$L_{max} = \left(\frac{(((881{,}040)(1-0.10)) - 100{,}000 - 50{,}000)(0.7939)}{25.20}\right)$$
$$= 25{,}513 \text{ ft}$$

Step 3: Calculate the total depth that can be reached with this BHA and this drill pipe in ft:

$$D_T = 25{,}513 + 500 = 26{,}013 \text{ ft}$$

2.5 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

2.5.1 Round Trip Ton-Miles (RT_{TM})

$$RT_{TM} = \frac{\left((W_{bdp})(D)(L_{ps} + D)\right) + ((2D)((2W_{tb}) + W_{bdc}))}{(5280)(2000)} \tag{2.30}$$

Where: RT_{TM} = round trip in ton-miles
W_{bdp} = buoyed weight of drill pipe in lb/ft
D = depth of hole in ft
L_{ps} = length of one stand of drill pipe (average) in ft
W_{tb} = weight of traveling block or top drive assembly in lb
W_{bdc} = buoyed weight of drill collars in mud minus the buoyed weight of the same length of drill pipe in lb
2000 = number of pounds in one short ton
5280 = number of ft in one mile

Example: Calculate the round trip ton-miles with the following data:

Mud weight	= 12.6 lbm/gal
Measured depth	= 15,000 ft
Drill pipe weight (6⅝ in.)	= 25.20 lb/ft (S-135)
Drill collar weight	= 147 lb/ft
Drill collar length	= 500 ft
Traveling block assembly	= 100,000 lb
Average length of one stand	= 92 ft (treble)

Step 1: Calculate the buoyancy factor (from equation (2.26)):

$$BF = \left(\frac{65.5 - 12.6}{65.5}\right) = 0.8076$$

Step 2: Calculate the buoyed weight of the drill pipe in mud in lb/ft:

$$W_{dp} = (25.2)(0.8076) = 20.59\ \text{lb/ft}$$

Step 3: Calculate the buoyed weight of the drill collars in the mud minus the buoyed weight of the same length of drill pipe in lb:

$$W_{dc} = ((500)(147)(0.8076)) - ((500)(25.2)(0.8076)) = 49{,}183\ \text{lb}$$

Step 4: Calculate the round trip ton-miles:

$$RT_{TM} = \frac{((20.59)(15{,}000)(92 + 15{,}000)) + ((30{,}000)(200{,}000 + 49{,}183))}{(5280)(2000)}$$
$$= 1149.3\ \text{ton-miles}$$

2.5.2 Drilling or "Connection" Ton-Miles

The ton-miles calculation used for the drilling operation is expressed in terms of the work performed making round trips. These are the actual ton-miles of work required to drill down the length of a joint of drill pipe ($\approx$30 ft), plus picking up, connecting, and starting to drill with the next joint.

To determine connection or drilling ton-miles, multiply 3 times the difference between the ton-miles for the current round trip minus the ton-miles for the previous round trip:

$$TM_D = 3(TM_2 - TM_1) \tag{2.31}$$

Where: TM_D = drilling or "connection" ton-miles
TM_2 = ton-miles for one round trip—depth where drilling stopped before coming out of the hole
TM_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

$$TM_D = 3(1175.2 - 1149.3) = 77.7 \text{ ton-miles}$$

2.5.3 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:

$$TM_C = 3(TM_4 - TM_3) \tag{2.32}$$

Where: TM_C = ton-miles while coring
TM_4 = ton-miles for one round trip—depth where coring stopped before coming out of the hole
TM_3 = ton-miles for one round trip—depth where coring started

2.5.4 Ton-Miles Setting Casing

The calculation of the ton-miles for setting casing is determined just like the one for drill pipe, but with the buoyed weight of the casing being used. The result is multiplied by one-half because setting casing is a one-way (½ round trip) operation. Ton-miles for setting casing can be determined from the following formula:

$$TM_{CSG} = \frac{0.5\left((W_{csgb})(D)(L_{csg} + D)\right) + ((D)(W_b))}{(5280)(2000)} \tag{2.33}$$

Where: TM_{CSG} = ton-miles setting casing
W_{csgb} = buoyed weight of casing, lb/ft
L_{css} = length of one joint of casing, ft
W_b = weight of traveling block assembly, lb

2.5.5 Ton-Miles While Making Short Trips

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

$$TM_{ST} = 3(TM_6 - TM_5) \tag{2.34}$$

Where: TM_{ST} = 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 at the end of the short trip

2.5.6 Cutoff Practices for Rotary Drilling Line

Refer to Section 6 in API RP 9B for recommended cutoff lengths for drill line based on ton-mile calculations.

Table 2-1
Ton-Mile Goal per Foot of Rope*

Drum Diameter	Rope Diameter 1 in.	1⅛ in.	1¼ in.	1⅜ in.	1½ in.	1⅝ in.	1¾ in.	2 in.
18 in.	6.0	9.0						
19 in.	6.0	9.0						
20 in.	7.0	9.0						
21 in	7.0	10.0						
22 in.	7.0	10.0						
23 in.	8.0	10.0	13.0					
24 in.	8.0	10.0	13.0	17.0				
25 in.	8.0	10.0	14.0	17.0				
26 in.	9.0	11.0	14.0	17.0				
27 in.	9.0	12.0	15.0	18.0				
28 in.		12.0	15.0	18.0				
29 in.		12.0	15.0	18.0				
30 in.		13.0	16.0	19.0	20.0			
31 in.			16.0	19.0	21.0			
32 in.			17.0	20.0	22.0			
33 in.			17.0	20.0	23.0			
34 in.			18.0	21.0	24.0			
35 in.				21.0	25.0			
36 in.				22.0	25.0	28	30	
42 in.								32
48 in.								
60 in.								

*Premium ropes such as plastic impregnated can provide additional service.

2.5.7 Calculate the Length of Drill Line Cutoff

$$DL_{CO} = \left(\frac{RT_{TM}}{CO_G}\right)$$

Where: DL_{CO} = Drill line cutoff in ft
CO_G = Cutoff goal from Table 2-1

Using the ton-miles calculated in **Step 4** of **Section 2.5.1**, calculate the amount of drill line to be cut.

Data: Drum circumference 42 inches
Drill line diameter 2 inches
Ton-miles calculated 1149.3

$$DL_{CO} = \left(\frac{1149.3}{32}\right) = 35.9 \text{ ft}$$

2.6 Cementing Calculations

2.6.1 Cement Additive Calculations

Step 1: Calculate the weight of additive per sack of cement in lb:

$$W_{ca} = (V_{a\%})(94.0) \tag{2.35}$$

Where: W_{ca} = weight of cement additive in lb
$V_{a\%}$ = volume percent of additive for cement mixture
94.0 = pounds of cement in one sack (sk)

Step 2: Total water requirement for each sack of cement in gal/sk:

$$V_{cwt} = V_{cw} + V_{aw} \tag{2.36}$$

Where: V_{cwt} = total volume of water required for each sack of cement in gal/sk
V_{cw} = volume of water required for cement portion in gal/sk (ref: Table 2-2)
V_{aw} = volume of water required for additive portion in gal/sk (ref: Table 2-2)

Step 3: Calculate the volume of the cement slurry in gal/sk:

$$V_{cs} = \left(\frac{94.0}{(SG_{cmt})(8.33)}\right) + \left(\frac{W_{ca}}{(SG_a)(8.33)}\right) + V_{cwt} \tag{2.37}$$

Where: V_{cs} = volume of cement slurry in gal/sk
SG_{cmt} = specific gravity of dry cement
SG_a = specific gravity of dry additive
8.33 = density of fresh water in lbm/gal

Step 4: Calculate the yield of the cement slurry in ft^3/sk:

$$Y_{cs} = \left(\frac{V_s}{7.48}\right) \tag{2.38}$$

Where: Y_{cs} = yield of cement slurry mixture in ft^3/sk
7.48 = volume of fresh water in gal/ft^3

Step 5: Calculate the cement slurry density in lbm/gal:

$$W_{cs} = \left(\frac{94.0 + W_{ca} + (8.33(V_{cwt}))}{V_s}\right) \tag{2.39}$$

Where: W_{cs} = weight of cement slurry in lbm/gal

Example: Using a Class A cement plus 4% bentonite with normal mixing water, calculate the following:

1. Amount of bentonite to add in lb/sk
2. Total water volume required for the slurry in gal/sk
3. Slurry yield in ft^3/sk
4. Slurry weight in lbm/gal

Step 1: Calculate the weight of the bentonite additive:

$$W_{ca} = (0.04)(94.0) = 3.76\ \text{lb/sk}$$

Step 2: Calculate the total water requirement per sack of cement used:

$$V_{cwt} = 5.2 + 2.6 = 7.8\ \text{gal/sk}$$

Step 3: Calculate the total volume of the cement slurry:

$$V_{cs} = \left(\frac{94.0}{(3.14)(8.33)}\right) + \left(\frac{3.76}{(2.65)(8.33)}\right) + 7.8 = 11.56\ \text{gal/sk}$$

Step 4: Calculate the yield of the cement slurry:

$$Y_{cs} = \left(\frac{11.56}{7.48}\right) = 1.55\ \text{ft}^3/\text{sx}$$

Step 5: Calculate the cement slurry density:

$$W_{cs} = \left(\frac{94.0 + 3.76 + (8.33(7.8))}{11.56}\right) = 14.08\ \text{lb/gal}$$

2.6.2 Water Requirements

Step 1: Calculate the weight of cement additive materials in lb/sk:

$$W_{cam} = 94.0 + (8.33(V_{cwt})) + (94.0(V_{\%})) \tag{2.40}$$

Where: W_{cam} = weight of cement additive materials in lb/sk

Step 2: Calculate the water requirement for the slurry using material balance equation:

$$(D_1)(V_1) = (D_2)(V_2) \tag{2.41}$$

Where: D_1 = density of item 1 in consistent units
V_1 = volume of item 1 in consistent units
D_2 = density of item 2 in consistent units
V_2 = volume of item 2 in consistent units

Example: Using a Class H cement plus 6% bentonite to be mixed at 14.0 lb/gal, calculate the following:

1. Bentonite requirement in lb/sk
2. Water requirement in gal/sk
3. Slurry yield in ft^3/sk
4. Check the slurry weight in lbm/gal

Step 1: Calculate the weight of cement additive materials:

$$W_{cam} = 94.0 + (8.33(x)) + (94.0(0.06)) = 99.64 + (8.33x)\text{lb/sk}$$

Step 2: Calculate the volume of cement slurry:

$$V_{cs} = \left(\frac{94.0}{(3.14)(8.33)}\right) + \left(\frac{5.64}{(2.65)(8{,}33)}\right) + x = 3.86 + x\ \text{gal/sk}$$

Step 3: Calculate the water requirement using the material balance equation:

$$
\begin{aligned}
(99.64 + 8.33x) &= (3.86 + x)\,(14.0)\\
(99.64 + 8.33x) &= (54.04 + 14.0x)\\
(99.64 - 54.04) &= (14.0x - 8.33x)\\
(45.6) &= (5.67x)\\
\frac{45.6}{5.67} &= x\\
8.04 &= x \approx 8.0\,\text{gal/sk water requirement per sack of cement}
\end{aligned}
$$

Step 4: Calculate the yield of the cement slurry:

$$Y_{cs} = \left(\frac{3.6 + 0.26 + 8.0}{7.48}\right) = 1.59\ \text{ft}^3/\text{sk}$$

Step 5: Recheck the cement slurry density:

$$W_{cs} = \left(\frac{94.0 + 5.64 + (8.33(8.0))}{11.86}\right) = 14.0\ \text{lb/gal}$$

2.6.3 Field Cement Additive Calculations

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

Cement program:	cement	= 240 sk
	slurry density	= 13.8 lbm/gal
	mixing water	= 8.6 gal/sk
	bentonite to be *prehydrated*	= 1.5%

Step 1: Calculate the volume of mixing water required in gal:

$$V_{cwt} = (240)(8.6) = 2064\ \text{gal}$$

Step 2: Calculate the total weight of mixing water in lb:

$$W_{mw} = (2064)(8.33) = 17{,}193\ \text{lb}$$

Where: W_{mw} = total weight of mixing water in lb

Step 3: Calculate the amount of bentonite required in lb:

$W_{ben} = (17{,}193)(0.015) = 258$ lb

Where: W_{ben} = weight of bentonite required in lb

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

Cement program:	cement	= 240 sk
	Halad (fluid loss)	= 0.50%
	CFR-2 (dispersant)	= 0.40%

Step 1: Calculate the weight of the cement:

$W_{cmt} = (240)(94) = 22{,}560$ lb

Step 2: Calculate the weight of the fluid loss additive:

Halad = (22,560)(0.005) = 112.8 lb

Step 3: Calculate the weight of the dispersant:

$CFR - 2 = (22{,}560)(0.004) = 90.24$ lb

Table 2-2
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 2-2 (continued)

Material	Water Requirement gal/94 lb/sk	Specific Gravity
Common Cement Additives		
Attapulgite	1.3 for 2% gel 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 for 2% gel 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 for 10% in cement	2.10
Diacel LWL	0 (up to 0.7%) 0.8 : 1/1% in cement	1.36
Gilsonite	2 for 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 1b/ft^3	2.20
Perlite 6	6/38 1b/ft^3	-
Pozmix® A	4.6–5.0	2.46
Salt (NaCl)	0	2.17
Sand Ottawa	0	2.63
Silica flour	1.6 for 35% flour 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

2.6.4 Weighted Cement Calculations

Step 1: Calculate the amount of high density additive required per sack of cement to achieve a required cement slurry density in lb:

$$W_{ca} = \frac{\left(\frac{(W_{cs})(11.207983)}{SG_{cmt}}\right) + ((W_{cs})(V_{cwt})) - 94.0 - ((8.33)(W_{cs}))}{\left(1 + \left(\frac{V_{wa}}{100}\right)\right) - \left(\frac{W_{cs}}{(SG_a)(8.33)}\right) - \left((W_{cs})\left(\frac{V_{wa}}{100}\right)\right)} \tag{2.42}$$

Where: W_{ca} = additive required per sack of cement in lb
W_{cs} = required cement slurry density in lbm/gal
SG_{cmt} = specific gravity of cement
V_{cwt} = water requirement of cement in gal/sk
V_{wa} = water requirement of additive in gal/sk
SG_a = specific gravity of additive

Table 2-3
Weighting Agents for Cement

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

Example: Calculate how much hematite (in lb/sk) is required to increase the density of Class H cement to 17.5 lbm/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

$$W_a = \frac{\left(\frac{(17.5)\,(11.207983)}{3.14}\right) + ((17.5)\,(4.3)) - 94.0 - ((8.33)\,(4.3))}{\left(1 + \left(\frac{0.34}{100}\right)\right) - \left(\frac{17.5}{(5.02)\,(8.33)}\right) - \left((17.5)\left(\frac{0.34}{100}\right)\right)}$$

$$W_a = \frac{(62.4649) + (75.25) - 94.0 - (35.819)}{(1.0034) - (0.418494) - (0.0595)} = \frac{(7.8959)}{(0.525406)}$$

$$= 15.1 \text{ lb per sack of cement}$$

2.6.5 Calculations for the Number of Sacks of Cement Required

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

Step 1: Calculate the following capacities:

a) Annular capacity in ft^3/ft:

$$V_{acf} = \left(\frac{D_h{}^2 - D_p{}^2}{183.35}\right) \tag{2.43}$$

Where: V_{acf} = annular capacity in ft^3/ft

b) Casing capacity in ft^3/ft:

$$V_{cc} = \left(\frac{D_i{}^2}{183.35}\right) \tag{2.44}$$

Where: V_{cc} = casing capacity in ft^3/ft

c) Casing capacity in bbl/ft (from equation (2.1)):

$$V_{pc} = \left(\frac{D_i{}^2}{1029.4}\right)$$

Step 2: Calculate the number of sacks of LEAD or FILLER cement required:

$$SR_L = \frac{(L_{cmt})(V_{ac})\left(1 + \left(\frac{V_{\%e}}{100}\right)\right)}{Y_L} \tag{2.45}$$

Where: SR_L = cement required for LEAD job in sk
L_{cmt} = length of section to be cemented in ft
$V_{\%e}$ = excess volume for job in %
Y_L = yield of LEAD cement in ft^3/sk

Step 3: Calculate the number of sacks of TAIL or NEAT cement required:

$$SR_{Ta} = \frac{(L_{cmt})(V_{ac})\left(1 + \left(\frac{V_{\%e}}{100}\right)\right)}{Y_T} \tag{2.46}$$

Where: SR_{Ta} = cement required in annulus for the TAIL job in sk
Y_T = yield of TAIL cement in ft^3/sk

$$SR_{Tc} = \frac{(L_{cmt})(V_{cc})}{Y_T} \tag{2.47}$$

Where: SR_{Tc} = cement required inside the casing for the TAIL job in sk

Step 4: Calculate the total sacks of TAIL cement required:

$$SR_{Tt} = SR_{Ta} + SR_{Tc} \tag{2.48}$$

Step 5: Calculate the casing capacity down to the float collar:

$$V_{fc} = (V_{pc})(L_{fc}) \tag{2.49}$$

Where: V_{fc} = casing capacity down to the float collar in bbl
L_{fc} = length of casing from the surface to the float collar in ft

Step 6: Calculate the number of strokes required to bump the plug:

$$C_{bp} = \left(\frac{V_{pc}}{O_p}\right) \tag{2.50}$$

Where: C_{bp} = strokes to bump the plug

Example: Calculate the following based on the data listed below:

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	= 17½ in.
	Casing—54.5 lb/ft	= 13⅜ in.
	Casing ID	= 12.615 in.
	Float collar (number of feet above shoe)	= 44 ft
	Pump (5½ 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: Calculate the following capacities:

a) Annular capacity in ft^3/ft:

$$V_{ac} = \left(\frac{17.5^2 - 13.375^2}{183.35}\right) = 0.6946\ ft^3/ft$$

b) Casing capacity in ft^3/ft:

$$V_{cc} = \left(\frac{12.615^2}{183.35}\right) = 0.8679\ ft^3/ft$$

c) Casing capacity in bbl/ft:

$$V_{pc} = \left(\frac{12.615^2}{1029.4}\right) = 0.1545\ bbl/ft$$

Step 2: Calculate the number of sacks of LEAD or FILLER cement required:

$$SR_L = \frac{(2000)(0.6946)\left(1 + \left(\frac{50}{100}\right)\right)}{1.59} = 1311\,\text{sk}$$

Step 3: Calculate the number of sacks of TAIL or NEAT cement required:

$$SR_{Ta} = \frac{(1000)(0.6946)\left(1 + \left(\frac{50}{100}\right)\right)}{1.15} = 906\ \text{sk}$$

$$SR_{Tc} = \frac{(44)(0.8679)}{1.15} = 33\ \text{sk}$$

$$SR_{Tt} = 906 + 33 = 939\ \text{sk}$$

Step 4: Calculate the barrels of mud required to bump the top plug:

$$V_{fc} = (0.1545)(3000 - 44) = 456.7\ \text{bbl}$$

Step 5: Calculate the number of strokes required to bump the top plug:

$$C_{bp} = \left(\frac{456.7}{0.112}\right) = 4078\ \text{stk}$$

2.6.6 Calculations for the Number of Feet to Be Cemented

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

Step 1: Calculate the following capacities:

a) Annular capacity in ft^3/ft (from equation (2.43)):

$$V_{ac} = \left(\frac{{D_h}^2 - {D_p}^2}{183.35}\right)$$

b) Casing capacity in ft^3/ft (from equation (2.44)):

$$V_{cc} = \left(\frac{D_i^2}{183.35}\right)$$

Step 2: Calculate the slurry volume in ft^3:

$$V_{cs} = (ST_t)(Y_s) \tag{2.51}$$

Where: V_{cs} = volume of cement slurry in ft^3

Step 3: Calculate the amount of cement to be left in casing in ft^3:

$$V_{cc} = (L_{csg} - D_{st})(V_{cc}) \tag{2.52}$$

Where: V_{cc} = volume of cement left in casing in ft^3

Step 4: Calculate the height of cement in the annulus in ft:

$$H_{cmt} = \frac{\left(\frac{V_s - V_{cc}}{V_{ac}}\right)}{\left(1 + \left(\frac{V_{\%e}}{100}\right)\right)} \tag{2.53}$$

Where: H_{cmt} = height of cement slurry in the annulus in ft

Step 5: Calculate the depth of the top of the cement slurry in the annulus in ft:

$$D_{tcmt} = (L_c - L_{cmt}) \tag{2.54}$$

Where: D_{tcmt} = depth of the top of the cement slurry in the annulus in ft

Step 6: Calculate the volume of mud required to displace the cement in bbl:

$$V_{dcmt} = (L_p - L_{as})(V_p) \tag{2.55}$$

Where: V_{dcmt} = volume of mud required to displace cement slurry in bbl
L_{as} = length of distance between cementing tool and casing shoe in ft

Step 7: Calculate the number of strokes required to displace the cement slurry:

$$C_{dcmt} = \left(\frac{V_{dcmt}}{O_p}\right) \tag{2.56}$$

Where: C_{dcmt} = the number of strokes required to displace the cement

Example: Calculate the following from the data listed below:

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

Data: Casing setting depth = 3000 ft
Hole size = 17½ in.
Casing—54.5 lb/ft = 13⅜ 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: Calculate the following capacities:

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

$$V_{ac} = \left(\frac{17.5^2 - 13.375^2}{183.35}\right) = 0.6946\ \text{ft}^3/\text{ft}$$

b) Casing capacity in ft³/ft:

$$V_{cc} = \left(\frac{12.615^2}{183.35}\right) = 0.8679\ \text{ft}^3/\text{ft}$$

Step 2: Calculate the cement slurry volume in ft³:

$$V_{cs} = (500)(1.15) = 575\ \text{ft}^3$$

Step 3: Calculate the amount of cement, ft³, to be left in the casing:

$$V_{cc} = (3000 - 2900)(0.8679) = 86.79\ \text{ft}^3$$

Step 4: Calculate the height of the cement in the annulus in ft:

$$H_{cmt} = \frac{\left(\dfrac{575 - 86.79}{0.6946}\right)}{\left(1 + \left(\dfrac{50}{100}\right)\right)} = 468.58\ \text{ft}$$

Step 5: Calculate the depth of the top of the cement in the annulus:

$$D_{tcmt} = (3000 - 468.58) = 2531.42\ \text{ft}$$

Step 6: Calculate the number of barrels of mud required to displace the cement:

$$V_{dcmt} = (3000 - 100)(0.01766) = 51.5\ \text{bbl}$$

Step 7: Calculate the number of strokes required to displace the cement:

$$C_{dcmt} = \left(\frac{51.5}{0.136}\right) = 379\ \text{stk}$$

2.6.7 Setting a Balanced Cement Plug

Step 1: Calculate the following capacities:

a) Calculate the annular capacity between pipe or tubing and hole or casing in ft³/ft (from equation (2.43)):

$$V_{ac} = \left(\frac{{D_h}^2 - {D_p}^2}{183.35}\right)$$

b) Calculate the annular capacity between pipe or tubing and hole or casing in ft/bbl (from equation (2.4)):

$$V_{acf} = \left(\frac{1029.4}{D_h{}^2 - D_p{}^2}\right)$$

c) Hole or casing capacity in ft^3/ft (from equation (2.44)):

$$V_{cc} = \left(\frac{D_i{}^2}{183.35}\right)$$

d) Drill pipe or tubing capacity in ft^3/ft (from equation (2.44)):

$$V_{dpc} = \left(\frac{D_i{}^2}{183.35}\right)$$

e) Drill pipe or tubing capacity in bbl/ft (from equation (2.1)):

$$V_{pcb} = \left(\frac{D_i{}^2}{1029.4}\right)$$

Step 2: Calculate 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:

$$SR_{plug} = \frac{(L_{plug})(V_{acf})\left(1 + \left(\frac{V_{\%e}}{100}\right)\right)}{Y_{cs}} \tag{2.57}$$

Where: SR_{plug} = cement required for a given length of plug in sk
L_{plug} = length of plug in ft
V_{acf} = hole or casing capacity in ft^3/ft
$V_{\%e}$ = excess volume for job in %
Y_{cs} = yield of cement slurry in ft^3/sk

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:

$$L_{plug} = \left(\frac{\left(\frac{(SR_{plug})(Y_{cs})}{V_{ac}} \right)}{\left(1 + \left(\frac{V_{\%e}}{100} \right) \right)} \right) \tag{2.58}$$

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

Step 3: Calculate the spacer volume (usually water) to be pumped behind the cement slurry to balance the plug in bbl:

$$V_{spacer\ behind} = \left(\frac{V_{ac}}{\left(1 + \left(\frac{V_{\%e}}{100} \right) \right)} \right) (V_{spacer\ ahead})(V_{pc}) \tag{2.59}$$

Where: $V_{spacer\ behind}$ = volume of spacer pumped behind cement plug in bbl
$V_{spacer\ ahead}$ = volume of spacer pumped ahead of cement plug in bbl

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

Step 4: Calculate the plug length before the pipe is withdrawn in ft:

$$L_{plug} = \left[\left(\frac{(SR_{cmt})(Y_{cs})}{V_{ac}} \right) \left(1 + \left(\frac{V_{\%e}}{100} \right) \right) \right] + V_{pc} \tag{2.60}$$

Where: SR_{cmt} = cement required for plug in sk

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

Step 5: Calculate the fluid volume required to spot the plug in bbl:

$$V_{displace} = (L_p - L_{plug})(V_{pc}) - V_{spacer\ behind} \tag{2.61}$$

Where: $V_{displace}$ = volume of fluid required to spot the plug in bbl
L_p = length of pipe or tubing in ft

Example 1: A 300-ft plug is to be placed at a depth of 5000 ft. The open hole size is 8½ in. and the drill pipe is 3½ in.—13.3 lb/ft; ID—2.764 in. Ten barrels of water are to be pumped ahead of the slurry. Use a cement slurry yield of 1.15 ft^3/sk. Use an excess of 25% for the volume of the open hole or casing:

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: Calculate the following capacities:

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

$$V_{ac} = \left(\frac{8.5^2 - 3.5^2}{183.35}\right) = 0.3272\ ft^3/ft$$

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

$$V_{ac} = \left(\frac{1029.4}{8.5^2 - 3.5^2}\right) = 17.1569\ ft/bbl$$

c) Hole capacity in ft^3/ft:

$$V_{cc} = \left(\frac{8.5^2}{183.35}\right) = 0.3941\ ft^3/ft$$

d) Drill pipe capacity in bbl/ft:

$$V_{pc} = \left(\frac{2.764^2}{1029.4}\right) = 0.00742\ bbl/ft$$

Example 1: A 300-ft plug is to be placed at a depth of 5000 ft. The open hole size is 8½ in. and the drill pipe is 3½ in.—13.3 lb/ft; ID—2.764 in. Ten barrels of water will be pumped ahead of the slurry. Use a slurry yield of 1.15 ft^3/sk. Use 25% as the excess for the 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: Calculate the following capacities:

a) Annular capacity between drill pipe and hole in ft³/ft:

$$V_{ac} = \left(\frac{8.5^2 - 3.5^2}{183.35}\right) = 0.3272\ \text{ft}^3/\text{ft}$$

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

$$V_{acf} = \left(\frac{1029.4}{8.5^2 - 3.5^2}\right) = 17.1569\ \text{ft/bbl}$$

c) Hole capacity in ft³/ft:

$$V_{cc} = \left(\frac{8.5^2}{183.35}\right) = 0.3941\ \text{ft}^3/\text{ft}$$

d) Drill pipe capacity in bbl/ft:

$$V_{pb} = \left(\frac{2.764^2}{1029.4}\right) = 0.00742\ \text{bbl/ft}$$

e) Drill pipe capacity in ft³/ft:

$$V_{pf} = \left(\frac{2.764^2}{183.35}\right) = 0.0417\ \text{ft}^3/\text{ft}$$

Step 2: Calculate the number of sacks of dry cement required:

$$SR_L = \frac{(300)(0.3941)\left(1 + \left(\frac{25}{100}\right)\right)}{1.15} = 129\,\text{sk}$$

Step 3: Calculate the spacer volume (water) to be pumped behind the cement slurry to balance the plug in bbl:

$$V_{\text{spacer behind}} = \left(\frac{17.1569}{\left(1+\left(\frac{25}{100}\right)\right)}\right)(10)(0.00742) = 1.018 \text{ bbl}$$

Step 4: Calculate the plug length before the pipe is withdrawn in ft:

$$L_{\text{plug}} = \left[\left(\frac{(129)(1.15)}{0.3272}\right)\left(1+\left(\frac{25}{100}\right)\right)\right] + 0.0417 = 329 \text{ ft}$$

Step 5: Calculate the volume of the displacing fluid required to spot the plug in bbl:

$$V_{\text{displace}} = [(5000 - 329)(0.00742)] - 1.0 = 33.6 \text{ bbl}$$

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 8½ in. hole. Use 1.15 ft^3/sk for the cement slurry yield. The capacity of the 8½ in. hole = 0.3941 ft^3/ft. Use 50% as excess slurry volume:

$$L_{\text{plug}} = \left(\frac{\left(\frac{(100)(1.15)}{0.3941}\right)}{\left(1+\left(\frac{50}{100}\right)\right)}\right) = 194.5 \text{ ft}$$

2.6.8 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: 9⅝ in. casing—43.5 lb/ft in 12¼ 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 lbm/gal
Float collar (No. of feet above shoe)		= 44 ft

Step 1: Calculate the total hydrostatic pressure of cement and mud in the annulus:

a) Hydrostatic pressure of mud in annulus in psi:

$$HP_{ma} = (10.0)(0.052)(5000) = 2600 \text{ psi}$$

b) Hydrostatic pressure of LEAD cement in psi:

$$HP_{L} = (13.8)(0.052)(2000) = 1435 \text{ psi}$$

c) Hydrostatic pressure of TAIL cement in psi:

$$HP_{T} = (15.8)(0.052)(1000) = 822 \text{ psi}$$

d) Total hydrostatic pressure in annulus in psi:

$$HP_{ta} = (2600 + 1435 + 822) = 4857 \text{ psi}$$

Step 2: Calculate the total pressure inside the casing in psi:

a) Pressure exerted by the mud in psi:

$$HP_{m} = (10.0)(0.052)(8000 - 44) = 4137 \text{ psi}$$

b) Pressure exerted by the cement in psi:

$$HP_{cmt} = (15.8)(0.052)(44) = 36 \text{ psi}$$

c) Total pressure inside the casing in psi:

$$HP_{csg} = (4137 + 36) = 4173 \text{ psi}$$

Step 3: Calculate the differential pressure in psi:

$$P_d = (4857 - 4173) = 684 \text{ psi}$$

2.6.9 Hydraulicing Casing

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

Step 1: Calculate the difference in the pressure gradient between the cement and the mud in psi/ft:

$$PG_d = (W_{cmt} - W_m)(0.052) \tag{2.62}$$

Where: PG_d = difference in the pressure gradient between the cement and the mud in psi/ft

Step 2: Calculate the differential pressure (DP) between the cement and the mud in psi:

$$DP = (PG)(L_{csg}) \tag{2.63}$$

Where: DP = differential pressure between the cement and the mud in psi
L_{csg} = length of the casing in ft

Step 3: Calculate the area of the casing below the shoe in sq. in.:

$$A_{bcs} = (D_c)(0.7854) \tag{2.64}$$

Where: A_{bcs} = area below the casing shoe in sq. in.

Step 4: Calculate the upward force (F) in lb. This is the weight or total force acting at the bottom of the shoe:

$$F_{up} = (A_{bcs})(DP) \tag{2.65}$$

Where: F_{up} = upward force on casing in lb

Step 5: Calculate the downward force (W) in lb. This is the weight of the casing:

$$F_{down} = (W_{csg})(L_{csg})(BF) \quad (2.66)$$

Where: F_{down} = downward force or weight of the casing in lb
W_{csg} = weight of the casing in lb/ft

Step 6: Calculate the difference in these forces in lb:

$$F_d = (F_{down} - F_{up}) \quad (2.67)$$

Where: F_d = differential force in lb

Step 7: Calculate the pressure required to balance these forces so that the casing will not hydraulic out of the hole (move upward) in psi:

$$P_b = \left(\frac{F_d}{A_{bcs}}\right) \quad (2.68)$$

Where: P_b = pressure to balance forces in psi

Step 8: Calculate the mud weight increase required to balance the pressure in lbm/gal:

$$W_{mb} = \left(\frac{\left(\frac{P_b}{0.052}\right)}{L_{csg}}\right) \quad (2.69)$$

Where: W_{mb} = mud weight increase required to balance pressure in lbm/gal
L_{csg} = length of casing in ft

Step 9: Calculate the new mud weight in lbm/gal:

$$W_{mn} = (W_m + W_{mb}) \quad (2.70)$$

Where: W_{mn} = new mud weight to balance pressure in lbm/gal

Check the forces with the new mud weight with the following equations:

a) $PG = (W_{cmt} - W_m)(0.052)$

b) $DP = (PG)(L_{csg})$

c) $F_{up} = (A_{bcs})(DP)$

d) $F_d = (F_{down} - F_{up})$

Example: Calculate the forces and new mud weight with the following data:

Casing size	= 13⅜ in.—54 lb/ft
Cement weight	= 15.8 lbm/gal
Mud weight	= 8.8 lbm/gal
Buoyancy factor	= 0.8656
Well depth	= 164 ft

Step 1: Calculate the difference in pressure gradient between the cement and the mud in psi/ft:

$PG = (15.8 - 8.8)(0.052) = 0.364 \text{ psi/ft}$

Step 2: Calculate the differential pressure between the cement and the mud in psi:

$DP = (0.364)(164) = 60 \text{ psi}$

Step 3: Calculate the area of the casing below the shoe in sq. in.:

$A_{bcs} = (13.375^2)(0.7854) = 140.5 \text{ in.}^2$

Step 4: Calculate the upward force (F) in lb. This is the weight or total force acting at the bottom of the shoe:

$F_{up} = (140.5)(60) = 8430 \text{ lb}$

Step 5: Calculate the downward force (W) in lb. This is the weight of the casing:

$F_{down} = (54.5)(164)(0.8656) = 7737 \text{ lb}$

Step 6: Calculate the difference in these forces in lb:

$$F_d = (7737 - 8430) = -693 \text{ lb}$$

The resultant force is NEGATIVE! *Therefore:* Unless the casing is tied down or stuck, it will "hydraulic" out of the hole (move upward).

Step 7: Calculate the pressure required to balance these forces so that the casing will not hydraulic out of the hole (move upward) in psi:

$$P_b = \left(\frac{693}{140.5}\right) = 4.9 \text{ psi}$$

Step 8: Calculate the mud weight increase required to balance the pressure in lbm/gal:

$$W_{mb} = \left(\frac{\left(\frac{4.9}{0.052}\right)}{164}\right) = 0.57 \approx 0.6 \text{ lbm/gal}$$

Step 9: Calculate the new mud weight in lbm/gal:

$$W_{mn} = (8.8 + 0.6) = 9.4 \text{ lbm/gal}$$

Check the forces with the new mud weight:

a) $PG = (15.8 - 9.4)(0.052) = 0.3328$ psi
b) $DP = (0.3328)(164) = 54.58$ psi
c) $F_{up} = (140.5)(54.58) = 7668$ lb
d) $F_d = (7737 - 7668) = 69$ lb

2.7 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. Use a moderate pump rate to prevent forcing the plugging material through the washed out pipe.

$$D_{pwo1} = \left(\frac{(C_r)(O_p)}{V_{pc}}\right) \tag{2.71}$$

Where: D_{pwo1} = depth of pipe washout in ft
C_r = strokes required for the pump pressure to increase
O_p = pump output in bbl
V_{pc} = capacity of drill pipe in bbl/ft

Example: Drill pipe = 3½ in.—13.3 lb/ft
DP capacity = 0.00742 bbl/ft
Pump output = 0.112 bbl/stk (5½ in. × 14 in. duplex @ 90% efficiency)

NOTE: A pressure increase was noted after 360 strokes.

$$D_{pwo1} = \left(\frac{(360)(0.112)}{0.00742}\right) = 5434 \text{ ft}$$

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, uncooked rice, corn starch, glass or plastic beads, brightly colored paint, and so on. In nonaqueous fluids, use a red dye designed for use to identify cement spacers.

$$D_{pwo2} = \left(\frac{(C_r)(O_p)}{(V_{pc} + V_{acb})}\right) \tag{2.72}$$

Where: D_{pwo2} = depth of pipe washout in ft
V_{acb} = capacity of the annulus between the open hole or casing in bbl/ft

Example: Drill pipe = 3½ in.—13.3 lb/ft
Drill pipe capacity = 0.00742 bbl/ft
Pump output = 0.112 bbl/stk (5½ in. × 14 in. duplex @ 90% efficiency)
Annulus hole size = 8½ in.
Annulus capacity = 0.0583 bbl/ft (8½ in. × 3½ in.)

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

$$D_{pwo2} = \left(\frac{(2680)(0.112)}{(0.00742 + 0.0583)}\right) = 4569 \text{ ft}$$

2.8 Lost Returns—Loss of Overbalance

Step 1: Calculate the number of feet of fluid (water for WBM; base oil for OBM/SBM) added to the top of the annulus:

$$L_f = \frac{V_f}{9.71 \times 10^{-4}\left(D_h{}^2 - D_p{}^2\right)} \tag{2.73}$$

Where: L_f = length of fluid added to the top of the annulus in ft
V_f = volume of fluid added to the top of the annulus in bbl

Step 2: Calculate the reduction in bottomhole pressure (BHP) due to the unweighted fluid added to the top of the annulus:

$$P_{BHP} = (L_f)(W_{ma} - W_f)(0.052) \tag{2.74}$$

Where: P_{BHP} = decrease in bottom hole pressure in psi
W_{ma} = weight of mud in annulus in lbm/gal
W_f = weight of fluid added to the top of the annulus in lbm/gal

Step 3: Calculate the equivalent mud weight at TVD due to fluid added to the top of the annulus:

$$W_{me} = W_m - \left(\frac{\left(\frac{P_{BHP}}{0.052}\right)}{D_{TV}}\right) \tag{2.75}$$

Where: W_{me} = equivalent mud weight in lbm/gal
D_{TV} = total vertical depth in ft

Example: Calculate the equivalent mud weight due to the addition of unweighted fluid to the top of the annulus with the following data:

Mud weight	= 12.5 lbm/gal
Water added	= 150 bbl (required to fill the annulus)
Weight of water	= 8.33 lbm/gal
TVD	= 10,000 ft
Riser ID	= 18¾ in.
Drill pipe size	= 6⅝ × 5.965 in.

Step 1: Calculate the length of annulus covered by the volume of water added:

$$L_f = \frac{325}{9.71 \times 10^{-4}(18.75^2 - 6.625^2)} = 1087.9 \approx 1088 \text{ ft}$$

Step 2: Calculate the reduction in bottom hole pressure:

$$P_{BHP} = (1088)(12.5 - 8.55)(0.052) = 223.5 \approx 224 \text{ psi}$$

Step 3: Calculate the equivalent mud weight at the TVD:

$$W_{me} = 12.5 - \left(\frac{\left(\frac{224}{0.052}\right)}{10{,}000}\right) = 12.07 \text{ lbm/gal}$$

2.9 Stuck Pipe Calculations

2.9.1 Determine the Length of Free Pipe in Feet 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 using the data in the drill pipe stretch Table 2-3 shown below with the following formula.

$$P_{f1} = \frac{(P_{dps})(K_{fpt})}{F_p} \tag{2.76}$$

Table 2-4
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
2⅜	4.85	1.995	1.304	0.30675	3260.0
	6.65	1.815	1.843	0.21704	4607.7
2⅞	6.85	2.241	1.812	0.22075	4530.0
	10.40	2.151	2.858	0.13996	7145.0
3½	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	11.85	3.476	3.077	0.13000	7692.5
	14.00	3.340	3.805	0.10512	9512.5
4½	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	16.25	4.408	4.374	0.09145	10935.0
	19.50	4.276	5.275	0.07583	13187.5
5½	21.90	4.778	5.828	0.06863	14570.0
	24.70	4.670	6.630	0.06033	16575.0
6⅝	25.20	5.965	6.526	0.06129	16315.0

Where: P_{fl} = length of free pipe in ft
P_{dps} = drill pipe stretch in inches
K_{fpt} = free point constant from Table 2-4
F_p = pull force in 1000 lb

Example: Calculate the length of free drill pipe with the following data:

Drill pipe = 6.625 in.—25.2 lb/ft (S-135)
Stretch = 20 inches
Pull force = 35,000 lb

Step 1: Determine the drill pipe stretch from Table 2-4:

$K_{fpt} = 16315.0$

Step 2: Calculate the length of free pipe:

$$P_{f1} = \frac{(34)(16315.0)}{35} = 15{,}849 \text{ ft}$$

Method 2

Calculate the free point constant (K_{fpc}). The free point constant can be calculated for any type of steel drill pipe if the outside diameter (OD, in.) and inside diameter (ID, in.) are known:

Step 1: Calculate the cross-sectional area of the drill pipe wall in sq. in.:

$$A_s = \left(D_p{}^2 - D_i{}^2\right)(0.7854) \tag{2.77}$$

Where: A_s = cross-sectional area of the pipe wall in sq. in.
D_p = outside diameter of drill pipe in inches
D_i = inside diameter of drill pipe in inches

Step 2: Calculate the free point constant for the drill pipe:

$$K_{fpc} = (A_s)(2500) \tag{2.78}$$

Where: K_{fpc} = calculated free point constant

Example 1: Calculate the free point constant with the following data:

Drill pipe size and weight = 6.625 × 5.965 in.—25.2 lb/ft

Step 1: Calculate the cross sectional area:

$$A_s = (6.625^2 - 5.965^2)(0.7854) = 6.53 \text{ in.}^2$$

Step 2: Calculate the free point constant:

$$K_{fpc} = (6.53)(2500) = 16{,}325$$

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

Tubing size and weight $= 2.375 \times 2.441$ in.—6.5 lb/ft
Stretch $= 25$ in.
Pull force $= 20{,}000$ lb

Step 1: Calculate the cross-sectional area:

$$A_s = (2.375^2 - 1.815^2)(0.7854) = 1.843 \text{ in.}^2$$

Step 2: Calculate the free point constant:

$$K_{fpc} = (1.843)(2500) = 4607.5$$

Step 3: Calculate the depth of the stuck pipe:

$$P_{f1} = \frac{(25)(4607.5)}{20} = 5759 \text{ ft}$$

Method 3

This method of calculating the length of free pipe does not use the free point constant listed in Table 2-4.

Step 1: Calculate the weight of the drill pipe tube without the tool joints in lb/ft:

$$W_{dpt} = (2.67)\left(D_p{}^2 - D_i{}^2\right) \tag{2.79}$$

Where: W_{dpt} = weight of drill pipe tube in lb/ft

Step 2: Calculate the length of free pipe in ft:

$$P_{f2} = \frac{(735{,}294)(P_{dps})(W_{dpt})}{F_{pd}} \tag{2.80}$$

Where: P_{f2} = length of free pipe in ft
P_{dps} = pipe stretch from Table 2-2 in inches
W_{dpt} = weight of drill pipe tube in lb/ft (excluding tool joints)
F_{pd} = differential pull force in lb

NOTE: The weight of the drill pipe tube without the tool joints may be used if known instead of the calculated value.

Example: Calculate the length of free pipe using the following data:

Drill pipe size	$= 5.0 \times 4.276$ in. (19.5 lb/ft)
Stretch of pipe	$= 24$ in.
Differential pull force to obtain stretch	$= 30{,}000$ lb

Step 1: Calculate the weight of the drill pipe tube:

$$W_{dpt} = (2.67)(5.0^2 - 4.276^2) = 17.93 \text{ lb/ft}$$

Step 2: Calculate the length of free pipe:

$$P_{f2} = \frac{(735{,}294)(24)(17.93)}{30{,}000} = 10{,}547 \text{ ft}$$

2.10 Calculations Required for Placing Spotting Pills in an Open Hole Annulus

2.10.1 Calculate the Amount of Spotting Fluid Pill in Barrels Required to Cover the Stuck Point of the Drill String or Casing, and Then Calculate the Number of Pump Strokes Required to Spot the Pill

Step 1: Calculate the hole "washout" size in inches:

$$D_{hwo} = ((D_{bit})(H_{wo})) + D_{bit} \tag{2.81}$$

Where: D_{hwo} = diameter of hole "washout" in inches
D_{bit} = diameter of bit in inches
H_{wo} = hole "washout" factor in percent

Step 2: Calculate the annular volume for the drill pipe (or HWDP) and drill collars in bbl/ft (from equation (2.2)):

$$V_{ac} = \frac{\left(D_{hwo}{}^2 - D_p{}^2\right)}{1029.4} \tag{2.82}$$

Where: V_{ac} = annular capacity in bbl/ft
D_p = outside diameter of drill pipe, HWDP, or drill collars in inches

Step 3: Calculate the volume of the spotting fluid pill required for the annulus in bbl:

$$V_{sfpa} = (V_a)(L_{sfpa}) \tag{2.83}$$

Where: V_{sfpa} = volume of spotting fluid pill the annulus in bbl
L_{sfpa} = length of spotting fluid pill in annulus in ft

Step 4: Calculate the total volume of the spotting fluid pill required to cover the fish in bbl:

$$V_{sfpt} = V_{sfpa} + V_{sfpds} \tag{2.84}$$

Where: V_{sfpt} = total volume of spotting fluid pill required in bbl
V_{sfpds} = predetermined volume of spotting fluid pill to be left inside drill string in bbl

Step 5: Calculate the drill string capacity for each pipe section in bbl (from equation (2.5)):

$$V_p = \left(\frac{D_i^2}{1029.4}\right)(L_s)$$

Where: V_p = volume of drill pipe, HWDP, or drill collar section in bbl
D_i = inside diameter (ID) of drill pipe, HWDP, or drill collars in inches
L_s = length of drill pipe, HWDP, or drill collar section in ft

Step 6: Calculate the strokes required to pump the spotting fluid pill:

$$C_{sfp} = \frac{V_{sfpt}}{O_p} \tag{2.85}$$

Where: C_{sfp} = strokes to pump spotting fluid pill
O_p = pump output in bbl/stk

Step 7: Calculate the volume required to chase the spotting fluid pill in bbl:

$$V_{csfp} = (V_{ds} - V_{sfpds}) \tag{2.86}$$

Where: V_{csfp} = volume required to chase the spotting fluid in bbl
V_{ds} = volume of drill string in bbl
V_{sfpds} = volume of spotting fluid pill left in drill string in bbl

Step 8: Calculate the pump strokes required to chase the spotting fluid pill:

$$C_{csfp} = \left(\frac{V_{csfp}}{O_p}\right) + C_{ss} \tag{2.87}$$

Where: C_{csfp} = strokes required to chase the spotting fluid
C_{ss} = strokes required to pump spotting fluid through surface system

Step 9: Calculate the total strokes to spot the pill:

$$C_{sfpt} = C_{sfp} + C_{csfp} \tag{2.88}$$

Where: C_{sfpt} = total strokes to spot the pill

Example: The drill collars are differentially stuck. Use the following data to spot a base oil pill around the drill collars plus 200 feet (optional) above the collars and leave 30 barrels in the drill string:

Well depth (MD) = 10,000 ft
Hole diameter = 8½ in.
Washout factor = 20%
Drill pipe = 5.0 in.—19.5 lb/ft
  capacity = 0.0178 bbl/ft
  length = 9400 ft
Drill collar = 6½ × 2½ in.
  capacity = 0.0061 bbl/ft
  length = 600 ft

Pump output $= 0.117$ bbl/stk
Surface system $= 80$ stk (strokes required to pump the pill to the drill string)

Step 1: Calculate the hole "washout" size in inches:

$$D_{hwo} = ((8.5)(0.20)) + 8.5 = 10.2 \text{ in.}$$

Step 2: Calculate the annular volume for the drill pipe and drill collars:

a) Annular capacity around the drill collars:

$$V_{adc} = \frac{(10.2^2 - 6.5^2)}{1029.4} = 0.0600 \text{ bbl/ft}$$

b) Annular capacity around the drill pipe:

$$V_{adp} = \frac{(10.2^2 - 5.0^2)}{1029.4} = 0.0768 \text{ bbl/ft}$$

Step 3: Calculate the total volume of pill required in the annulus:

a) Volume opposite the drill collars:

$$V = (0.0600)(600) = 36 \text{ bbl}$$

b) Volume opposite the drill pipe:

$$V = (0.0768)(200) = 15.4 \text{ bbl}$$

c) Total volume, bbl, required in the annulus:

$$V = 36 + 15.4 = 51.4 \text{ bbl}$$

Step 4: Calculate the total volume required for the spotting fluid pill:

$$V_t = 51.4 + 30 = 81.4 \text{ bbl} \approx 81 \text{ bbl}$$

Step 5: Calculate the drill string capacity:

a) Drill collar capacity in bbl:

$$V_{dc} = (0.0061)(600) = 3.7 \text{ bbl}$$

b) Drill pipe capacity in bbl:

$$V_{dp} = (0.0178)(9400) = 167.3 \text{ bbl}$$

c) Total drill string capacity in bbl:

$$V_{tds} = 3.7 + 167.3 = 171 \text{ bbl}$$

Step 6: Calculate the strokes required to pump the pill:

$$C_{sfp} = \frac{81}{0.117} = 692 \text{ stk}$$

Step 7: Calculate the volume required to chase the spotting fluid pill:

$$V_{csfp} = (171 - 30) = 141 \text{ bbl}$$

Step 8: Calculate the strokes required to chase the pill:

$$C_{csfp} = \left(\frac{141}{0.117}\right) + 80 = 1285 \text{ stk}$$

Step 9: Calculate the strokes required to spot the pill:

$$C_{sfpt} = 692 + 1285 = 1977 \text{ stk}$$

2.10.2 Determine the Length of an Unweighted Spotting Fluid Pill That Will Balance Formation Pressure in the Annulus in Feet

Step 1: Calculate the difference in pressure gradient between the mud weight and the spotting fluid pill in psi/ft:

$$G_{sfp} = (W_m - W_{sfp})(0.052) \tag{2.89}$$

Where: G_{sfp} = difference in pressure gradient in psi/ft
W_m = weight of mud in lbm/gal
W_{sfp} = weight of spotting fluid pill in lbm/gal

Step 2: Calculate the length of an unweighted spotting fluid pill that will balance formation pressure in the annulus:

$$L_{sfp} = \frac{OB}{G_{sfp}} \tag{2.90}$$

Where: L_{sfp} = length of unweighted spotting fluid pill in ft
OB = overbalance pressure needed to control pore pressure in psi

Example: Use the following data to determine the length of an unweighted spotting fluid pill that will balance formation pressure in the annulus:

Mud weight	= 11.2 lbm/gal
Weight of spotting fluid pill	= 6.7 lbm/gal (Diesel = 7.0 lbm/gal/ Synthetic = 6.7 lbm/gal)
Amount of overbalance	= 250.0 psi

Step 1: Calculate the difference in pressure gradient in psi/ft:

$$G_{sfp} = (11.2 - 6.7)(0.052) = 0.234 \text{ psi/ft}$$

Step 2: Calculate the length of an unweighted spotting fluid pill that will balance formation pressure in the annulus:

$$L_{sfp} = \frac{250}{0.234} = 1068 \text{ ft}$$

Therefore: Less than 1068 ft of an unweighted spotting fluid pill should be used to maintain a safe balance of the formation pore pressure and prevent an influx that would cause a kick or blowout.

2.11 Pressure Required to Break Circulation

2.11.1 Pressure Required to Break the Mud's Gel Strength inside the Drill String in psi

Step 1: Calculate the pressure required to break the mud's gel strength inside the drill string:

$$P_{gsds} = \left(\frac{(L_{ds})(\tau_{gs})}{300\, D_i}\right) \tag{2.91}$$

Where: P_{gsds} = pressure required to break gel strength inside the drill string in psi
τ_{gs} = 10 min gel strength of drilling fluid in lb/100 ft^2
D_i = inside diameter of drill pipe in inches
L_{ds} = length of drill string in ft

Step 2: Calculate the pressure required to break the mud's gel strength in the annulus:

$$P_{gsa} = \left(\frac{(L_{ds})(\tau_{gs})}{300(D_h - D_i)}\right) \tag{2.92}$$

Where: P_{gsa} = pressure required to break gel strength in the annulus in psi
D_h = diameter of the annulus in inches

Step 3: Calculate the total pressure required to break circulation:

$$P_{gst} = (P_{gsds} + P_{gsa}) \tag{2.93}$$

Where: P_{gst} = pressure required to break circulation in the well in psi

Example: Calculate the pressure required to break circulation in the well with this data:

Gel strength (10 or 30 minute) = 18 lb/100 ft^2
Drill string = 6⅝ × 5.965 in.
Hole size = 12¼ in.
Depth (MD) = 15,000 ft

Step 1: Calculate the pressure required to break the mud's gel strength inside the drill string:

$$P_{gsds} = \left(\frac{(15{,}000)(18)}{300(5.965)}\right) = 150.9 \approx 151.0 \text{ psi}$$

Step 2: Calculate the pressure required to break the mud's gel strength in the annulus:

$$P_{gsa} = \left(\frac{(15{,}000)(18)}{300(12.25 - 6.625)}\right) = 160 \text{ psi}$$

Step 3: Calculate the total pressure required to break circulation:

$P_{gst} = (151 + 160) = 311$ psi

2.11.2 Calculate the Effective Gel Strength Based on the Actual Pressure Required to Break the Circulation

$$\tau_{egs} = \frac{300(P_{bc})(D_i(D_h - D_{ds}))}{(L_{ds})(D_i + D_h - D_{ds})} \tag{2.94}$$

Where: τ_{egs} = effective gel strength based on pressure required to break circulation in lb/100 ft^2
P_{bc} = actual pressure required to break circulation in the well in psi

Example: Calculate the effective gel strength with the following data:

Pressure required to break circulation	= 475 psi
Drill string length	= 15,000 ft
Hole size	= 12¼ in.
Drill string size	= 6⅝ × 5.965 in.

$$\tau_{egs} = \frac{300(475)(5.965(12.25 - 6.625))}{(15{,}000)(5.965 + 12.25 - 6.625)} = 27.5 \text{ lb/100 ft}^2$$

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CHAPTER THREE

DRILLING FLUIDS

Symbol	Description	Units
A	additive content	lb/bbl
$B_{\%}$	amount of bentonite in the mud	%
B_{ppb}	amount of bentonite in the mud	lb/bbl
C_D	volume of dilution	gal/min
C_F	volume of mud feed into centrifuge	gal/min
Cl	chloride content measured from the filtrate	ppm
C_O	centrifuge overflow mud weight	ppg
C_{OM}	volume fraction of mud in underflow	%
C_U	centrifuge underflow volume	gal/min
C_{UA}	mud additives in the underflow going into the mixing pit	lb/min
C_{UB}	amount of weight material going into the mixing pit	lb/min
C_{UC}	amount of clay in the centrifuge underflow	lb/min
C_{UL}	volume of base liquid flow rate going into the mixing pit	gal/min
$DS_{\%}$	volume of drill solids	%
DS_{ppb}	amount of drill solids	lb/bbl
F_{CEC}	CEC of the formation solids	lb/bbl
f_o	fraction of base oil in mixture	decimal
f_w	fraction of water in mixture	decimal
HGS	volume of high specific gravity weight material	%
HGS_{ppb}	amount of high specific gravity weight material	lb/bbl
H_s	volume fraction of solids discarded by the hydrocyclone	decimal
L_b	base liquid mud weight	ppg
LGS	volume of LGS	%
LGS_a	low gravity solids from bentonite or chemicals added to the mud	%
LGS_{ppb}	amount of LGS	lb/bbl
LGS_{RM}	maximum recommended low gravity solids fractions	% vol
M_{MBT}	MBT of the mud	lb/bbl
MW	mud weight	ppg
MW_D	mud weight of dilution liquid	ppg
MW_{MX}	maximum mud weight possible with weight material inventory	ppg
MW_U	mud weight of underflow	ppg
MW_X	mud weight of weight material-base liquid mixture	ppg
$O_{\%}$	oil content in the mud	%
O_a	volume of oil to be added	bbl
O_{ASG}	specific gravity of base oil being used in mud	gm/cc

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Symbol	Description	Units
O_n	new oil content	decimal
O_o	old oil content in 100 bbl of mud	bbl
O_{OWR}	oil content in the OWR	%
S_{ASG}	average specific gravity of suspended solids in the mud	gm/cc
S_{fASG}	average specific gravity of solids without salt in the water phase	gm/cc
SG_{wm}	specific gravity of weight material	gm/cc
S_{MR}	mass rate of solids discharged by one cone of a hydrocyclone	lb/hr
S_{RM}	maximum recommended solids content	% vol
S_s	volume of suspended solids	%
t	time required to collect sample slurry	sec
V_1	volume of fluid 1	bbls, gals
V_2	volume of fluid 2	bbls, gals
V_a	volume of base liquid added to reduce the mud weight	bbls
V_C	current total volume of mud system	bbls
V_d	volume of mud to be dumped out of the system to make room for the mud weight increase	bbls
V_{dm}	volume of dilution with base liquid or mud	bbls
V_{dmr}	volume of mud in to be jetted and base liquid or slurry to be added to maintain constant circulating volume	bbls
V_f	final volume	bbls, gals
V_H	volume of liquid ejected by one cone of a hydrocyclone	gal/hr
V_i	volume increase	bbls
V_{no}	new volume of base oil-water mixture in when holding the base oil content constant	bbls
V_{ns}	new starting volume for limited weight material inventory	bbls
V_{nw}	new volume of base oil-water mixture in when holding the water content constant	bbls
V_o	old volume of base oil-water mixture	bbls
V_Q	volume of slurry collected	qt
V_s	starting volume of mud	bbls
V_{wL}	volume of base liquid required to wet weight material added to increase the mud weight	bbls
V_{WM}	volume of weight material	bbls
$W_{\%}$	water content in the mud	%
$W_{\%}$	volume of water in mud from the retort	%
W_a	volume of water to be added	bbls
W_{ASG}	average specific gravity of the salt water	gm/cc
W_M	number of sacks of weight material required for 100 bbl of mud	100 lb sk
W_{Mm}	weight material required	kg/m^3
W_{Ma}	weight material in adjusted for the desired final volume	100 lb sks
W_{MI}	weight material inventory on rig	100 lb sks

Symbol	Description	Units
W_{MX}	weight material required for the mixture	100 lb sks
W_n	new water content	decimal
W_o	old water content in 100 bbl of mud	bbls
W_s	volume of salt water	%
ρ_1	mud weight of fluid 1	ppg, lb/ft^3
ρ_2	mud weight of fluid 2	ppg, lb/ft^3
ρ_{bo}	mud weight of base oil	ppg
ρ_f	final mud weight	ppg, lb/ft^3
ρ_n	new mud weight	ppg
ρ_o	original mud weight	ppg
ρ_w	mud weight of water	ppg

3.0 Mud Density Increase and Volume Change

3.0.1 Increase Mud Density with *No* Base Liquid Added and *No* Volume Limit

Various dry materials may be used to increase the density of drilling, completion, and workover fluids. Those materials may include barite, hematite, calcium carbonate, magnesium carbonate, various dry salts (for example, sodium, calcium, zinc chloride, and/or sodium formate), and blends. It is important to know the average specific gravity (ASG) of the material being used. For example, the current API ASG specification for barite is 4.2.[1] The ASG of the dry material you are using should be obtained from the company supplying the product.

a) Short formula for mud weight increase:

$$W_M = 5(\rho_n)(\rho_n - \rho_o) \tag{3.1}$$

Where: W_M = number of 100 lb sacks of weight material required for 100 bbls of mud
ρ_o = original mud weight in ppg
ρ_n = new mud weight in ppg

b) Volume increase based on the amount of weight material:

$$V_i = \frac{W_M}{3.5(SG_{wm})} \tag{3.2}$$

Where: V_i = volume increase in bbls
SG_{wm} = specific gravity of weight material

Example: Calculate the number of sacks of 4.2 ASG of barite required to increase the density of 100 bbls of 12.0 ppg (ρ_o) mud to 14.0 ppg (ρ_n) and the resultant volume increase:

$W_M = 5(14.0)(14.0 - 12.0)$
$W_M = 140$ sacks of barite required for 100 bbls of 12.0 ppg mud

$$V_i = \frac{140}{3.5(4.2)}$$

$V_i = 9.5$ bbls volume increase

c) Increase mud weight:

$$W_M = \frac{(350\ SG_{wm})(\rho_n - \rho_o)}{(8.34\ SG_{wm}) - \rho_n} \tag{3.3}$$

Where: 350 = weight of 1 barrel of fresh water in lbs
8.34 = mud weight of fresh water in lb/gal (ppg)
SG_{wm} = specific gravity of weight material, gm/cc

d) Volume increase with 100 lb sacks of weight material based on the change in mud weight:

$$V_i = \frac{100(\rho_n - \rho_o)}{(8.34\ SG_{wm}) - \rho_n} \tag{3.4}$$

Where: V_i = volume increase in bbls

Example: Calculate the number of sacks of 4.2 ASG barite required to increase the density of 100 barrels of 12.0 ppg (ρ_o) mud to 14.0 ppg (ρ_n):

$$W_M = \frac{(350(4.2))(14.0 - 12.0)}{(8.34(4.2)) - 14.0}$$

$$W_M = \frac{(1470)(2.0)}{(35.0 - 14.0)} = \frac{2940}{21.0}$$

W_M required = 140 sk of barite per 100 bbl of 12.0 ppg mud

$$V_i = \frac{100(14.0 - 12.0)}{(8.34(4.2)) - 14.0}$$

$$V_i = \frac{200}{21.0}$$

V_i = 9.5 bbls volume increase

3.0.2 Increase Mud Weight with *No* Base Liquid Added *but* Limit Final Volume

Step 1: Calculate the starting volume required:

$$V_s = \frac{(8.34\ SG_{wm}) - \rho_n}{(8.34\ SG_{wm}) - \rho_o}(V_f) \tag{3.5}$$

Where: V_s = starting volume of mud in bbls
V_f = final volume of mud in bbls

Step 2: Calculate the amount of weight material to be added:

$$W_{Ma} = (V_f - V_s)(SG_{wm})(350) \tag{3.6}$$

Where: W_{Ma} = weight material in 100 lb sacks adjusted for the desired final volume

Example: Calculate the number of sacks of 4.2 ASG barite required to increase the density of 12.0 ppg (ρ_o) mud to end up with 100 bbls of 14.0 ppg (ρ_n) mud:

$$V_s = \frac{(8.34(4.2)) - 14.0}{(8.34(4.2)) - 12.0}(100)$$

$$V_s = 0.91(100)$$

V_s = starting volume is 91 bbls

$$W_{Ma} = (100 - 91)(4.2)(3.5)$$

W_{Ma} = 132 sacks of barite added to 91 bbls of 12.0 ppg mud to result in 100 bbls of 14.0 ppg mud

3.0.3 Increase the Mud Density *with* Base Liquid Added and *No* Volume Limit

Adding dry powder to a mud will cause an increase in the viscosity of that mud. It is a general rule that a volume of base liquid must be added to wet the surface of any dry weight material added to an existing mud. From experience, at least 1½ gallons of base liquid must be added per 100 lbs of weight material added.[6] This base liquid volume has to be "weighed up" to the final mud weight required for the total mud system. Therefore, the amount of weight material calculated with the previous equations is the minimum amount that would be required before adding the additional base liquid. The following equations can be used to calculate the amount of base liquid to be added to the amount of weighting material to reach the desired mud weight.

Step 1: Calculate the mud weight of the weight material-base liquid mixture:

$$MW_X = \frac{(8.34\ SG_{wm}) + (0.1251\ SG_{wm}(L_b))}{1 + (0.1251\ SG_{wm})} \qquad (3.7)$$

Where: MW_X = mud weight of weight material-base liquid mixture in ppg
L_b = base liquid mud weight in ppg

Step 2: Calculate the amount of weight material required:

$$W_{MX} = \frac{(0.42\ MW_X)(\rho_n - \rho_o)}{(MW_X - \rho_n)(1 + (0.015\ L_b))}(V_s) \qquad (3.8)$$

Where: W_{MX} = number of 100 lb sacks of weight material required for the mixture

Step 3: Calculate the final volume with the weight material-base liquid mixture added:

$$V_f = V_s\left[1 + \left(\frac{MW_M}{350\ SG_{wm}}\right) + \left(\frac{1.5\ MW_M}{4200}\right)\right] \tag{3.9}$$

Where: V_f = final volume of mud in bbls
V_s = starting volume of mud in bbls

Example: Calculate the number of sacks of 4.2 ASG barite required to increase the density of 100 bbls of 12.0 ppg (ρ_o) mud to 14.0 ppg (ρ_n) using fresh water as the wetting agent:

$$MW_X = \frac{(8.34(4.2)) + (0.1251(4.2)(8.34))}{1 + (0.1251(4.2))}$$

$$MW_X = \frac{(35) + (4.38)}{1 + (0.525)}$$

MW_X = 25.8 ppg, the mud weight of the weight material-fresh water mixture

$$W_{MX} = \frac{(0.42(25.8))(14.0 - 12.0)}{(25.8 - 14.0)(1 + (0.015(8.34)))}(100)$$

$$W_{MX} = \frac{21.67}{13.27}(100)$$

W_{MX} = 163 sacks of weight material required for 100 bbls of 12.0 ppg mud

$$V_f = 100\left[1 + \left(\frac{25.8}{350(4.2)}\right) + \left(\frac{1.5(25.8)}{4200}\right)\right]$$

$$V_f = 100[1 + (0.11088) + (0.0582)]$$

V_f = 116.9 bbls final volume of 14.0 ppg mud

3.0.4 Increase Mud Weight *with* Base Liquid Added *but* Limit Final Volume

Step 1: Calculate the starting volume of mud required to obtain the desired final mud volume:

$$V_s = \frac{V_f}{\left(1 + \left(\frac{W_{MX}}{350\ SG_{wm}} + \frac{1.5\ W_{MX}}{4200}\right)\right)} \tag{3.10}$$

Step 2: Calculate the amount of mud that must be dumped to have available pit space for the final volume in the system:

$$V_d = V_f - V_s \tag{3.11}$$

Where: V_d = volume of mud in bbls to be dumped out of the system to make room for the mud weight increase

Step 3: Calculate the amount of base liquid added to wet the weight material:

$$V_{wL} = V_f - (V_s + V_i) \tag{3.12}$$

Where: V_{wL} = volume of base liquid in bbls required to wet weight material added to increase the mud weight

Example: Calculate the amount of mud to be dumped when increasing the mud weight from 12.0 ppg to 14.0 ppg with a final volume of 1000 bbls:

$$V_s = \frac{1000}{\left(1 + \left(\frac{25.8}{350(4.2)} + \frac{1.5(25.8)}{4200}\right)\right)}$$

$$V_s = \frac{1000}{(1 + (0.11088) + (0.0582))}$$

V_s = 855 bbls starting volume for increasing the mud weight with a limited final volume

$$V_d = 1000 - 855$$

$V_d = 145$ bbls of 12.0 ppg mud must be dumped before increasing the mud weight to 14.0 ppg with a system volume limited to 1000 bbls

$$W_{MX} = \frac{(0.42(25.8))(14.0 - 12.0)}{(25.8 - 14.0)(1 + (0.015(8.34)))}(855)$$

$$W_{MX} = \frac{21.67}{13.28}(855)$$

$W_{MX} = 1395$ sacks of barite required for mud weight increase

$$V_i = \frac{1395}{3.5(4.2)}$$

$V_i = 95$ bbl volume of barite required for mud weight increase

$$V_{wL} = 1000 - (855 + 95)$$

$V_{wL} = 50$ bbls of base liquid required for wetting the barite weight material

3.0.5 Increase Mud Weight *with* Base Liquid Added *but* Limit Final Volume and *Limited* Weight Material Inventory

Step 1: Calculate the amount of weight material-base liquid (W_{MX}) required to increase the mud weight of the total mud system volume:

$$W_{MX} = \frac{(0.42\ MW_X)(\rho_n - \rho_o)}{(MW_X - \rho_n)(1 + (0.015\ L_b))}(V_C) \tag{3.13}$$

Where: V_C = current total volume of mud system in bbls

If this amount of weight material required is more than the current inventory, then a new starting volume must be calculated.

Step 2: Calculate the new starting volume for the weight material inventory on the rig:

$$V_{ns} = \left(\frac{W_{MI}}{W_{MX}}\right) V_C \tag{3.14}$$

Where: V_{ns} = new starting volume for limited weight material inventory in bbls
W_{MI} = weight material inventory on rig in 100 lb sacks

Step 3: Recalculate the amount of weight material-base liquid (W_{MX}) required to increase the mud weight of the new starting mud system volume:

$$W_{MX} = \frac{(0.42\ MW_X)(\rho_n - \rho_o)}{(MW_X - \rho_n)(1 + (0.015\ L_b))}(V_{ns}) \tag{3.15}$$

Example: Calculate the amount of weight material required to increase the mud weight from 12.0 ppg to 14.0 ppg with a limited mud volume and the following data:

Current mud volume	1000 bbls
Maximum mud volume	1000 bbls
Weight material inventory	1400 sacks

$$W_{MX} = \frac{(0.42(25.8))(14.0 - 12.0)}{(25.8 - 14.0)(1 + (0.015(8.34)))}(1000)$$

$$W_{MX} = \frac{21.67}{13.28}(1000)$$

W_{MX} = 1631.8 or 1632 sacks required to increase the density of 1000 bbls of mud

$$V_{ns} = \left(\frac{1400}{1632}\right) 1000$$

V_{ns} = 857.8 or 858 bbls of new starting mud volume in bbls

$$W_{MX} = \frac{(0.42(25.8))(14.0 - 12.0)}{(25.8 - 14.0)(1 + (0.015(8.34)))}(858)$$

$$W_{MX} = \frac{21.67}{13.28}(858)$$

W_{MX} = 1400 sacks required to increase the mud weight of the new starting volume with limited weight material inventory

3.0.6 Increase Mud Weight to a Maximum Mud Weight *with* Base Liquid Added *but* with *Limited* Weight Material Inventory

$$MW_{MX} = \frac{((100\,W_{MI})(MW_X)(1 + (0.015\,L_b))) + (42(MW_X)(V_s)(\rho_o))}{((100\,W_{MI})(1 + (0.015\,L_b))) + (42(MW_X)(V_s))} \tag{3.16}$$

Where: MW_{MX} = Maximum mud weight possible in ppg with weight material inventory

Example: Calculate the maximum mud weight with the following data:

Mud system volume	2000 bbls
Current mud weight	12.0 ppg
Weight material-base liquid mixture weight	25.8 ppg
Base liquid mud weight	8.34 ppg
Weight material inventory	1000 sks

$$MW_{MX} = \frac{((100(1000))(25.8)(1 + (0.015(8.34)))) + (42(25.8)(2000)(12.0))}{((100(1000))(1 + (0.015(8.34)))) + (42(25.8)(2000))}$$

$$MW_{MX} = \frac{(2902500) + (26006400)}{(112500) + (2167200)}$$

$$MW_{MX} = \frac{28908900}{2279700} = 12.68 \approx 12.7\,\text{ppg}$$

is the maximum mud weight that can be mixed with only 1000 sacks of weight material in the rig inventory with a 2000 bbl system of 12.0 ppg mud.

3.0.7 SI Unit Calculation

$$W_{Mm} = \frac{(1000\ SG_{WM})(\rho_n - \rho_o)}{(1000\ SG_{WM}) - \rho_n} \tag{3.17}$$

Where: W_{Mm} = weight material required in kg/m^3
ρ_o = original mud weight in kg/m^3
ρ_n = new mud weight in kg/m^3

Example: Calculate the amount of 4.2 barite required to increase the mud density of 1 m^3 of mud volume from 1440 kg/m^3 to 1680 kg/m^3.

$$W_{Mm} = \frac{(1000(4.2))(1680 - 1440)}{1000(4.2) - 1680}$$

$$W_{Mm} = 400\ kg/m^3$$

3.1 Mud Weight Reduction with Base Liquid Dilution

3.1.1 Mud Weight Reduction with Base Liquid

$$V_a = \frac{V_m(\rho_o - \rho_n)}{\rho_n - L_b} \tag{3.18}$$

Where: V_a = volume of base liquid in bbls added to reduce the mud weight

Example: Determine the number of barrels of fresh water weighing 8.34 ppg required to reduce the mud weight of 100 bbls of water-base mud (WBM) from 14.0 ppg to 12.0 ppg:

$$V_a = \frac{100(14.0 - 12.0)}{12.0 - 8.33}$$

$$V_a = \frac{200}{3.67}$$

V_a = 54.5 bbls of water are required

Example: Determine the number of barrels of base oil weighing 6.7 ppg required to reduce the mud weight of 100 bbls of synthetic-base mud (SBM) from 14.0 ppg to 12.0 ppg:

$$V_a = \frac{100(14.0 - 12.0)}{12.0 - 6.7}$$

$$V_a = \frac{200}{5.3}$$

V_a = 37.7 bbls of base oil are required

NOTE: Adding this much base oil to 100 bbls of SBM may increase the oil/water ratio (OWR) too much, so the dilution volume may need to be added as a mixture of base oil and water with the same OWR as the active mud system. To calculate the volume of mixture required, calculate the mud weight of the mixture, and then calculate a new V_a value.

$$MW_X = (f_o(\rho_{bo})) + (f_w(\rho_w)) \qquad (3.19)$$

Where: f_o = fraction of base oil in mixture
ρ_{bo} = mud weight of base oil in ppg
f_w = fraction of water in mixture
ρ_w = mud weight of water in ppg

Example: Determine the mud weight of the base oil/water mixture required to reduce the mud weight of 100 bbls of synthetic-base mud (SBM) from 14.0 ppg to 12.0 ppg and maintain a 75/25 OWR:

Base oil mud weight: 6.7 ppg (SG 0.80)

$$MW_X = (0.75(6.7)) + (0.25(8.34))$$
$$MW_X = 0.75 \text{ ppg}$$

$$V_a = \frac{100(14.0 - 12.0)}{12.0 - 7.11}$$

$$V_a = \frac{200}{4.89}$$

V_a = 40.9 bbls

Therefore, (40.9(0.75)) or 30.7 bbls of base oil will be required to mix with (40.9(0.25)) or 10.2 bbls of water to reduce the mud weight and keep the OWR the same.

3.2 Mixing Fluids of Different Densities

3.2.1 The Material Balance Formula

$$V_f \rho_f = (V_1 \rho_1) + (V_2 \rho_2) \tag{3.20}$$

Where: V_f = final volume in bbls, gals, etc.
ρ_f = final mud weight in ppg, lb/ft^3, etc.
V_1 = volume of fluid 1 in bbls, gals, etc.
ρ_1 = mud weight of fluid 1 in ppg, lb/ft^3, etc.
V_2 = volume of fluid 2 in bbls, gals, etc.
ρ_2 = mud weight of fluid 2 in ppg, lb/ft^3, etc.

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:

$$\begin{aligned}
300(11.5) &= ((300 - x)11.0) + (14.0x) \\
3450 &= ((3300 - 11.0x)) + (14.0x) \\
3450 - 3300 &= 3.0x \\
150 &= 3.0x \\
x &= 50 \text{ bbls of 14.0 ppg mud} \\
300 - 50 &= 250 \text{ bbls of 11.0 ppg required}
\end{aligned}$$

To check the volumes are correct:

$$\begin{aligned}
300(11.5) &= (250(11.0)) + (50(14.0)) \\
3450 &= (2750) + (700) \\
3450 &= 3450
\end{aligned}$$

To check the final mud weight:

$$\begin{aligned}
300x &= (250(11.0)) + (50(14.0)) \\
300x &= (2750) + (700) \\
x &= \frac{3450}{300} = 11.5 \text{ ppg}
\end{aligned}$$

Example 2: No limit is placed on volume:

Determine the final mud weight when the following two muds are mixed together:

Given: 400 bbl of 11.0 ppg mud, and 400 bbl of 14.0 ppg mud

$$800\rho_f = (400(11.0)) + (400(14.0))$$

$$\rho_f = \frac{(4400) + (5600)}{800} = \frac{10000}{800}$$

$$\rho_f = 12.5 \text{ ppg}$$

3.3 Oil-Based Mud Calculations

3.3.1 Calculate the Starting Volume of Liquid (Base Oil plus Water) Required to Prepare a Desired Final Volume of Mud

Example: Prepare 100 bbls of 16.0 ppg mud with a 75/25 OWR using a 0.80 SG base oil and fresh water (no salt added):

a) Calculate the base oil-water mixture mud weight from equation (3.19):

$$MW_X = (0.75(6.7)) + (0.25(8.34)) = 7.1 \text{ ppg}$$

b) Calculate the starting volume using equation (3.5):

$$V_s = \frac{(8.34(4.2)) - 16.0}{(8.34(4.2)) - 7.1}(100)$$

$$V_s = \frac{19.0}{27.9}(100) = \text{68.1 bbls of a base oil-water mixture with an OWR of } 75/25$$

c) Calculate the volume of weight material in bbls:

$$V_{WM} = V_f - V_s \tag{3.21}$$

Where: V_{WM} = volume of weight material in bbls

d) Calculate the sacks of weight material required for the 100 bbl of mud:

$$W_M = V_{WM}(3.5(SG_{WM})) \tag{3.22}$$

Where: W_M = number of 100 lb sacks of weight material required for 100 bbls of mud

Continue the *Example*:

$$V_{WM} = 100 - 68.1 = 31.9 \text{ bbls of weight material}$$

$$V_M = 31.9((3.5)(4.2)) = 575 \text{ sacks of weight material}$$

3.3.2 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 (OWR) is calculated as follows:

a) Calculate the percent (%) of base oil in the OWR mixture:

$$O_{OWR} = \frac{O_{\%}}{(O_{\%} + W_{\%})} 100 \tag{3.23}$$

Where: O_{OWR} = oil content in the OWR in %
$O_{\%}$ = oil content in the mud in %
$W_{\%}$ = water content in the mud in %

b) Calculate the percent (%) of water in the OWR mixture:

$$W_{OWR} = \frac{W_{\%}}{(O_{\%} + W_{\%})} 100 \tag{3.24}$$

Example: Calculate the OWR of a mud that has the following data:

Oil content by volume	51%
Water content by volume	17%
Solids content by volume	32%

$$O_{OWR} = \frac{57}{(57+17)} 100 = 75$$

$$W_{OWR} = \frac{17}{(57+17)} 100 = 25$$

The OWR is 75/25.

3.3.3 Change the OWR

NOTE: If the OWR is to be *increased*, add oil; if it is to be *decreased*, add water.

a) To increase the oil content in the OWR, the current water content will be changed to a new volume percent in the OWR:

$$V_{nw} = \frac{W_o}{W_n} \tag{3.25}$$

Where: V_{nw} = new volume of base oil-water mixture in bbls when holding the water content constant
W_o = old water content, bbls in 100 bbls of mud
W_n = new water content in % (decimal)

b) The amount of oil to add is calculated by the following:

$$O_a = V_{nw} - V_o \tag{3.26}$$

Where: O_a = volume of oil to be added in bbls
V_o = old volume of base oil-water mixture in bbls

c) To increase the water content in the OWR, the current oil content will be changed to a new volume:

$$V_{no} = \frac{O_o}{O_n} \tag{3.27}$$

Where: V_{no} = new volume of base oil-water mixture in bbls when holding the base oil content constant
O_o = old oil content, bbls in 100 bbls of mud
O_n = new oil content in % (decimal)

d) The amount of water to add is calculated by the following:

$$W_a = V_{no} - V_o \tag{3.28}$$

Where: W_a = volume of water to be added in bbls

Example 1: Increase the OWR from 75/25 to 80/20:

Given:	Oil content by volume	51%
	Water content by volume	17%
	Solids content by volume	32%
	OWR	75/25

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 old liquid volume, but it will represent *only* 20% of the new liquid volume.

$$V_{nw} = \frac{17}{0.20}$$

V_{nw} = 85 bbls of new liquid volume after adding base oil to 100 bbls of mud volume

O_a = 85−68 = 17 bbls of base oil to be added per 100 bbls of mud

Check the calculations.

$$O_{OWR} = \frac{57 + 17}{(68 + 17)} 100 = 80$$

The new OWR is 80/20.

Example 2: Change the OWR from 75/25 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:

$$V_{no} = \frac{51}{0.70} = 72.8 \approx 73 \text{ bbls}$$

$W_a = 73 - 68 = 5$ bbls of water added per 100 bbls of mud

Check the calculations.

$$W_{OWR} = \frac{17 + 5}{(68 + 5)} 100 = 30$$

The new OWR is 70/30.

3.4 Solids Analysis

This section deals with 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: Calculate the volume of salt water in percent (%):

$$W_s = \left[(5.88 \times 10^{-8}\ Cl^{1.2}) + 1\right](W_{\%}) \tag{3.29}$$

Where: W_s = volume of salt water in percent (%)
Cl = chloride content measured from the filtrate in ppm
$W_{\%}$ = volume of water in mud from the retort in %

Step 2: Calculate the volume of the suspended solids in percent (%):

$$S_s = 100 - O_{\%} - W_s \tag{3.30}$$

Where: S_s = volume of suspended solids in %
$O_{\%}$ = oil content in %

Step 3: Calculate the average specific gravity (ASG) of the salt water:

$$W_{ASG} = \left[(1.94 \times 10^{-6})(Cl^{0.95})\right] + 1 \tag{3.31}$$

Where: W_{ASG} = average specific gravity of the salt water

Step 4: Calculate the average specific gravity of the solids suspended in the mud:

$$S_{ASG} = \frac{(12\ MW) - ((W_s)(W_{ASG})) - ((O_{\%})(O_{ASG}))}{S_s} \tag{3.32}$$

Where: S_{ASG} = average specific gravity of suspended solids in the mud
$O_{\%}$ = volume of oil in the mud in %
O_{ASG} = specific gravity of base oil being used in mud (0.84 for diesel; 0.80 for IO)

Step 5: Calculate the average specific gravity of solids *without* salt in the water phase:

$$S_{fASG} = \frac{(12\ MW) - (1W_{\%}) - ((O_{\%})(O_{ASG}))}{S_s} \tag{3.33}$$

Where: S_{fASG} = average specific gravity of solids without salt in the water phase

Step 6: Calculate the volume of low gravity solids (LGS) in percent (%):

$$LGS = \frac{(S_s)(WM_{SG} - S_{ASG})}{1.6} \tag{3.34}$$

Where: LGS = volume of LGS in %

Step 7: Calculate the amount of LGS in lb/bbl:

$$LGS_{ppb} = 9.1\ LGS \tag{3.35}$$

Where: LGS_{ppb} = amount of LGS in lb/bbl

Step 8: Calculate the volume of the weight material in percent (%):

$$HGS = S_s - LGS \tag{3.36}$$

Where: HGS = volume of high specific gravity weight material in %

Step 9: Calculate the amount of high specific gravity weight material in pounds (lbs):

$$HGS_{ppb} = HGS(3.5(SG_{WM})) \tag{3.37}$$

Where: HGS_{ppb} = amount of high specific gravity weight material in lb/bbl

Step 10: Calculate the amount of bentonite (high-quality LGS) in the mud:

If the cation exchange capacity (CEC) of the formation clays and the methylene blue test (MBT) of the mud are *known*:

a) Calculate the amount of bentonite in the mud in lb/bbl:

$$B_{ppb} = \left[\frac{1}{\left(1 - \left(\frac{F_{CEC}}{65}\right)\right)}\right]\left(M_{MBT} - 9\left(\frac{F_{CEC}}{65}\right)\right)LGS \tag{3.38}$$

Where: B_{ppb} = amount of bentonite in the mud in lb/bbl
F_{CEC} = CEC of the formation solids
M_{MBT} = MBT of the mud

b) Calculate the volume of bentonite in the mud in percent (%):

$$B_{\%} = \frac{B_{ppb}}{9.1} \tag{3.39}$$

Where: $B_{\%}$ = amount of bentonite in the mud in %

If the cation exchange capacities (CEC) of the formation clays are *not known*:

a) Calculate the volume of bentonite in percent (%):

$$B_{\%} = \frac{(M_{MBT} - LGS)}{8} \tag{3.40}$$

b) Calculate the amount of bentonite in the mud in lb/bbl:

$$B_{ppb} = 9.1(B_{\%}) \tag{3.41}$$

Step 11: Calculate the volume of drill solids in percent (%):

$$DS_{\%} = LGS - B_{\%} \tag{3.42}$$

Where: $DS_{\%}$ = volume of drill solids in %

Step 12: Calculate the amount of drill solids in the mud in lb/bbl:

$$DS_{ppb} = 9.1(DS_{\%}) \tag{3.43}$$

Example: Mud weight = 16.0 ppg
Chlorides = 73,000 ppm
MBT of mud = 30 lb/bbl
CEC of shale = 7 lb/bbl
Retort analysis:
water = 57.0% by volume
oil = 7.5% by volume (0.84 ASG diesel oil)
solids = 35.5% by volume (4.2 ASG barite)

Step 1: Calculate the volume of the salt water in %:

$$W_s = \left[\left(5.88 \times 10^{-8}(73{,}000^{1.2})\right) + 1\right](57)$$
$$W_s = (0.0403055 + 1)(57)$$
$$W_s = 59.297 \approx 59.3 \text{ volume of salt water in } \%$$

Step 2: Calculate the volume of suspended solids in %:

$$S_s = 100 - 7.5 - 59.3 = 33.2\ \% \text{ of suspended solids in the mud}$$

Step 3: Calculate the average specific gravity (ASG) of the salt water:

$$W_{ASG} = \left[(1.94 \times 10^{-6})(73{,}000l^{0.95})\right] + 1$$
$$W_{ASG} = [0.0809018] + 1$$
$$W_{ASG} = 1.0809$$

Step 4: Calculate the average specific gravity of the solids suspended in the mud:

$$S_{ASG} = \frac{(12(16.0)) - ((59.3)(1.0809)) - ((7.5)(0.84))}{33.2}$$

$$S_{ASG} = \frac{121.6}{33.2}$$

$$S_{ASG} = 3.66$$

Step 5: Because a high chloride example is being used, Step 5 is omitted.

Step 6: Calculate the volume of low gravity solids (LGS) in percent (%):

$$LGS = \frac{(33.2)(4.2 - 3.66)}{1.6}$$

$$LGS = \frac{(33.2)(4.2(3.66))}{1.6}$$

$$LGS = 11.2\% \text{ volume of LGS in the mud}$$

Step 7: Calculate the amount of LGS in lb/bbl:

$LGS_{ppb} = 9.1(11.2) = 101.9$ ppb **of LGS in the mud**

Step 8: Calculate the volume of the weight material in percent (%):

$$HGS = 33.2 - 11.2 = 22.0\% \text{ volume of barite weight material}$$

Step 9: Calculate the amount of high specific gravity weight material in pounds (lb/bbl):

$$HGS_{ppb} = 22.0(3.5(4.2))$$

$$HGS_{ppb} = 323.4 \text{ ppb of barite (HGS) in the mud}$$

Step 10: Calculate the amount of bentonite in the mud in lb/bbl:

$$B_{ppb} = \left[\frac{1}{\left(1 - \left(\frac{7.0}{65}\right)\right)}\right]\left(30.0 - 9\left(\frac{7.0}{65}\right)\right)11.2$$

$$B_{ppb} = (1.121)(2.262)(11.2)$$

$$B_{ppb} = 28.4 \text{ lb/bbl of bentonite in the mud}$$

Step 11: Calculate the volume of bentonite in the mud in percent (%):

$$B_{\%} = \frac{28.4}{9.1} = 3.12\% \text{ volume of bentonite in the mud}$$

Step 12: Calculate the volume of drill solids in percent (%):

$$DS_{\%} = 11.2 - 3.12 = 8.1\% \text{ volume of drill solids in the mud}$$

Step 13: Calculate the amount of drill solids in the mud in lb/bbl:

$$DS_{ppb} = 9.1(8.1) = 73.7 \text{ lb/bbl amount of drill solids in the mud}$$

3.5 Solids Fractions (Barite-Treated Muds)

3.5.1 Calculate the Maximum Recommended Solids Fraction in Percent (%) Based on the Mud Weight

$$S_{RM} = (2.917\ MW) - 14.17 \tag{3.44}$$

Where: S_{RM} = maximum recommended solids content in % by volume
MW = mud weight in ppg

3.5.2 Calculate the Maximum Recommended Low Gravity Solids (LGS) Fraction in Percent (%) Based on the Mud Weight

$$LGS_{RM} = \left(\frac{S_{RM}}{100} - \left[0.3125\left(\left(\frac{MW}{8.34}\right) - 1\right)\right]\right)200 \tag{3.45}$$

Where: LGS_{RM} = maximum recommended low gravity solids fractions, % by volume

Example: Calculate the maximum recommended solids content and LGS content in percent (%) with a 14.0 ppg water-based mud:

$$S_{RM} = (2.917(14.0)) - 14.17$$

$S_{RM} = 26.7\%$ maximum recommended solids content in the mud

$$LGS_{RM} = \left(\frac{26.7}{100} - \left[0.3125\left(\left(\frac{14.0}{8.34}\right) - 1\right)\right]\right)200$$

$$LGS_{RM} = 0.2667 - (0.3125(0.6787))(200)$$

$$LGS_{RM} = (0.2667 - 0.2121)(200)$$

$LGS_{RM} = (0.0566)(200) = 11.3\%$ maximum recommended LGS content in the mud

3.6 Dilution of Mud System

3.6.1 Calculate the Volume of Dilution in bbls Required to Reduce the Solids Content in the Mud System

$$V_{dm} = \frac{V_s(LGS - LGS_{RM})}{(LGS_{RM} - LGS_a)} \tag{3.46}$$

Where: V_{dm} = volume of dilution with base liquid or mud in bbls
LGS_a = low gravity solids from bentonite or chemicals added to the mud in %

Example: Calculate the volume of dilution required to change the LGS content from 6% to 4% in 1000 bbls of mud with fresh water:

$$V_{dm} = \frac{1000(6.0 - 4.0)}{(4.0 - 0.0)}$$

$V_{dm} = \dfrac{2000}{4.0} = 500$ bbls of water required

Example: Calculate the volume of dilution with a 2% bentonite slurry required to change the LGS content from 6% to 4% in 1000 bbls of mud:

$$V_{dm} = \frac{1000(6.0 - 4.0)}{(4.0 - 2.0)}$$

$$V_{dm} = \frac{2000}{2.0} = 1000 \text{ bbls of volume with the bentonite slurry}$$

3.6.2 Displacement—Barrels of Water/Slurry Required

$$V_{dmr} = \frac{V_s(LGS - LGS_{RM})}{(LGS - LGS_a)} \tag{3.47}$$

Where: V_{dmr} = volume of mud in bbls to be jetted and base liquid or slurry to be added to maintain constant circulating volume

Example: Calculate the volume of mud jetted or dumped to change the LGS content from 6% to 4% and maintain the mud system volume at 1000 bbls:

$$V_{dmr} = \frac{1000(6.0 - 4.0)}{(6.0 - 0.0)}$$

$$V_{dmr} = \frac{2000}{6.0} = 333.3 \text{ bbls to be displaced with the dilution volume}$$

Example: Calculate the volume of mud jetted or dumped to change the LGS content from 6% to 4% with a 2% bentonite slurry and maintain the mud system volume at 1000 bbls:

$$V_{dmr} = \frac{1000(6.0 - 4.0)}{(6.0 - 2.0)}$$

$$V_{dmr} = \frac{2000}{4.0} = 500 \text{ bbls to be displaced with the dilution volume}$$

3.7 Evaluation of Hydrocyclones

3.7.1 Calculate the Mass of Solids (for an Unweighted Mud) and the Volume of Water Discarded by One Cone of a Hydrocyclone (Desander or Desilter) with a Water-Based Mud

$$H_s = \frac{MW - 8.34}{13.37} \tag{3.48}$$

Where: H_s = volume fraction of solids discarded by the hydrocyclone (decimal)

3.7.2 Calculate the Mass Rate of Solids in gal/hr

$$S_{MR} = (19{,}530\ H_s)\left(\frac{V_Q}{t}\right) \tag{3.49}$$

Where: S_{MR} = mass rate of solids discharged by one cone of a hydrocyclone in lb/hr
V_Q = volume of slurry collected in quarts
t = time required to collect sample slurry in seconds

3.7.3 Calculate the Volume of Liquid Ejected by One Cone of a Hydrocyclone in gal/hr

$$V_H = 900(1 - H_s)\left(\frac{V_Q}{t}\right) \tag{3.50}$$

Where: V_H = volume of liquid ejected by one cone of a hydrocyclone in gal/hr

Example: Calculate the evaluation of a single hydrocyclone cone with the following data:

Average mud weight of slurry sample collected	16.0 ppg
Sample collection time	45 sec
Volume of slurry sample collected	2 qt

a) Calculate the volume fraction of solids discharged:

$$H_s = \frac{16.0 - 8.34}{13.37}$$

$$H_s = 0.573$$

b) Calculate the mass rate of solids discharged:

$$S_{MR} = (19{,}530(0.573))\left(\frac{2.0}{45}\right)$$

$$S_{MR} = 497.4 \text{ lb/hr of solids discarded}$$

c) Calculate the volume rate of liquid ejected by one cone:

$$V_H = 900(1 - 0.573)\left(\frac{2}{45}\right)$$

$$V_H = 900(0.427)(0.0444)$$

$$V_H = 17.1 \text{ gal/hr volume of liquid ejected by one cone}$$

3.8 Evaluation of Centrifuge

3.8.1 Evaluate the Centrifuge Underflow

a) Calculate the underflow mud volume in gal/min:

$$C_U = \frac{[C_F(MW - C_O)] - [C_D(C_O - MW_D)]}{(MW_U - C_O)} \tag{3.51}$$

Where: C_U = centrifuge underflow volume in gal/min
C_F = volume of mud feed into centrifuge in gal/min
C_O = centrifuge overflow mud weight in ppg
C_D = volume of dilution in gal/min
MW_D = mud weight of dilution liquid in ppg
MW_U = mud weight of underflow in ppg

b) Calculate the fraction of old mud in underflow in percent (%):

$$C_{OM} = \frac{(SG_{WM}(L_b)) - (MW_U)}{(SG_{WM}(L_b)) - MW + \left(\frac{C_D}{C_F}((SG_{WM}(L_b)) - MW_D)\right)} \quad (3.52)$$

Where: C_{OM} = volume fraction of mud in underflow in %

c) Calculate the mass rate of clay (LGS) going into the mixing pit in lb/min:

$$C_{UC} = \frac{LGS_{ppb}(C_F - (C_U(C_{OM})))}{42} \quad (3.53)$$

Where: C_{UC} = amount of clay in the centrifuge underflow in lb/min

d) Calculate the mass rate of additives in the underflow going into the mixing pit in lb/min:

$$C_{UA} = \frac{A(C_F - (C_U(C_{OM})))}{42} \quad (3.54)$$

Where: C_{UA} = mud additives in the underflow going into the mixing pit in lb/min
A = additive content in lb/bbl

e) Calculate the base liquid flow rate going into the mixing pit in gal/min:

$$C_{UL} = \frac{(C_F((3.5\ SG_{WM}) - MW)) - (C_U((3.5\ SG_{WM}) - MW_U)) - (0.6129\ C_{UC}) - (0.6129(C_{UA}))}{(3.5\ SG_{WM}) - L_b} \quad (3.55)$$

Where: C_{UL} = volume of base liquid flow rate going into the mixing pit in gal/min

f) Calculate the mass rate of weight material (barite) going into the mixing pit in lb/min:

$$C_{UB} = C_F - C_U - C_{UL} - \left(\frac{C_{UC}}{21.7}\right) - \left(\frac{C_{UA}}{21.7}\right)(3.5\ SG_{WM}) \quad (3.56)$$

Where: C_{UB} = amount of weight material going into the mixing pit in lb/min

Example: Calculate the following data:

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 barite into mixing pit

Mud density into centrifuge	= 16.2 ppg
Mud volume into centrifuge	= 16.5 ppg
Dilution water density	= 8.34 ppg
Dilution water volume	= 10.5 gal/min
Underflow mud density	= 23.4 ppg
Overflow mud density	= 9.3 ppg
Clay content of mud	= 22.5 lb/bbl
Additive content of mud	= 6 lb/bbl

a) Calculate the underflow mud volume in gal/min:

$$C_U = \frac{[16.5(16.2 - 9.3)] - [10.5(9.3 - 8.34)]}{(23.4 - 9.3)}$$

$$C_U = \frac{113.85 - 10.08}{14.1}$$

$$C_U = 7.4 \text{ gal/min}$$

b) Calculate the fraction of old mud in underflow in percent (%):

$$C_{OM} = \frac{(4.2(8.34)) - (23.4)}{(4.2(8.34)) - 16.2 + \left(\frac{10.5}{16.5}((4.2(8.34)) - 8.34)\right)}$$

$$C_{OM} = \frac{11.6}{18.8 + (0.63636(26.66))}$$

$$C_{OM} = 0.324\%$$

c) Calculate the mass rate of clay (LGS) going into the mixing pit in lb/min:

$$C_{UC} = \frac{22.5(16.5 - (7.4(0.324)))}{42}$$

$$C_{UC} = \frac{22.5(14.1)}{42}$$

$$C_{UC} = 7.55 \text{ lb/min}$$

d) Calculate the mass rate of additives in the underflow going into the mixing pit in lb/min:

$$C_{UA} = \frac{6.0(16.5 - (7.4(0.324)))}{42}$$

$$C_{UA} = \frac{6.0(14.1)}{42}$$

$$C_{UA} = 2.01 \text{ lb/min}$$

e) Calculate the base liquid flow rate going into the mixing pit in gal/min:

$$C_{UL} = \frac{\begin{array}{c}(16.5((3.5(4.2)) - 16.2)) - (7.4((3.5(4.2)) - 23.4))\\ - (0.6129(7.55)) - (0.6129(2.0))\end{array}}{(3.5(4.2)) - 8.34}$$

$$C_{UL} = \frac{218.5}{26.66} = 8.2 \text{ gal/min}$$

f) Calculate the mass rate of weight material (barite) going into the mixing pit in lb/min:

$$C_{UB} = 16.5 - 7.4 - 8.2 - \left(\frac{7.55}{21.7}\right) - \left(\frac{2.0}{21.7}\right)(35)$$

$$C_{UB} = 0.4599(35) = 16.1 \text{ lb/min}$$

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CHAPTER FOUR

Pressure Control: Kill Sheets and Related Calculations

4.0 Normal Kill Sheet

Prerecorded Data

Original mud weight (OMW) ____________________________ ppg
Measured depth (MD) ______________________________________ ft
Kill rate pressure (KRP) _____________ psi @ _______________ spm

Drill String Volume

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

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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

4.1 Calculations

Kill Weight Mud (KWM)

= SIDPP _____ psi ÷ 0.052 ÷ TVD _______ ft + OMW ______ ppg
= ______________ppg (4.1)

Initial Circulating Pressure (ICP)

= SIDPP _______ psi + KRP _________ psi = ________ psi (4.2)

Final Circulating Pressure (FCP)

$$= \text{KWM} \_\_\_\_\_\_\_\_ \text{ppg} \times \text{KRP} \_\_\_\_\_\_\_\_ \text{psi} - \text{OMW} \_\_\_\_\_\_\_\_ \text{ppg}$$
$$= \_\_\_\_\_\_\_\_\_\_\_\_ \text{psi} \quad (4.3)$$

Psi/Stroke

$$\text{ICP} \_\_\_\_\_\_\_\_ \text{psi} - \text{FCP} \_\_\_\_\_\_\_\_ \text{psi/strokes to bit} \_\_\_\_\_\_\_\_$$
$$= \_\_\_\_\_\_\_\_\_\_\_\_ \text{psi/stk} \quad (4.4)$$

	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
HWDP length = 240 ft
drill collars (8.0 in. OD—3.0 in. ID) capacity = 0.0087 bbl/ft
drill collars length = 360 ft

Annulus:	
hole size	= 12¼ 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

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
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

Trip Margin (TM)

$$\text{TM} = \text{Yield Point} \div 11.7(\text{Dh, in.} - \text{Dp, in.})$$

Example: Yield point = 10 lb/100 sq ft; Dh = 8.5 in.; Dp = 4.5 in.

$$\text{TM} = 10 \div 11.7(8.5 - 4.5)$$
$$\text{TM} = 0.2 \text{ ppg}$$

Determine psi/stk

$$\text{psi/stk} = \frac{\text{ICP} - \text{FCP}}{\text{strokes to bit}} \tag{4.5}$$

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

$$\text{psi/stk} = \frac{1480 - 1094}{1335}$$

$$\text{psi/stk} = 0.2891$$

The pressure side of the chart will appear as follows:

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 1 =		650
Line 4: Subtract 75 psi from Line 1 =		575
Line 5: Reduced casing pressure =		500

Adjust the strokes as necessary.

For line 2: How many strokes will be required to decrease the pressure from 1480 psi to 1450 psi?

$$1480 \text{ psi} - 1450 \text{ psi} = 30 \text{ psi}$$
$$30 \text{ psi} \div 0.2891 \text{ psi/stk} = 104 \text{ strokes}$$

For lines 3 to 7: How many strokes will be required to decrease the pressure by 50 psi increments?

$$50 \text{ psi} \div 0.2891 \text{ psi/stk} = 173 \text{ strokes}$$

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

4.2 Kill Sheet with a Tapered String

$$\text{Psi @ strokes} = \text{ICP} - \left[\left(\frac{\text{DPL}}{\text{DSL}}\right)(\text{ICP} - \text{FCP})\right] \tag{4.6}$$

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: 3½ in.—13.3 lb/ft
capacity = 0.0074 bbl/ft
length = 6000 ft

Drill collars: 4½ in. OD × 1½ in. ID	
capacity	= 0.0022 bbl/ft
length	= 2000 ft
Pump output	= 0.117 bbl/stk

Step 1

Determine strokes:

(7000 ft)(0.01776 bbl/ft) ÷ 0.117 bbl/stk	= 1063
(6000 ft)(0.00742 bbl/ft) ÷ 0.117 bbl/stk	= 381
(2000 ft)(0.0022 bbl/ft) ÷ 0.117 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:

$$\begin{aligned}\text{psi @ 1063 strokes} &= 1780 - \left[\left(\frac{7000}{15{,}000}\right)(1780 - 1067)\right]\\ &= 1780 - (0.86666 \times 713)\\ &= 1780 - 333\\ &= 1447\ \text{psi}\end{aligned}$$

Step 3

Determine interim pressure for 5.0 in. plus 3½ in. drill pipe (1063 + 381) = 1444 strokes:

$$\begin{aligned}\text{Psi @ 1444 strokes} &= 1780 - \left[\left(\frac{13{,}000}{15{,}000}\right)(1780 - 1067)\right]\\ &= 1780 - (0.86666 \times 713)\\ &= 1780 - 618\\ &= 1162\ \text{psi}\end{aligned}$$

Step 4

Plot data on graph paper:

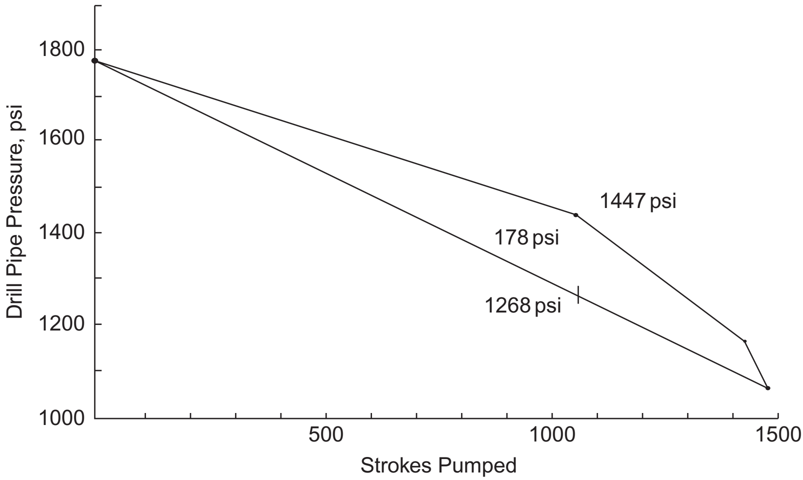

Figure 4-1. Data from kill sheet.

NOTE: After pumping 1062 strokes, if a straight line would have been plotted, the well would have been underbalanced by 178 psi.

4.3 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 the surface to KOP; 2) and from KOP to TD. The following calculations are used:

Determine strokes from surface to KOP:

$$\text{Strokes} = \text{drill pipe capacity, bbl/ft} \times \text{measured depth to KOP, ft} \div \text{pump output, bbl/stk} \tag{4.7}$$

Determine strokes from KOP to TD:

$$\text{Strokes} = \text{drill string capacity, bbl/ft} \times \text{measured depth to TD, ft} \div \text{pump output, bbl/stk} \tag{4.8}$$

Kill weight mud using equation (4.1):

$$KWM = SIDPP \div 0.052 \div TVD + OMW$$

Initial circulating pressure using equation (4.2):

$$ICP = SIDPP + KRP$$

Final circulating pressure using equation (4.3):

$$FCP = KWM \times KRP \div OMW$$

Hydrostatic pressure increase from surface to KOP:

$$psi = (KWM - OMW) \times 0.052 \times TVD\ @\ KOP \tag{4.9}$$

Friction pressure increase to KOP:

$$FP = (FCP - KRP) \times MD\ @\ KOP - MD\ @\ TD \tag{4.10}$$

Circulating pressure when KWM gets to KOP:

$$\begin{aligned} CP\ @\ KOP = {} & ICP - HP \text{ increase to } KOP \\ & + \text{friction pressure increase}, 1 \end{aligned} \tag{4.11}$$

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:

$$\text{Strokes} = 0.01776\ \text{bbl/ft} \times 5000\ \text{ft} \div 0.136\ \text{bbl/stk}$$
$$\text{Strokes} = 653$$

Strokes from KOP to TD:

$$\text{Strokes} = 0.01776\ \text{bbl/ft} \times 10{,}000\ \text{ft} \div 0.136\ \text{bbl/stk}$$
$$\text{Strokes} = 1306$$

Total strokes from surface to bit:

$$\text{Surface to bit strokes} = 653 + 1306$$
$$\text{Surface to bit strokes} = 1959$$

Kill weight mud (KWM):

$$\text{KWM} = 800\ \text{psi} \div 0.052 \div 10{,}000\ \text{ft} + 9.6\ \text{ppg}$$
$$\text{KWM} = 11.1\ \text{ppg}$$

Initial circulating pressure (ICP):

$$\text{ICP} = 800\ \text{psi} + 600\ \text{psi}$$
$$\text{ICP} = 1400\ \text{psi}$$

Final circulating pressure (FCP):

$$\text{FCP} = 11.1\ \text{ppg} \times 600\ \text{psi} \div 9.6\ \text{ppg}$$
$$\text{FCP} = 694\ \text{psi}$$

Hydrostatic pressure increase from surface to KOP:

$$\text{HPi} = (11.1 - 9.6) \times 0.052 \times 5000$$
$$\text{HPi} = 390\ \text{psi}$$

Friction pressure increase to TD:

$$FP = (694 - 600) \times 5000 \div 15{,}000$$
$$FP = 31 \text{ psi}$$

Circulating pressure when KWM gets to KOP:

$$CP = 1400 - 390 + 31$$
$$CP = 1041 \text{ psi}$$

Compare this circulating pressure to the value obtained when using a regular kill sheet:

$$\begin{aligned} \text{psi/stk} &= 1400 - 694 \div 1959 \\ \text{psi/stk} &= 0.36 \\ 0.36 \text{ psi/stk} \times 653 \text{ stk} &= 235 \text{ psi} \\ 1400 - 235 &= 1165 \text{ psi} \end{aligned}$$

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 a 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:

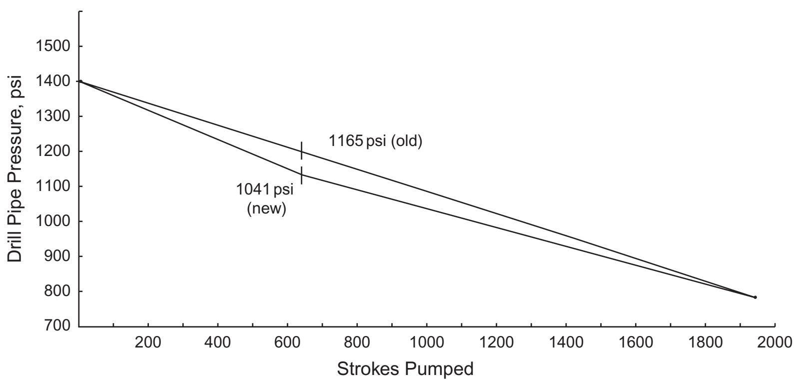

Figure 4-2. Adjusted pressure chart.

4.4 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 (FP_{max}):

$$FP_{max} = \left(\frac{\text{maximum mud weight to be used, ppg}}{\text{safety factor, ppg}}\right)(0.052)\left(\begin{matrix}\text{total}\\ \text{depth, ft}\end{matrix}\right) \tag{4.12}$$

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%.

$$HP_{gas} = \text{gas gradient, psi/ft} \times \text{total depth, ft} \tag{4.13}$$

Step 3

Determine maximum anticipated surface pressure (MASP):

$$MASP = FP_{max} - Hp_{gas} \tag{4.14}$$

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 the mud is blown out of the well.

Step l

$$FP_{max} = (12.0 + 4.0) \times 0.052 \times 12{,}000 \text{ ft}$$
$$FP_{max} = 9984 \text{ psi}$$

Step 2

$$HP_{gas} = 0.12 \times 12{,}000 \text{ ft}$$
$$HP_{gas} = 1440 \text{ psi}$$

Step 3

$$MASP = 9984 - 1440$$
$$MASP = 8544 \text{ psi}$$

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:

$$\begin{matrix}\text{Fracture}\\ \text{pressure, psi}\end{matrix} = \left(\begin{matrix}\text{estimated}\\ \text{fracture}\\ \text{gradient, ppg}\end{matrix} + \begin{matrix}\text{safety}\\ \text{factor,}\\ \text{ppg}\end{matrix}\right)(0.052)\left(\begin{matrix}\text{casing shoe}\\ \text{TVD, ft}\end{matrix}\right) \tag{4.15}$$

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 (HP_{gas}):

$$HP_{gas} = \text{gas gradient, psi/ft} \times \text{casing shoe TVD, ft} \tag{4.16}$$

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

$$\text{Fracture pressure, psi} = (14.0 + 1.0) \times 0.052 \times 4000 \text{ ft}$$

Step 2

$$HP_{gas} = 0.12 \times 4000 \text{ ft}$$
$$HP_{gas} = 480 \text{ psi}$$

Step 3

$$MASP = 3162 - 480$$
$$MASP = 2682 \text{ psi}$$

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 the drill pipe in use:

$$\text{Diverter line ID, in.} = \sqrt{Dh^2 - Dp^2} \quad (4.17)$$

Example:

Casing—13⅜ 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 the drill pipe:

$$\text{Diverter line ID, in.} = \sqrt{12.515^2 - 5.0^2}$$
$$\text{Diverter line ID} = 11.47 \text{ in.}$$

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: ¼ to ½ 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 necessary to drill the next interval = 11.5 ppg plus safety factor = 1.0 ppg

Equivalent test mud weight, ppg = (maximum mud weight, ppg) + (safety factor, ppg)

Equivalent test mud weight, ppg = 11.5 ppg + 1.0 ppg

Equivalent test mud weight, ppg = 12.5 ppg

Method 2: Subtract a value from the estimated fracture gradient for the depth of the casing shoe.

Equivalent test mud weight, ppg = (estimated fracture gradient, ppg) – (safety factor, ppg)

Example: Estimated formation fracture gradient = 14.2 ppg
Safety factor = 1.0 ppg

Equivalent test mud weight, ppg = 14.2 ppg – 1.0 ppg

Equivalent test mud weight, ppg = 13.5 ppg

Determine surface pressure to be used:

$$\begin{matrix}\text{Surface}\\ \text{pressure, psi}\end{matrix} = \left(\begin{matrix}\text{equivalent}\\ \text{test mud}\\ \text{weight, ppg}\end{matrix} - \begin{matrix}\text{mud weight}\\ \text{in use, ppg}\end{matrix}\right)(0.052)\left(\begin{matrix}\text{casing shoe}\\ \text{TVD, ft}\end{matrix}\right) \tag{4.18}$$

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 test:

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.

$$\begin{matrix}\text{Estimated}\\ \text{leak-off}\\ \text{pressure, psi}\end{matrix} = \left(\begin{matrix}\text{estimated}\\ \text{fracture}\\ \text{gradient, ppg}\end{matrix} - \begin{matrix}\text{mud weight}\\ \text{in use, ppg}\end{matrix}\right)(0.052)\left(\begin{matrix}\text{casing}\\ \text{seat}\\ \text{TVD, ft}\end{matrix}\right) \tag{4.19}$$

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
Estimated leak-off pressure = 998 psi

Maximum Allowable Mud Weight from Leak-Off Test Data

$$\begin{array}{c}\text{Max allowable}\\ \text{mud weight,}\\ \text{ppg}\end{array} = \begin{pmatrix}\text{leak-off}\\ \text{pressure,}\\ \text{psi}\end{pmatrix} \div 0.052 \div \begin{pmatrix}\text{casing}\\ \text{shoe}\\ \text{TVD, ft}\end{pmatrix} + \begin{pmatrix}\text{mud}\\ \text{weight in}\\ \text{use, ppg}\end{pmatrix} \qquad (4.20)$$

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
Max allowable mud weight, ppg = 1040/0.052 ÷ 4000 + 10.0
Max allowable mud weight, ppg = 15.0 ppg

Maximum Allowable Shut-In Casing Pressure (MASICP), Also Called Maximum Allowable Shut-In Annular Pressure (MASP)

$$\text{MASICP} = \begin{pmatrix}\text{maximum}\\ \text{allowable mud}\\ \text{weight, ppg}\end{pmatrix} - \begin{array}{c}\text{mud weight}\\ \text{in use, ppg}\end{array} \Bigg) (0.052) \begin{pmatrix}\text{casing}\\ \text{shoe}\\ \text{TVD, ft}\end{pmatrix} \qquad (4.21)$$

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)

$$\text{KTF} = \left(\begin{array}{ccc}\text{casing} & & \text{well}\\ \text{shoe} & \div & \text{depth}\\ \text{TVD, ft} & & \text{TVD, ft}\end{array}\right)\left(\begin{array}{ccc}\text{maximum} & & \\ \text{allowable mud} & - & \begin{array}{c}\text{mud weight}\\ \text{in use, ppg}\end{array}\\ \text{weight, ppg} & & \end{array}\right) \qquad (4.22)$$

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

$$\text{KTF} = (4000\text{ ft}/10{,}000\text{ ft}) \times (14.2\text{ ppg} - 10.0\text{ ppg})$$
$$\text{KTF} = 1.68\text{ ppg}$$

Maximum Surface Pressure from Kick Tolerance Data

$$\text{Maximum surface pressure, psi} = \text{kick tolerance factor, ppg} \times 0.052 \times \text{TVD, ft} \qquad (4.23)$$

Example: Determine the maximum surface pressure, psi, using the following data:

$$\text{Maximum surface pressure, psi} = 1.68\text{ ppg} \times 0.052 \times 10{,}000\text{ ft}$$

$$\text{Maximum surface pressure, psi} = 874\text{ psi}$$

Maximum Formation Pressure (FP) That Can Be Controlled when Shutting in a Well

$$\text{Maximum FP, psi} = \left(\begin{matrix}\text{kick tolerance}\\ \text{factor, ppg}\end{matrix} + \begin{matrix}\text{mud weight}\\ \text{in use, ppg}\end{matrix}\right)(0.052)\,\text{TVD, ft} \qquad (4.24)$$

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)

$$\text{Influx height, ft} = \text{MASICP, psi} \Big/ \left(\begin{array}{c}\text{gradient of mud}\\ \text{weight in use, psi/ft}\end{array} - \begin{array}{c}\text{influx}\\ \text{gradient, psi/ft}\end{array}\right) \tag{4.25}$$

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 (12¼ in. × 8.0 in.) = 0.0836 bbl/ft
Drill collar length = 500 ft
Annular capacity – drill pipe/open hole (12¼ in. × 5.0 in.) = 0.1215 bbl/ft

Step 1

Determine the number of barrels opposite the drill collars:

Barrels = 0.0836 bbl/ft × 500 ft
Barrels = 41.8

Step 2

Determine the number of barrels opposite the drill pipe:

Influx height, ft, opposite the drill pipe:

$$\text{ft} = 2185\ \text{ft} - 500\ \text{ft}$$
$$\text{ft} = 1685$$

Barrels opposite the drill pipe:

$$\text{Barrels} = 1685\ \text{ft} \times 0.1215\ \text{bbl/ft}$$
$$\text{Barrels} = 204.7$$

Step 3

Determine maximum influx, bbl, to equal maximum allowable shut-in casing pressure:

$$\text{Maximum influx} = 41.8\ \text{bbl} + 204.7\ \text{bbl}$$
$$\text{Maximum influx} = 246.5\ \text{bbl}$$

Adjusting Maximum Allowable Shut-In Casing Pressure for an Increase in Mud Weight

$$\text{MASICP} = P_L - [D \times (\text{mud weight}_2 - \text{mud weight}_1)]\ 0.052 \tag{4.26}$$

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 weight_2 = new mud weight, ppg
Mud weight_1 = original mud weight, 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:

$$\text{MASICP} = 1040\ \text{psi} - [4000 \times (12.5 - 10.0) \times 0.052]$$
$$\text{MASICP} = 1040\ \text{psi} - 520$$
$$\text{MASICP} = 520\ \text{psi}$$

4.5 Kick Analysis

Formation Pressure (FP) with the Well Shut-In on a Kick

$$\text{FP, psi} = \text{SIDPP, psi} + (\text{mud weight, ppg} \times 0.052 \times \text{TVD, ft}) \tag{4.27}$$

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

$$\text{BMP, psi} = \text{SIDPP, psi} + (\text{mud weight, ppg} \times 0.052 \times \text{TVD, ft}) \tag{4.28}$$

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

BHP, psi = 500 psi + (9.6 ppg × 0.052 × 10,000 ft)
BHP, psi = 500 psi + 4992 psi
BHP = 5492 psi

Shut-In Drill Pipe Pressure (SIDPP)

$$\text{SIDPP, psi} = \begin{matrix}\text{formation}\\ \text{pressure, psi}\end{matrix} - \begin{pmatrix}\text{mud weight, ppg}\\ \times 0.052 \times \text{TVD, ft}\end{pmatrix} \tag{4.29}$$

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

SIDPP, psi = 12,480 psi – (15.0 ppg × 0.052 × 15,000 ft)
SIDPP, psi = 12,480 psi – 11,700 psi
SIDPP = 780 psi

Shut-In Casing Pressure (SICP)

$$\text{SICP} = \begin{pmatrix}\text{formation}\\ \text{pressure, psi}\end{pmatrix} - \begin{pmatrix}\text{HP of mud in}\\ \text{annulus, psi} + \text{HP of influx in}\\ \text{annulus, psi}\end{pmatrix} \tag{4.30}$$

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

$$\text{Height of influx, ft} = \text{pit gain, bbl/annular capacity, bbl/ft} \tag{4.31}$$

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 = 8½ in.; Dp = 6½ in.)

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 = 8½ in.
Drill collar OD = 6½ in.
Drill collar length = 450 ft
Drill pipe OD = 5.0 in.

Determine annular capacity, bbl/ft, for DC/OH:

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

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

Determine the number of barrels opposite the drill collars:

Barrels = length of collars $\times$ annular capacity
Barrels = 450 ft $\times$ 0.02914 bbl/ft
Barrels = 13.1

Determine annular capacity, bbl/ft, opposite drill pipe:

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

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

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:

$$\text{Height, ft} = 450\text{ ft} + 150\text{ ft}$$
$$\text{Height} = 600\text{ ft}$$

Estimated Type of Influx

$$\text{Influx weight, ppg} = \text{mud weight, ppg} - \left(\frac{\text{SCIP} - \text{SIDPP}}{\text{height of influx, ft}(0.052)}\right) \tag{4.32}$$

then: 1–3 ppg = gas kick
4–6 ppg = oil kick or combination
7–9 ppg = salt water 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

$$\text{Influx weight, ppg} = 15.0 - \left(\frac{1044 - 780}{400(0.052)}\right)$$
$$\text{Influx weight, ppg} = 15.0 - \left(\frac{264}{20.8}\right)$$
$$\text{Influx weight, ppg} = 2.31\text{ ppg}$$

Therefore, the influx is probably "gas."

Gas Migration in a Shut-In Well

Estimating the rate of gas migration, ft/hr:

$$\text{Vg} = 12e^{(-0.37)(\text{mud weight, ppg})} \tag{4.33}$$
$$\text{Vg} = \text{rate of gas migration, ft/hr}$$

Example: Determine the estimated rate of gas migration using a mud weight of 11.0 ppg:

$$\begin{aligned}
Vg &= 12e^{(-0.37)(11.0\ \text{ppg})}\\
Vg &= 12e^{(-4.07)}\\
Vg &= 0.205\ \text{ft/sec}\\
Vg &= 0.205\ \text{ft/sec} \times 60\ \text{sec/min}\\
Vg &= 12.3\ \text{ft/min} \times 60\ \text{min/hr}\\
Vg &= 738\ \text{ft/hr}
\end{aligned}$$

Determining the *actual* rate of gas migration after a well has been shut in on a kick:

$$\begin{matrix}\text{Rate of gas}\\ \text{migration, ft/hr}\end{matrix} = \begin{pmatrix}\text{increase in casing}\\ \text{pressure, psi/hr}\end{pmatrix} \div \begin{pmatrix}\text{pressure gradient}\\ \text{of mud weight in}\\ \text{use, psi/ft}\end{pmatrix} \tag{4.34}$$

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

$$\text{Migration rate, m/hr} = \frac{\text{increase in casing pressure, bar/hr}}{\text{drilling fluid density, kg/l (0.0981)}} \tag{4.35}$$

SI Units Calculation

$$\text{Migration rate, m/hr} = \frac{\text{increase in casing pressure, kPa/hr(102)}}{\text{drilling fluid density, kg/m}^3} \tag{4.36}$$

Hydrostatic Pressure Decrease at TD Caused by Gas-Cut Mud

Method 1

$$\text{HP decrease, psi} = \frac{100\begin{pmatrix}\text{weight of uncut mud, ppg} - \\ \text{weight of gas-cut mud, ppg}\end{pmatrix}}{\text{weight of gas-cut mud, ppg}} \tag{4.37}$$

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

$$\text{HP decrease, psi} = \frac{100\,(18.0\text{ ppg} - 9.0\text{ ppg})}{9.0\text{ ppg}}$$

$$\text{HP decrease} = 100\text{ psi}$$

Method 2

$$P = (MG/C)V$$

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 = 8½ in.; Dp = 5.0 in.)
V = 20 bbl

Solution: $P = (0.624\text{ psi/ft} \div 0.0459\text{ bbl/ft})\ 20$
$P = 13.59 \times 20$
$P = 271.9\text{ psi}$

Maximum Surface Pressure from a Gas Kick in a Water-Base Mud

$$\text{MSPgk} = 0.2\sqrt{\frac{P \times V \times KWM}{C}} \tag{4.38}$$

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 = 8½ in. × Dp = 4½ in.)

Solution:

$$\text{MSPgk} = 0.2\sqrt{\frac{12{,}480 \times 20 \times 16.0}{0.0505}}$$

$$= 0.2\sqrt{79{,}081{,}188}$$

$$= 0.2 \times 8892.76$$

$$\text{MSPgk} = 1779 \text{ psi}$$

Maximum Pit Gain from Gas Kick in a Water-Base Mud

$$\text{MPGgk} = 4\sqrt{\frac{P \times V \times C}{\text{KWM}}} \tag{4.39}$$

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 (8½ in. × 4½ in.)
KWM = 16.0 ppg

Solution:

$$\text{MPGgk} = 4\sqrt{\frac{12{,}480 \times 20 \times 0.0505}{16.0}}$$
$$= 4\sqrt{787.8}$$
$$= 4 \times 28.068$$
$$\text{MPGgk} = 112.3 \text{ bbl}$$

Maximum Pressures when Circulating Out a Kick (Moore Equations)

The following equations will be used:

1. Determine formation pressure, psi:

$$\text{Pb} = \text{SIDP} + (\text{mud weight, ppg} \times 0.052 \times \text{TVD, ft}) \tag{4.40}$$

2. Determine the height of the influx, ft:

$$\text{hi} = \text{pit gain, bbl} \div \text{annular capacity, bbl/ft} \tag{4.41}$$

3. Determine pressure exerted by the influx, psi:

$$\text{Pi} = \text{Pb} - [\text{Pm}(\text{D} - \text{X}) + \text{SICP}] \tag{4.42}$$

4. Determine gradient of influx, psi/ft:

$$\text{Ci} = \text{Pi} \div \text{hi} \tag{4.43}$$

5. Determine temperature, °R, at depth of interest:

$$\text{Tdi} = 70^\circ\text{F} + (0.012^\circ\text{F/ft} \times \text{Di}) + 46 \tag{4.44}$$

6. Determine A for unweighted mud:

$$\text{A} = \text{Pb} - [\text{Pm}(\text{D} - \text{X}) - \text{Pi}] \tag{4.45}$$

7. Determine pressure at depth of interest:

$$\text{Pdi} = \frac{\text{A}}{2} + \left(\frac{\text{A}^2}{4} + \frac{\text{pm Pb Zdi T}^\circ\text{Rdi hi}}{\text{Zb Tb}}\right)^{1/2} \tag{4.46}$$

8. Determine kill weight mud, ppg from equation (4.1):

$$\text{KWM, ppg} = \text{SIDPP}/0.052/\text{TVD, ft} + \text{OMW, ppg}$$

9. Determine gradient of kill weight mud, psi/ft:

$$\text{pKWM} = \text{KWM, ppg} \times 0.052 \tag{4.47}$$

10. Determine feet that drill string volume will occupy in the annulus:

$$\text{Di} = \text{drill string vol, bbl} \div \text{annular capacity, bbl/ft} \tag{4.48}$$

11. Determine A for weighted mud:

$$\text{A} = \text{Pb} - [\text{pm(D} - \text{X)} - \text{Pi}] + [\text{Di(pKWM} - \text{pm)}] \tag{4.49}$$

Example: Assumed conditions:

Well depth	= 10,000 ft
Surface casing	= 9⅝ in. @ 2500 ft
Casing ID	= 8.921 in.
capacity	= 0.077 bbl/ft
Hole size	= 8½ in.
Drill pipe	= 4½ in.—16.6 lb/ft
Drill collar OD	= 6¼ in.
length	= 625 ft
Mud weight	= 9.6 ppg
Fracture gradient @ 2500 ft	= 0.73 psi/ft (14.04 ppg)

Mud volumes:

8½ in. hole	= 0.07 bbl/ft
8½ in. hole × 4½ in. drill pipe	= 0.05 bbl/ft
8½ in. hole × 6¼ in. drill collars	= 0.032 bbl/ft
8.921 in. casing × 4½ 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:

   $Ci = 72\ psi + 625\ ft$
   $Ci = 0.1152\ psi/ft$

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:

$$\begin{aligned}
A &= 5252\ psi - [0.4992\ (10{,}000 - 2500) + 46] \\
A &= 5252\ psi - (3744 - 46) \\
A &= 1462\ psi
\end{aligned}$$

8. Determine maximum pressure at shoe with drillers method:

$$\begin{aligned}
P_{2500} &= \frac{1462}{2} + \left[\frac{1462^2}{4} + \frac{(0.4992)(5252)(1)(560)(400)}{(1)(650)}\right]^{1/2} \\
&= 731 + (534{,}361 + 903{,}512)^{1/2} \\
&= 731 + 1199 \\
P_{2500} &= 1930\ psi
\end{aligned}$$

Determine maximum pressure at surface with drillers method:

1. Determine A:

$$\begin{aligned}
A &= 5252 - [0.4992(10{,}000) + 46] \\
A &= 5252 - (4992 + 46) \\
A &= 214\ psi
\end{aligned}$$

2. Determine maximum pressure at surface with drillers method:

$$\begin{aligned}
Ps &= \frac{214}{2} + \left[\frac{214^2}{4} + \frac{(0.4992)(5252)(530)(400)}{(650)}\right]^{1/2} \\
&= 107 + (11{,}449 + 855{,}109)^{1/2} \\
&= 107 + 931 \\
Ps &= 1038\ psi
\end{aligned}$$

Determine maximum pressure at shoe with wait and weight method:

1. Determine kill weight mud:

   $$\text{KWM, ppg} = 260 \text{ psi}/0.052/10{,}000 \text{ ft} + 9.6 \text{ ppg}$$
   $$\text{KWM, ppg} = 10.1 \text{ ppg}$$

2. Determine gradient (pm), psi/ft, for KWM:

   $$\text{pm} = 10.1 \text{ ppg} \times 0.052$$
   $$\text{pm} = 0.5252 \text{ psi/ft}$$

3. Determine internal volume of drill string:

   $$\begin{aligned} &\text{Drill pipe volume} = 0.014 \text{ bbl/ft} \times 9375 \text{ ft} &&= 131.25 \text{ bbl} \\ &\text{Drill collar volume} = 0.007 \text{ bbl/ft} \times 625 \text{ ft} &&= 4.375 \text{ bbl} \\ &\text{Total drill string volume} &&= 135.625 \text{ bbl} \end{aligned}$$

4. Determine feet drill string volume occupies in annulus:

   $$\text{Di} = 135.625 \text{ bbl} \div 0.05 \text{ bbl/ft}$$
   $$\text{Di} = 2712.5$$

5. Determine A:

   $$\begin{aligned} A &= 5252 - [0.5252\,(10{,}000 - 2500) - 46] + \\ &\quad [2715.2\,(0.5252 - 0.4992)] \\ A &= 5252 - (3939 - 46) + 70.6 \\ A &= 1337.5 \end{aligned}$$

6. Determine maximum pressure at shoe with wait and weight method:

   $$\begin{aligned} P_{2500} &= \frac{1337.5}{2} + \left[\frac{1337.5^2}{4} + \frac{(0.5252)(5252)(1)(560)(400)}{(1)(650)}\right]^{1/2} \\ &= 668.75 + (447{,}226 + 950{,}569.98)^{1/2} \\ &= 668.75 + 1182.28 \\ &= 1851 \text{ psi} \end{aligned}$$

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
Pi	= pressure exerted by influx, psi
pKWM	= pressure gradient of kill weight mud, ppg
pm	= pressure gradient of mud weight in use, ppg
Ps	= pressure at surface, psi
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:

$$Q = 0.007 \times md \times Dp \times L \div \mu \times \ln(Re \div Rw)\ 1440 \tag{4.50}$$

Where: Q = flow rate, bbl/min
md = permeability, millidarcys
Dp = pressure differential, psi
L = length of section open to wellbore, ft
μ = 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
μ = 0.3 cp
ln(Re ÷ Rw) = 2.0

$$Q = 0.007 \times 200 \times 624 \times 20/0.3 \times 2.0 \times 1440$$
$$Q = 20\ \text{bbl/min}$$

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.

4.6 Pressure Analysis

Gas Expansion Equations

Basic gas laws:

$$P_1V_1 \div T_1 = P_2V_2 \div T_2 \tag{4.51}$$

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:

$$P_1V_1 \div T_1Z_1 = P_2V_2 \div T_2Z_2 \tag{4.52}$$

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:

$$P_1V_1 = P_2V_2 \tag{4.53}$$

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:

$$\text{psi/bbl} = \frac{1029.4}{\text{Dh}^2 - \text{Dp}^2}(0.052)\text{ mud weight, ppg}$$

Example: Dh—9⅝ in. casing—43.5 lb/ft = 8.755 in. ID
Dp = 5.0 in. OD
Mud weight = 10.5 ppg

$$\text{psi/bbl} = \frac{1029.4}{8.755^2 - 5.0^2}(0.052)(10.5\text{ ppg})$$

$$\text{psi/bbl} = 19.93029 \times 0.052 \times 10.5\text{ ppg}$$
$$\text{psi/bbl} = 10.88$$

With no pipe in the wellbore:

$$\text{psi/bbl} = \frac{1029.4}{\text{ID}}(0.052)\text{ mud weight, ppg}$$

Example: Dh—9⅝ in. casing—43.5 lb/ft = 8.755 in. ID
Mud weight = 10.5 ppg

$$\text{psi/bbl} = \frac{1029.4}{8.755^2}(0.052)(10.5\text{ ppg})$$

$$\text{psi/bbl} = 13.429872 \times 0.052 \times 10.5\text{ ppg}$$
$$\text{psi/bbl} = 7.33$$

Surface Pressure during Drill Stem Tests

Determine formation pressure from equation (4.12):

$$\text{psi} = \text{formation pressure equivalent mud weight, ppg} \times 0.052 \times \text{TVD, ft}$$

Determine oil hydrostatic pressure:

$$\text{psi} = \text{oil specific gravity} \times 0.052 \times \text{TVD, ft} \tag{4.54}$$

Determine surface pressure:

$$\text{Surface pressure, psi} = \text{formation pressure, psi} - \text{oil hydrostatic pressure, psi} \tag{4.55}$$

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:

$$\text{Surface pressure, psi} = 8775 \text{ psi} - 2707 \text{ psi}$$
$$\text{Surface pressure} = 6068 \text{ psi}$$

4.7 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 (6¼ in.—2¹³⁄₁₆ 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 6¼ in. drill collars:

$$\text{Force, lb} = (\text{pipe or collar OD, in.} \times 0.7854 \times \text{wellbore pressure, psi})$$
$$\text{Force, lb} = 6.25^2 \times 0.7854 \times 2400 \text{ psi}$$
$$\text{Force} = 73{,}631 \text{ lb}$$

Determine the weight, lb, of the drill collars:

$$\text{Wt, lb} = \text{drill collar weight, lb/ft} \times \text{drill collar length, ft} \times \text{buoyancy factor}$$
$$\text{Wt, lb} = 83 \text{ lb/ft} \times 276 \text{ ft} \times 0.8092$$
$$\text{Wt, lb} = 18{,}537 \text{ lb}$$

Additional weight required from drill pipe:

$$\begin{aligned}\text{Drill pipe weight, lb} &= \text{force created by wellbore pressure,}\\ &\quad\ \text{lb} - \text{drill collar weight, lb}\\ \text{Drill pipe weight, lb} &= 73{,}631\text{ lb} - 18{,}537\text{ lb}\\ \text{Drill pipe weight} &= 55{,}094\text{ lb}\end{aligned}$$

Length of drill pipe required to reach breakover point:

$$\text{Drill pipe length, ft} = \begin{pmatrix}\text{required drill}\\ \text{pipe weight, lb}\end{pmatrix} \div \begin{pmatrix}\text{drill pipe weight, lb/ft}\\ \text{(buoyancy factor)}\end{pmatrix}$$

$$\begin{aligned}\text{Drill pipe length, ft} &= 55{,}094\text{ lb} \div (19.5\text{ lb/ft} \times 08092)\\ \text{Drill pipe length} &= 3492\text{ ft}\end{aligned}$$

(4.56)

Length of drill string required to reach breakover point:

$$\begin{aligned}\text{Drill string length, ft} &= \text{drill collar length, ft} + \text{drill pipe length, ft}\\ \text{Drill string length, ft} &= 276\text{ ft} + 3492\text{ ft}\\ \text{Drill string length} &= 3768\text{ ft}\end{aligned}$$

Minimum Surface Pressure before Stripping Is Possible

$$\begin{matrix}\text{Minimum surface}\\ \text{pressure, psi}\end{matrix} = \begin{pmatrix}\text{weight of one}\\ \text{stand of collars, lb}\end{pmatrix} \div \begin{pmatrix}\text{area of}\\ \text{collars, sq. in.}\end{pmatrix} \tag{4.57}$$

Example: Drill collars—8.0 in. OD × 3.0 in. ID = 147 lb/ft
Length of one stand = 92 ft

$$\begin{aligned}\text{Minimum surface pressure, psi} &= (147\text{ lb/ft} \times 92\text{ ft}) \div (8^2 \times 0.7854)\\ \text{Minimum surface pressure, psi} &= 13{,}325 \div 50.2656\text{ sq. in.}\\ \text{Minimum surface pressure} &= 269\text{ psi}\end{aligned}$$

Height Gain from Stripping into Influx

$$\text{Height, ft} = \frac{\text{L(Cdp + Ddp)}}{\text{Ca}} \tag{4.58}$$

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 12¼ 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: $\text{Height, ft} = \dfrac{300(0.1776 + 0.00755)}{0.1215}$

Height = 62.5 ft

Casing Pressure Increase from Stripping into Influx

$$\text{psi} = \begin{pmatrix}\text{gain in}\\ \text{height, ft}\end{pmatrix} \times \begin{pmatrix}\text{gradient of} & - & \text{gradient of}\\ \text{mud, psi/ft} & & \text{influx, psi/ft}\end{pmatrix} \tag{4.59}$$

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

psi = 62.5 ft × (0.65 – 0.12)
psi = 33 psi

Volume of Mud That Must Be Bled to Maintain Constant Bottomhole Pressure with a Gas Bubble Rising

With pipe in the hole:

$$V_{mud} = \frac{\text{Dp} \times \text{Ca}}{\text{gradient of mud, psi/ft}} \tag{4.60}$$

Where: V_{mud} = 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 = 12¼ in.; Dp = 5.0 in.)

$$V_{mud} = \frac{100\ \text{psi}(0.1215\ \text{bbl/ft})}{0.702\ \text{psi/ft}}$$

$$V_{mud} = 17.3\ \text{bbl}$$

With no pipe in hole:

$$V_{mud} = \frac{\text{Dp (Ch)}}{\text{gradient of mud, psi/ft}} \tag{4.61}$$

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 (12¼ in.) = 0.1458 bbl/ft

$$V_{mud} = \frac{100\ \text{psi (0.1458 bbl/ft)}}{0.702\ \text{psi}}$$

$$V_{mud} = 20.77\ \text{bbl}$$

Maximum Allowable Surface Pressure (MASP) Governed by the Formation from Equation (4.22)

$$\text{MASP, psi} = \left(\begin{array}{c}\text{maximum}\\ \text{allowable mud}\\ \text{weight, ppg}\end{array} - \begin{array}{c}\text{mud weight}\\ \text{in use, ppg}\end{array}\right)(0.052)\left(\begin{array}{c}\text{casing}\\ \text{shoe}\\ \text{TVD, ft}\end{array}\right)$$

Example: Maximum allowable mud weight = 15.0 ppg (from leak-off test data)
Mud weight = 12.0 ppg
Casing seat TVD = 8000 ft

$$\text{MASP, psi} = (15.0 - 12.0) \times 0.052 \times 8000$$
$$\text{MASP} = 1248 \text{ psi}$$

Maximum Allowable Surface Pressure (MASP) Governed by Casing Burst Pressure

$$\text{MASP} = \begin{pmatrix} \text{casing} \\ \text{burst} \\ \text{pressure,} \\ \text{psi} \end{pmatrix} \times \begin{pmatrix} \text{safety} \\ \text{factor} \end{pmatrix} - \left(\begin{matrix} \text{mud} \\ \text{weight} \\ \text{in use,} \\ \text{ppg} \end{matrix} - \begin{matrix} \text{mud} \\ \text{weight} \\ \text{outside} \\ \text{casing,} \\ \text{ppg} \end{matrix} \right) (0.052) \begin{pmatrix} \text{casing} \\ \text{shoe} \\ \text{TVD,} \\ \text{ft} \end{pmatrix} \tag{4.62}$$

Example: Casing—10¾ 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%

$$\text{MASP} = (6070 \times 80\%) - [(12.0 - 9.4) \times 0.052 \times 8000]$$
$$\text{MASP} = 4856 \times (2.6 \times 0.052 \times 8000)$$
$$\text{MASP} = 3774 \text{ psi}$$

4.8 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):

$$\begin{matrix} \text{Reduced casing} \\ \text{pressure, psi} \end{matrix} = \begin{pmatrix} \text{shut-in casing} \\ \text{pressure, psi} \end{pmatrix} - \begin{pmatrix} \text{choke line} \\ \text{pressure loss, psi} \end{pmatrix} \tag{4.63}$$

Example: Shut-in casing (annulus) pressure (SICP) = 800 psi
Choke line pressure loss (CLPL) = 300 psi

Reduced casing pressure, psi = 800 psi – 300 psi
Reduced casing pressure = 500 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
	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

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 four steps on the chart:

$$\text{psi/line} = \frac{\text{(CLPL)300 psi}}{4} = 75 \text{ psi}$$

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	

Maximum Allowable Mud Weight, ppg, Subsea Stack as Derived from Leak-Off Test Data

$$\begin{array}{l}\text{Maximum}\\ \text{allowable}\\ \text{mud weight,}\\ \text{ppg}\end{array} = \left(\begin{array}{l}\text{leak-off}\\ \text{test}\\ \text{pressure,}\\ \text{psi}\end{array}\right) \div 0.052 \div \left(\begin{array}{l}\text{TVD, ft}\\ \text{RKB to}\\ \text{casing}\\ \text{shoe}\end{array}\right) + \left(\begin{array}{l}\text{mud}\\ \text{weight}\\ \text{in use,}\\ \text{ppg}\end{array}\right) \tag{4.64}$$

Example: Leak-off test pressure = 800 psi
TVD from rotary bushing to casing shoe = 4000 ft
Mud weight in use = 9.2 ppg

$$\text{Maximum allowable mud weight, ppg} = 800 \div 0.052 \div 4000 + 9.2$$
$$\text{Maximum allowable mud weight, ppg} = 13.0 \text{ ppg}$$

Maximum Allowable Shut-In Casing (Annulus) Pressure from Equation (4.22)

$$\text{MASICP} = \left(\begin{array}{c}\text{maximum}\\ \text{allowable mud}\\ \text{weight, ppg}\end{array} - \begin{array}{c}\text{mud}\\ \text{weight in}\\ \text{use, ppg}\end{array}\right)(0.052)\left(\begin{array}{c}\text{TVD, ft}\\ \text{RKB to}\\ \text{casing shoe}\end{array}\right)$$

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

$$\text{MASICP} = (13.3 \text{ ppg} - 11.5 \text{ ppg}) \times 0.052 \times 4000 \text{ ft}$$
$$\text{MASICP} = 374$$

Casing Burst Pressure—Subsea Stack

Step 1

Determine the internal yield pressure of the casing from the "Dimensions and Strengths" section in a 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%.

$$\text{Correct internal yield pressure, psi} = (\text{internal yield pressure, psi}) \times \text{SF}$$

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.

$$\text{HP, psi} = \begin{pmatrix}\text{mud weight}\\ \text{in use, ppg}\end{pmatrix} \times 0.052 \times \begin{pmatrix}\text{TVD, ft from}\\ \text{RKB to mud line}\end{pmatrix} \tag{4.65}$$

Step 4

Determine the hydrostatic pressure exerted by the seawater:

$$\text{HPsw} = \text{seawater weight, ppg} \times 0.052 \times \text{depth of seawater, ft}$$

Step 5

Determine casing burst pressure (CBP):

$$\text{CBP} \times \begin{pmatrix}\text{corrected internal}\\ \text{yield pressure, psi}\end{pmatrix} - \begin{pmatrix}\text{HP of mud in use, psi} +\\ \text{HP of seawater, psi}\end{pmatrix} \tag{4.66}$$

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:

9⅝ in. casing—C-75, 53.5 lb/ft
Internal yield pressure = 7430 psi

Step 2

Correct internal yield pressure for safety factor:

Corrected internal yield pressure = 7430 psi × 0.80
Corrected internal yield pressure = 5944 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:

$$\text{Casing burst pressure, psi} = 5944\ \text{psi} + 679\ \text{psi}$$
$$\text{Casing burst pressure} = 5817\ \text{psi}$$

Calculate choke line pressure loss (CLPL), psi

$$\text{CLPL} = \frac{0.000061 \times \text{MW, ppg (length, ft) } (\text{GPM}^{1.86})}{\text{choke line ID, in.}^{4.86}} \tag{4.67}$$

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.

$$\text{CLPL} = \frac{0.000061\ (14.0\ \text{ppg})\ (2000\ \text{ft})\ (225^{1.86})}{2.5^{4.86}}$$

$$\text{CLPL} = \frac{40{,}508{,}611}{85.899066}$$

$$\text{CLPL} = 471.58\ \text{psi}$$

Velocity, ft/min, through the Choke Line

$$\text{V, ft/min} = \frac{24.5 \times \text{gpm}}{\text{ID, in.}^2} \tag{4.68}$$

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.

$$\text{V, ft/min} = \frac{24.5\ (225)}{2.5^2}$$

$$\text{V} = 882\ \text{ft/min}$$

Adjusting Choke Line Pressure Loss for a Higher Mud Weight

$$\text{New CLPL} = (\text{higher mud weight, ppg} \times \text{CLPL}) \div \text{old mud weight, ppg} \tag{4.69}$$

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

$$\text{New CLPL} = 15.0\ \text{ppg} \times 300\ \text{psi} \div 13.5\ \text{ppg}$$

$$\text{New CLPL} = 333.33\ \text{psi}$$

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:

$$\text{psi} = (450 \times 0.445) + (0.68 \times \text{“y”})$$
$$\text{psi} = 200.25 + 0.68\text{“y”}$$

Step 2

Determine hydrostatic pressure of mud column:

$$\text{psi} = 90\ \text{ppg} \times 0.052 \times (60 + 450 + \text{“y”})$$
$$\text{psi} = [9.0 \times 0.052 \times (60 + 450)] + (9.0 \times 0.052 \times \text{“y”})$$
$$\text{psi} = 238.68 + 0.468\text{“y”}$$

Step 3

Minimum conductor casing setting depth:

$$200.25 + 0.68\text{“y”} = 238.68 + 0.468\text{“y”}$$
$$0.68\text{“y”} - 0.468\text{“y”} = 238.68 - 200.25$$
$$0.212\text{“y”} = 38.43$$
$$\text{“y”} = \frac{38.43}{0.212}$$
$$\text{“y”} = 181.3\ \text{ft}$$

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 seat at	= 1225 ft RKB
Seawater gradient	= 0.445 psi/ft
Formation fracture gradient	= 0.58 psi/ft

Step l

Determine total pressure at casing seat:

psi = [0.58(1225 − 600 − 75)] + (0.445 × 600)
psi = 319 + 267
psi = 586

Step 2

Determine maximum mud weight:

Max mud wt = 586 psi ÷ 0.052 ÷ 1225 ft
Max mud wt = 9.2 ppg

Reduction in Bottomhole Pressure if Riser Is Disconnected

Example: Use the following data and determine the reduction in bottom hole pressure if the riser is disconnected:

Data:

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:

$$\text{BHP} = (0.445 \times 700) + [9.0 \times 0.052 \times (2020 - 700 - 75)]$$
$$\text{BHP} = 311.5 + 582.7$$
$$\text{BHP} = 894.2 \text{ psi}$$

Step 3

Determine bottomhole pressure reduction:

$$\text{BHP reduction} = 945.4 \text{ psi} - 894.2 \text{ psi}$$
$$\text{BHP reduction} = 51.2 \text{ psi}$$

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:

$$\text{psi} = 12.0 \text{ ppg} \times 0.052 \times (1500 + 75)$$
$$\text{psi} = 982.8$$

Step 2

Hydrostatic pressure exerted by gas influx:

$$\text{psi} = 0.12 \text{ psi/ft} \times 1200 \text{ ft}$$
$$\text{psi} = 144$$

Step 3

Hydrostatic pressure of original mud below gas influx:

$$\text{psi} = 12.0 \text{ ppg} \times 0.052 \times 5500 \text{ ft}$$
$$\text{psi} = 3432$$

Step 4

Hydrostatic pressure of kill weight mud:

$$\text{psi} = 12.7 \text{ ppg} \times 0.052 \times (13{,}500 - 5500 - 1200 - 1500 - 75)$$
$$\text{psi} = 12.7 \text{ ppg} \times 0.052 \times 5225$$
$$\text{psi} = 3450.59$$

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

4.9 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:

1. Tubing in the well with a packer set. No communication exists between tubing and annulus.
2. Tubing in the well, influx in the annulus, and for some reason cannot circulate through the tubing.
3. 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.)
4. 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 #1.

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	= 2⅞ 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:

$$\begin{array}{l}\text{Rate of gas} \\ \text{migration, ft/hr}\end{array} = \begin{pmatrix}\text{increase in} \\ \text{pressure per/hr, psi}\end{pmatrix} \div \begin{pmatrix}\text{completion fluid} \\ \text{gradient, psi/ft}\end{pmatrix} \tag{4.70}$$

Solution:

Calculate the maximum allowable tubing (surface) pressure (MATP) for formation fracture:

a) MATP, initial, with influx in the tubing:

$$\text{MATP, initial} = \left[\begin{pmatrix}\text{fracture}\\\text{gradient,}\\\text{psi/ft}\end{pmatrix}\begin{pmatrix}\text{depth of}\\\text{perforations,}\\\text{ft}\end{pmatrix}\right] - \begin{pmatrix}\text{tubing}\\\text{hydrostatic}\\\text{pressure, psi}\end{pmatrix}$$

$$\text{MATP, initial} = (0.862\text{ psi/ft} \times 6480\text{ ft}) - 326\text{ psi}$$

$$\text{MATP, initial} = 5586\text{ psi} - 326\text{ psi}$$

$$\text{MATP, initial} = 5260\text{ psi} \tag{4.71}$$

b) MATP, final, with kill fluid in tubing:

$$\text{MATP, final} = \left[\begin{pmatrix}\text{fracture}\\\text{gradient,}\\\text{psi/ft}\end{pmatrix}\begin{pmatrix}\text{depth of}\\\text{perforations,}\\\text{ft}\end{pmatrix}\right] - \begin{pmatrix}\text{tubing}\\\text{hydrostatic}\\\text{pressure with}\\\text{kill fluid, psi}\end{pmatrix}$$

$$\text{MATP, final} = (0.862 \times 6480) - (8.4 \times 0.052 \times 6480)$$

$$\text{MATP, final} = 5586\text{ psi} - 2830\text{ psi}$$

$$\text{MATP, final} = 2756\text{ psi} \tag{4.72}$$

Determine tubing capacity:

$$\text{Tubing capacity, bbl} = \text{tubing length, ft} \times \text{tubing capacity, bbl/ft}$$

$$\text{Tubing capacity, bbl} = 6480\text{ ft} \times 0.00579\text{ bbl/ft}$$

$$\text{Tubing capacity} = 37.5\text{ bbl} \tag{4.73}$$

Plot these values as shown below:

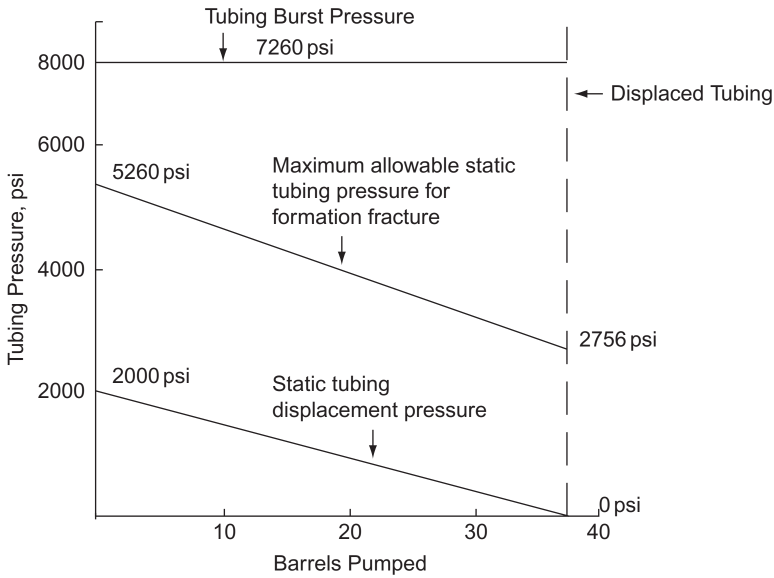

Figure 4-3. Tubing pressure profile.

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 the 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 to 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 describe this procedure:

TVD	= 6500 ft
Depth of perforations	= 6450 ft
SITP	= 2830 psi
Tubing	= 2⅞ 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:

$$\text{psi/bbl} = \text{tubing capacity, ft/bbl} \times 0.052 \times \text{kill weight fluid, ppg}$$
$$\text{psi/bbl} = 172.76 \text{ ft/bbl} \times 0.052 \times 9.0 \text{ ppg}$$
$$\text{psi/bbl} = 80.85 \tag{4.74}$$

For each barrel pumped, the SITP will be reduced by 80.85 psi.

Calculate tubing capacity, bbl, to the perforations:

$$\text{bbl} = \text{tubing capacity, bbl/ft} \times \text{depth to perforations, ft}$$
$$\text{bbl} = 0.00579 \text{ bbl/ft} \times 6450 \text{ ft} \tag{4.75}$$
$$\text{bbl} = 37.3 \text{ bbl}$$

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 ¼ 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 the 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.

4.10 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

SI Units

This is a constant bottomhole pressure method of well control, and it is the simplest method. In order to use this method, the bit must be on the 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 the 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

SI 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:

$$\text{Hp/bbl} = \text{mud gradient, psi/ft} \div \text{annular capacity, bbl/ft} \tag{4.76}$$

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 the 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.

$$\text{Hp/m}^3 = \text{mud gradient, kPa/m} \div \text{annular capacity, m}^3\text{/m} \tag{4.77}$$

3. Calculate the volume to bleed per cycle:

$$\text{Volume, m} = \text{Pw} + \text{Hp/m}^3 \tag{4.78}$$

4. Allow the 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.

4.11 Gas Lubrication

Gas lubrication is the process of removing gas from beneath the BOP stack while maintaining constant bottomhole 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

SI 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:

$$P_3 = P_1{}^2 \div P_2 \tag{4.79}$$

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.

4.12 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 Drillers 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 tank occurs.

Trip tank measures gas expansion similar to the volumetric method. Pressure is stepped up as in the volumetric method.

4.13 Worksheet

1. Select a working pressure, Pw. Recommended Pw = 50–100 psi.
2. Calculate the hydrostatic pressure:

$$\text{Hp/bbl} = \text{pressure gradient, psi/ft} \div \text{upper annular capacity, bbl/ft} \tag{4.80}$$

3. Calculate influx length in the open hole:

$$L_1 = \text{influx volume, bbl} \div \text{open hole capacity, bbl/ft} \tag{4.81}$$

4. Calculate influx length after the BHA has penetrated the influx:

$$L_2 = \text{influx volume, bbl} \div \text{annular capacity(drill collars/open hole), bbl/ft} \tag{4.82}$$

5. Calculate the pressure increase due to bubble penetration, Ps:

$$Ps = (L_1 - L_2) \times \text{(gradient of mud), psi/ft} \times 0.1\text{psi/ft} \tag{4.83}$$

6. Calculate the Pchoke values:

$$\text{Pchoke}_1 = \text{SICP} + \text{Pw} + \text{Ps} \tag{4.84}$$

$$\text{Pchoke}_2 = \text{Pchoke}_1 + \text{Pw} \tag{4.85}$$

$$\text{Pchoke}_3 = \text{Pchoke}_2 + \text{Pw} \tag{4.86}$$

7. Calculate the incremental volume (Vm) of hydrostatic equal to Pw in the upper annulus:

$$\text{Vm} = \text{Pw} \div \text{Hp/bbl} \tag{4.87}$$

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, 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 Drillers Method.

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CHAPTER FIVE

ENGINEERING CALCULATIONS

5.0 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.:

$$\text{Nozzle area, sq. in.} = \frac{N_1^2 + N_2^2 + N_3^2}{1303.8} \tag{5.1}$$

2. Bit nozzle pressure loss, psi (Pb):

$$\text{Pb} = \frac{\text{gpm}^2 \times \text{MW, ppg}}{10{,}858 \times \text{nozzle area, sq. in.}^2} \tag{5.2}$$

3. Total pressure losses except bit nozzle pressure loss, psi (Pc):

$$\text{Pc}_1 \text{ and } \text{Pc}_2 = \begin{array}{l}\text{circulating}\\ \text{pressure, psi}\end{array} - \begin{array}{l}\text{bit nozzle}\\ \text{pressure loss, psi}\end{array} \tag{5.3}$$

4. Determine slope of line M:

$$\text{M} = \frac{\log(\text{Pc}_1 \div \text{Pc}_2)}{\log(\text{Q}_1 \div \text{Q}_2)} \tag{5.4}$$

5. Optimum pressure losses (Popt)

a) For impact force:

$$\text{Popt} = \frac{2}{\text{M} + 2} \times \text{P max} \tag{5.5a}$$

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b) For hydraulic horsepower:

$$\text{Popt} = \frac{1}{\text{M} + 1} \times \text{P max} \tag{5.5b}$$

6. For optimum flow rate (Qopt):

a) For impact force:

$$\text{Qopt, gpm} = \left(\frac{\text{Popt}}{\text{P max}}\right)^{1/\text{M}} \times \text{Q1} \tag{5.6a}$$

b) For hydraulic horsepower:

$$\text{Qopt, gpm} = \left(\frac{\text{Popt}}{\text{P max}}\right)^{1/\text{M}} \times \text{Q1} \tag{5.6b}$$

7. To determine pressure at the bit (Pb):

$$\text{Pb} = \text{P max} - \text{Popt} \tag{5.7}$$

8. To determine nozzle area, sq. in.:

$$\text{Nozzle area, sq. in.} = \sqrt{\frac{\text{Qopt}^2 \times \text{MW, ppg}}{10{,}858 \times \text{P max}}} \tag{5.8}$$

9. To determine nozzles, 1/32 in. for three nozzles:

$$\text{Nozzles} = \sqrt{\frac{\text{nozzle area, sq. in.}}{3 \times 0.7854}} \times 32 \tag{5.9}$$

10. To determine nozzles, 1/32 in. for two nozzles:

$$\text{Nozzles} = \sqrt{\frac{\text{nozzle area, sq. in.}}{2 \times 0.7854}} \times 32 \tag{5.10}$$

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.:

$$\text{Nozzle area, sq. in.} = \frac{17^2 + 17^2 + 17^2}{1303.8}$$

$$\text{Nozzle area, sq. in.} = 0.664979$$

2. Bit nozzle pressure loss, psi (Pb):

$$Pb_1 = \frac{420^2 \times 13.0}{10{,}858 \times 0.664979^2}$$

$$Pb_1 = 478 \text{ psi}$$

$$Pb_2 = \frac{275^2 \times 13.0}{10{,}858 \times 0.664979^2}$$

$$Pb_2 = 205 \text{ psi}$$

3. Total pressure losses except bit nozzle pressure loss (Pc), psi:

$$Pc_1 = 3000 \text{ psi} - 478 \text{ psi}$$
$$Pc_1 = 2522 \text{ psi}$$

$$Pc_2 = 1300 \text{ psi} - 205 \text{ psi}$$
$$Pc_2 = 1095 \text{ psi}$$

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:

$$\text{Popt} = \frac{2}{1.97 + 2} \times 3000$$

$$\text{Popt} = 1511 \text{ psi}$$

b) For hydraulic horsepower:

$$\text{Popt} = \frac{1}{1.97 + 1} \times 3000$$

$$\text{Popt} = 1010 \text{ psi}$$

6. Determine optimum flow rate (Qopt):

a) For impact force:

$$\text{Qopt, gpm} = \left(\frac{1511}{3000}\right)^{1/1.97} \times 420$$

$$\text{Qopt} = 297\text{gpm}$$

b) For hydraulic horsepower:

$$\text{Qopt, gpm} = \left(\frac{1010}{3000}\right)^{1/1.97} \times 420$$

$$\text{Qopt} = 242 \text{ gpm}$$

7. Determine pressure losses at the bit (Pb):

   a) For impact force:

$$Pb = 3000 \text{ psi} - 1511 \text{ psi}$$
$$Pb = 1489 \text{ psi}$$

   b) For hydraulic horsepower:

$$Pb = 3000 \text{ psi} - 1010 \text{ psi}$$
$$Pb = 1990 \text{ psi}$$

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, 1/32 in.:

   a) For impact force:

$$\text{Nozzles} = \sqrt{\frac{0.26632}{3 \times 0.7854}} \times 32$$
$$\text{Nozzles} = 10.76$$

b) For hydraulic horsepower:

$$\text{Nozzles} = \sqrt{\frac{0.1877}{3 \times 0.7854}} \times 32$$

$$\text{Nozzles} = 9.03$$

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.

c) For impact force:

$0.76 \times 3 = 2.28$ rounded to 2

so: 1 jet = 10/32
2 jets = 11/32

d) For hydraulic horsepower:

$0.03 \times 3 = 0.09$ rounded to 0

so: 3 jets = 9/32 in.

10. Determine nozzles, 1/32 in. for two nozzles:

a) For impact force:

$$\text{Nozzles} = \sqrt{\frac{0.26632}{2 \times 0.7854}} \times 32$$

$$\text{Nozzles} = 13.18 \text{ sq. in.}$$

b) For hydraulic horsepower:

$$\text{Nozzles} = \sqrt{\frac{0.1877}{2 \times 0.7854}} \times 32$$

$$\text{Nozzles} = 11.06 \text{ sq. in.}$$

5.1 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):

$$AV = \frac{24.5 \times Q}{Dh^2 - Dp^2} \tag{5.11}$$

2. Jet nozzle pressure loss, psi (Pb):

$$Pb = \frac{156.5 \times Q^2 \times MW}{\left[(N_1)^2 + (N_2)^2 + (N_3)^2\right]^2} \tag{5.12}$$

3. System hydraulic horsepower available (Sys HHP):

$$SysHHP = \frac{\text{surface, psi} \times Q}{1714} \tag{5.13}$$

4. Hydraulic horsepower at bit (HHPb):

$$HHPb = \frac{Q \times Pb}{1714} \tag{5.14}$$

5. Hydraulic horsepower per square inch of bit diameter:

$$HHPb/\text{sq. in.} = \frac{HHPb \times 1.27}{\text{bit size}^2} \tag{5.15}$$

6. Percent pressure loss at bit (% psib):

$$\%\ psib = \frac{Pb}{\text{surface, psi}} \times 100 \tag{5.16}$$

7. Jet velocity, ft/sec (Vn):

$$Vn = \frac{417.2 \times Q}{(N_1)^2 + (N_2)^2 + (N_3)^2} \tag{5.17}$$

8. Impact force, lb, at bit (IF):

$$\text{IF} = \frac{(\text{MW})(\text{Vn})(\text{Q})}{1930} \tag{5.18}$$

9. Impact force per square inch of bit area (IF/sq. in.):

$$\text{IF/sq. in.} = \frac{\text{IF} \times 1.27}{\text{bit size}^2} \tag{5.19}$$

Nomenclature:

AV	= annular velocity, ft/min
Q	= circulation rate, gpm
Dh	= hole diameter, in.
Dp	= pipe or collar OD, in.
MW	= mud weight, ppg
N1; N2; N3	= jet nozzle sizes, 1/32 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:	Mud weight	= 12.0 ppg
	Circulation rate	= 520 gpm
	Nozzle size 1	= 12/32 in.
	Nozzle size 2	= 12/32 in.
	Nozzle size 3	= 12/32 in.
	Hole size	= 12¼ in.
	Drill pipe OD	= 5.0 in.
	Surface pressure	= 3000 psi

1. Annular velocity, ft/min:

$$\text{AV} = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$\text{AV} = \frac{12{,}740}{125.0625}$$

$$\text{AV} = 102 \text{ ft/min}$$

2. Jet nozzle pressure loss:

$$\text{Pb} = \frac{156.5 \times 520^2 \times 12.0}{\left(12^2 + 12^2 + 12^2\right)^2}$$

$$\text{Pb} = 2721 \text{ psi}$$

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:

$$IF = \frac{12.0 \times 502 \times 520}{1930}$$

$$IF = 1623\ lb$$

9. Impact force per square inch of bit area:

$$IF/sq.\ in. = \frac{1623 \times 1.27}{12.25^2}$$

$$IF/sq.\ in. = 13.7$$

5.2 Critical Annular Velocity and Critical Flow Rate

1. Determine n:

$$n = 3.32\ \log \frac{\theta 600}{\theta 300} \tag{5.20}$$

2. Determine K:

$$K = \frac{\theta 600}{1022^n} \tag{5.21}$$

3. Determine x:

$$x = \frac{81{,}600(Kp)(n)^{0.387}}{(Dh - Dp)^n\ MW} \tag{5.22}$$

4. Determine critical annular velocity:

$$AVc = (x)^{1/2-n} \tag{5.23}$$

5. Determine critical flow rate:

$$GPMc = \frac{AVc(Dh^2 - Dp^2)}{24.5} \tag{5.24}$$

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:

$$AVc = (1035)^{1/(2-0.79)}$$
$$AVc = (1035)^{0.8264}$$
$$AVc = 310 \text{ ft/min}$$

5. Determine critical flow rate:

$$GPMc = \frac{310(8.5^2 - 7.0^2)}{24.5}$$
$$GPMc = 294 \text{ gpm}$$

5.3 The "d" Exponent

The "d" exponent is derived from the general drilling equation:

$$R \div N = a(W^d \div D) \qquad (5.25)$$

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:

$$\text{"d"} = \log(R \div 60N) \div \log(12W \div 1000D) \qquad (5.26)$$

where: d = d exponent, dimensionless
R = penetration rate, ft/hr
N = rotary speed, rpm
W = weight on bit, 1000 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: $d_c = 1.64\ (9.0 \div 12.7)$
$d_c = 1.64 \times 0.71$
$d_c = 1.16$

5.4 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 cuttings net rise velocity are also calculated.

Method 1

Annular velocity, ft/min:

$$AV = \frac{24.5 \times Q}{Dh^2 - Dp^2} \tag{5.27}$$

Cuttings slip velocity, ft/min:

$$Vs = 0.45\left(\frac{PV}{(MW)(Dp)}\right)\left[\sqrt{\frac{36{,}800}{\left(\frac{PV}{(MW)(Dp)}\right)^2} \times (Dp)\left(\frac{DenP}{MW} - 1\right) + 1^{-1}}\right] \tag{5.28}$$

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 cuttings 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:

$$Vs = 0.45\left(\frac{13}{11 \times 0.25}\right)\left[\sqrt{\frac{36{,}800}{\left(\frac{13}{11 \times 0.25}\right)^2} \times 0.25\left(\frac{22}{11} - 1\right) + 1^{-1}}\right]$$

$$Vs = 0.45[4.727]\left[\sqrt{\frac{36{,}800}{[4.727]^2} \times 0.25 \times 1 + 1} - 1\right]$$

$$Vs = 2.12715\left(\sqrt{412.68639} - 1\right)$$

$$Vs = 2.12715 \times 19.3146$$

$$Vs = 41.085 \text{ ft/min}$$

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:

$$n = 3.32 \log \frac{\theta 600}{\theta 300} \tag{5.29}$$

2. Determine K:

$$K = \frac{\theta 300}{511^n} \tag{5.30}$$

3. Determine annular velocity, ft/min:

$$v = \frac{24.5 \times Q}{Dh^2 - Dp^2} \tag{5.31}$$

4. Determine viscosity (μ):

$$\mu = \left(\frac{2.4v}{Dh - Dp} \times \frac{2n + 1}{3n}\right)^n \left(\frac{200K(Dh - Dp)}{v}\right) \tag{5.32}$$

5. Slip velocity (Vs), ft/min:

$$Vs = \frac{(DensP - MW)^{0.667} \times 175 \times DiaP}{MW^{0.333} \times \mu^{0.333}} \tag{5.33}$$

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	= cuttings density, ppg
DiaP	= cuttings diameter, in.

Example: Using the data listed below, determine the annular velocity, cuttings slip velocity, and the cuttings net rise velocity:

Data:		
	Mud weight	= 11.0 ppg
	Plastic viscosity	= 13 cps
	Yield point	= 10 lb/100 ft^2
	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:

$$\mu = \left(\frac{2.4 \times 102}{12.25 - 5.0} \times \frac{2(0.64599) + 1}{3 \times 0.64599}\right)^{0.64599} \left(\frac{200 \times 0.4094 \times (12.25 - 5)}{102}\right)$$

$$\mu = \left(\frac{244.8}{7.25} \times \frac{2.92}{1.938}\right)^{0.64599} \times \frac{593.63}{102}$$

$$\mu = (33.76 \times 1.1827)^{0.64599} \times 5.82$$

$$\mu = 10.82 \times 5.82$$

$$\mu = 63 \text{ cps}$$

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

5.5 Surge and Swab Pressures

Method 1

1. Determine n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300} \tag{5.34}$$

2. Determine K:

$$K = \frac{\theta 300}{511^n} \tag{5.35}$$

3. Determine velocity, ft/min:

For plugged flow:

$$v = \left[0.45 + \frac{Dp^2}{Dh^2 - Dp^2}\right] Vp \tag{5.36}$$

For open pipe:

$$v = \left[0.45 + \frac{Dp^2 - Di^2}{Dh^2 - Dp^2 + Di^2}\right] Vp \tag{5.37}$$

4. Maximum pipe velocity:

$$Vm = 1.5 \times v \tag{5.38}$$

5. Determine pressure losses:

$$Ps = \left(\frac{2.4\ Vm}{Dh - Dp} \times \frac{2n + 1}{3n}\right)^n \times \frac{KL}{300(Dh - Dp)} \tag{5.39}$$

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:

Data:

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. × 2¾ in. 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 (bottom-hole 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:

$$v = \left[0.45 + \frac{Dp^2}{Dh^2 - Dp^2}\right] Vp \tag{5.40}$$

2. Maximum pipe velocity (Vm):

$$Vm = v \times 1.5 \tag{5.41}$$

3. Calculate n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300} \tag{5.42}$$

4. Calculate K:

$$K = \log \frac{\theta 300}{511^n} \tag{5.43}$$

5. Calculate the shear rate (Ym) of the mud moving around the pipe:

$$Ym = \frac{2.4 \times Vm}{Dh - Dp} \tag{5.44}$$

6. Calculate the shear stress (T) of the mud moving around the pipe:

$$T = K(Ym)^n \tag{5.45}$$

7. Calculate the pressure (Ps) decrease for the interval:

$$\text{Ps} = \frac{3.33\text{T}}{\text{Dh} - \text{Dp}} \times \frac{\text{L}}{1000} \tag{5.46}$$

B. Surge pressure around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$\text{v} = \left[0.45 + \frac{\text{Dp}^2}{\text{Dh}^2 - \text{Dp}^2}\right]\text{Vp} \tag{5.47}$$

2. Calculate maximum pipe velocity (Vm):

$$\text{Vm} = \text{v} \times 1.5 \tag{5.48}$$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flowrate (Q):

$$\text{Q} = \frac{\text{Vm}\left[(\text{Dh})^2 - (\text{Dp})^2\right]}{24.5} \tag{5.49}$$

4. Calculate the pressure loss for each interval (Ps):

$$\text{Ps} = \frac{0.000077 \times \text{MW}^{0.8} \times \text{Q}^{1.8} \times \text{PV}^{0.2} \times \text{L}}{(\text{Dh} - \text{Dp})^3 \times (\text{Dh} + \text{Dp})^{1.8}} \tag{5.50}$$

C. Total surge pressures converted to mud weight:

$$\begin{aligned}&\text{Total surge (or swab) pressures:}\\&\text{psi} = \text{Ps(drill pipe)} + \text{Ps(drill collars)}\end{aligned} \tag{5.51}$$

D. If surge pressure is desired:

$$\text{SP, ppg} = \text{Ps} \div [0.052(\text{TVD, ft})] + \text{MW, ppg} \tag{5.52}$$

E. If swab pressure is desired:

$$SP, ppg = Ps \div [0.052(TVD,\ ft)] - MW,\ ppg \qquad (5.53)$$

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 ft^2
Hole diameter	= 7⅞ in.
Drill pipe OD	= 4½ in.
Drill pipe length	= 14,300 ft
Drill collar OD	= 6¼ 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:

$$v = \left[0.45 + \frac{(4.5)^2}{7.875^2 - 4.5^2}\right]270$$

$$v = [0.45 + 0.4848]270$$

$$v = 253\ ft/min$$

2. Calculate maximum pipe velocity (Vm):

$$Vm = 253 \times 1.5$$
$$Vm = 379\ ft/min$$

NOTE: Determine n and K from the plastic viscosity and yield point as follows:

$$PV + YP = \theta 300\ reading$$

$$\theta 300\ reading + PV = \theta 600\ reading$$

Example: PV = 60
YP = 20

60 + 20 = 80 (θ300 reading)
80 + 60 = 140 (θ600 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:

$$Ps = \frac{0.000077 \times 15^{0.8} \times 816^{1.8} \times 60^{0.2} \times 700}{(7.875 - 6.25)^3 (7.875 + 6.25)^{1.8}}$$

$$Ps = \frac{185{,}837.9}{504.126}$$

$$Ps = 368.6 \text{ psi}$$

C. Total pressures:

$$psi = 672.9 \text{ psi} + 368.6 \text{ psi}$$
$$psi = 1041.5 \text{ psi}$$

D. Pressure converted to mud weight, ppg:

$$\text{ppg} = 1041.5 \text{ psi} \div [0.052(15{,}000 \text{ ft})]$$
$$\text{ppg} = 1.34$$

E. If surge pressure is desired:

$$\text{Surge pressure, ppg} = 15.0 \text{ ppg} + 1.34 \text{ ppg}$$
$$\text{Surge pressure} = 16.34 \text{ ppg}$$

F. If swab pressure is desired:

$$\text{Swab pressure, ppg} = 15.0 \text{ ppg} - 1.34 \text{ ppg}$$
$$\text{Swab pressure} = 13.66 \text{ ppg}$$

5.6 Equivalent Circulation Density (ECD)

1. Determine n:

$$n = 3.32 \log \frac{\theta 600}{\theta 300} \tag{5.54}$$

2. Determine K:

$$K = \frac{\theta 300}{511^n} \tag{5.55}$$

3. Determine annular velocity (v), ft/min:

$$v = \frac{24.5 \times Q}{Dh^2 - Dp^2} \tag{5.56}$$

4. Determine critical velocity (Vc), ft/min:

$$Vc = \left(\frac{3.878 \times 10^4 \times K}{MW}\right)^{\frac{1}{2-n}} \left(\frac{2.4}{Dh - Dp} \times \frac{2n+1}{3n}\right)^{\frac{n}{2-n}} \tag{5.57}$$

5. Pressure loss for laminar flow (Ps), psi:

$$\text{Ps} = \left(\frac{2.4\text{v}}{\text{Dh} - \text{Dp}} \times \frac{2\text{n} + 1}{3\text{n}}\right)^{\text{n}} \times \frac{\text{KL}}{300(\text{Dh} - \text{Dp})} \tag{5.58}$$

6. Pressure loss for turbulent flow (Ps), psi:

$$\text{Ps} = \frac{7.7 \times 10^{-5} \times \text{MW}^{0.8} \times \text{Q}^{1.8} \times \text{PV}^{0.2} \times \text{L}}{(\text{Dh} - \text{Dp})^3 \ (\text{Dh} + \text{Dp})^{1.8}} \tag{5.59}$$

7. Determine equivalent circulating density (ECD), ppg:

$$\text{ECD, ppg} = [\text{Ps} \div 0.052(\text{TVD, ft})] + \text{OMW, ppg} \tag{5.60}$$

Example: Equivalent circulating density (ECD), ppg:

Data:

Mud weight	=	12.5 ppg
Plastic viscosity	=	24 cps
Yield point	=	12 lb/100 ft^2
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:

$$\text{n} = 3.32 \log \left(\frac{60}{36}\right)$$

$$\text{n} = 0.7365$$

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:

$$Vc = \left(\frac{3.878 \times 10^4 \times .3644}{12.5}\right)^{\frac{1}{2-.7365}} \left(\frac{2.4}{8.5 - 5} \times \frac{2(.7365) + 1}{3(.7365)}\right)^{\frac{.7365}{2-.7365}}$$

$$Vc = (1130.5)^{0.791}(0.76749)^{0.5829}$$

$$Vc = 260 \times 0.857$$

$$Vc = 223 \text{ ft/min}$$

4b. Determine critical velocity (Vc), ft/min, around drill collars:

$$Vc = \left(\frac{3.878 \times 10^4 \times .3644}{12.5}\right)^{\frac{1}{2-.7365}} \left(\frac{2.4}{8.5 - 6.5} \times \frac{2(.7365) + 1}{3(.7365)}\right)^{\frac{.7365}{2-.7365}}$$

$$Vc = (1130.5)^{0.791}(1.343)^{0.5829}$$

$$Vc = 260 \times 1.18756$$

$$Vc = 309 \text{ ft/min}$$

Therefore:

Drill pipe: 207 ft/min (v) is less than 223 ft/min (Vc) laminar flow, so use equation (5.X) for pressure loss.

Drill collars: 327 ft/min (v) is greater than 309 ft/min (Vc) turbulent flow, so use equation (5.X) for pressure loss.

5. Pressure loss opposite drill pipe:

$$\text{Ps} = \left[\frac{2.4 \times 207}{8.5 - 5.0} \times \frac{2(.7365) + 1}{3(.7365)}\right]^{.7365} \times \frac{.3644 \times 11{,}300}{300(8.5 - 5.0)}$$

$$\text{Ps} = (141.9 \times 1.11926)^{.7365} \times 3.9216$$

$$\text{Ps} = 41.78 \times 3.9216$$

$$\text{Ps} = 163.8 \text{ psi}$$

6. Pressure loss opposite drill collars:

$$\text{Ps} = \frac{7.7 \times 10^{-5} \times 12.5^{0.8} \times 400^{1.8} \times 24^{0.2} \times 700}{(8.5 - 6.5)^3 (8.5 + 6.5)^{1.8}}$$

$$\text{Ps} = \frac{37{,}056.7}{8 \times 130.9}$$

$$\text{Ps} = 35.4 \text{ psi}$$

Total pressure losses:

$$\text{psi} = 163.8 \text{ psi} + 35.4 \text{ psi}$$

$$\text{psi} = 199.2 \text{ psi}$$

7. Determine equivalent circulating density (ECD), ppg:

$$\text{ECD, ppg} = 199.2 \text{ psi} \div [0.052(12{,}000 \text{ ft})] + 12.5 \text{ ppg}$$

$$\text{ECD} = 12.82 \text{ ppg}$$

5.7 Fracture Gradient Determination—Surface Applications

Method 1: Matthews and Kelly Method

$$F = P/D + [Ki\ (\sigma/D)] \tag{5.61}$$

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:

$$\sigma = S - P \tag{5.62}$$

3. Determine the depth for determining Ki by:

$$D = \frac{\sigma}{0.535} \tag{5.63}$$

4. From Matrix Stress Coefficient chart, determine K (see Figure 5-1).

5. Determine fracture gradient, psi/ft:

$$F = \frac{P}{D} + Ki \times \frac{\sigma}{D} \tag{5.64}$$

6. Determine fracture pressure, psi:

$$F, \text{psi} = \nabla F(D) \tag{5.65}$$

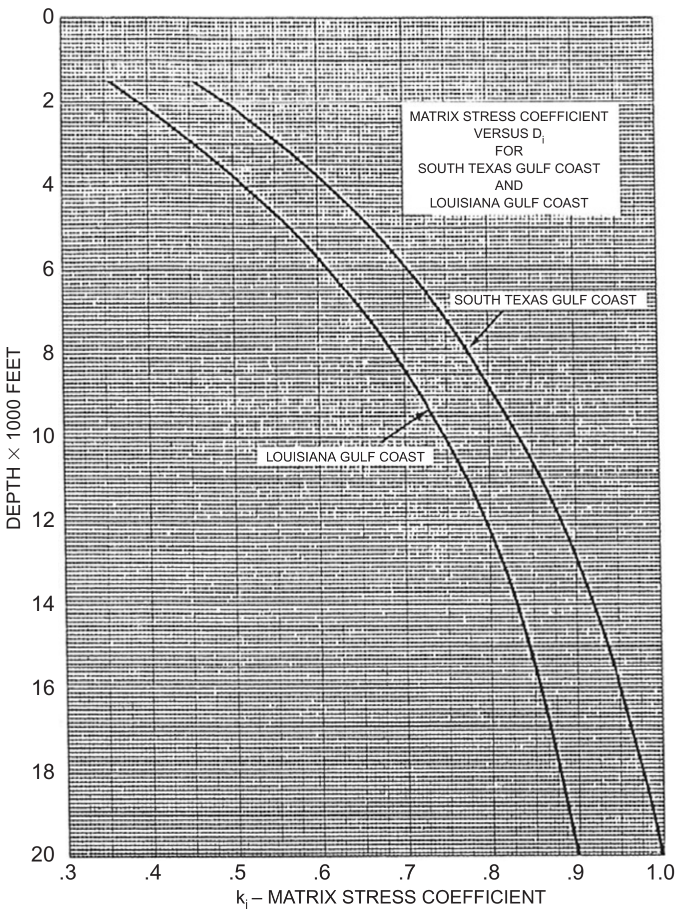


Figure 5-1. Matrix stress coefficient chart.

7. Determine maximum mud density, ppg:

$$\text{MW, ppg} = \frac{\nabla F}{0.052} \tag{5.66}$$

Example: Casing setting depth = 12,000 ft
Formation pore pressure = 12.0 ppg
(Louisiana Gulf Coast)

1. $P = 12.0 \text{ ppg} \times 0.052 \times 12{,}000 \text{ ft}$

   $P = 7488 \text{ psi}$

2. $\sigma = 12{,}000 \text{ psi} - 7488 \text{ psi}$

   $\sigma = 4512 \text{ psi}$

3. $$D = \frac{4512 \text{ psi}}{0.535}$$

   $D = 8434 \text{ ft}$

4. From chart = Ki = 0.79 psi/ft

5. $$\nabla F = \frac{7488}{12{,}000} + 0.79 \times \frac{4512}{12{,}000}$$

   $\nabla F = 0.624 \text{ psi/ft} + 0.297 \text{ psi/ft}$

   $\nabla F = 0.92 \text{ psi/ft}$

6. Fracture pressure, psi $= 0.92 \text{ psi/ft} \times 12{,}000 \text{ ft}$

   Fracture pressure $= 11{,}040 \text{ psi}$

7. $$\text{Maximum mud density, ppg} = \frac{0.92 \text{ psi/ft}}{0.052}$$

   Maximum mud density $= 17.69 \text{ ppg}$

Method 2: Ben Eaton Method

$$F = \left(\frac{S}{D} - \frac{Pf}{D}\right)\left(\frac{y}{1-y}\right) + \left(\frac{Pf}{D}\right) \tag{5.67}$$

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 Stress 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 equation (5.67).
5. Determine fracture pressure, psi:

$$\text{psi} = \nabla F \times D \tag{5.68}$$

6. Determine maximum mud density, ppg:

$$\text{ppg} = \frac{\nabla F}{0.052} \tag{5.69}$$

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. $Pf/D = 12.0 \text{ ppg} \times 0.052 = 0.624$ psi/ft
3. Poisson's Ratio from chart = 0.47 psi/ft
4. Determine fracture gradient:

$$\nabla F = (0.96 - 0.6243)\left(\frac{0.47}{1 - 0.47}\right) + 0.624$$

$$\nabla F = 0.336 \times 0.88679 + 0.624$$

$$\nabla F = 0.29796 + 0.624$$

$$\nabla F = 0.92 \text{ psi/ft}$$

5. Determine fracture pressure:

$$\text{psi} = 0.92 \text{ psi/ft} \times 12{,}000 \text{ ft}$$

$$\text{psi} = 11{,}040$$

6. Determine maximum mud density:

$$\text{pg} = \frac{0.92\ \text{psi/ft}}{0.052}$$

$$\text{ppg} = 17.69$$

5.8 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 flow line 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:

   $$\text{HPsw} = 8.9\ \text{ppg} \times 0.052 \times 2000\ \text{ft}$$

   $$\text{HPsw} = 926\ \text{psi}$$

   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:

   $$\text{Equivalent feet} = \frac{926\ \text{psi}}{0.92\ \text{psi/ft}}$$

   $$\text{Equivalent feet} = 1006$$

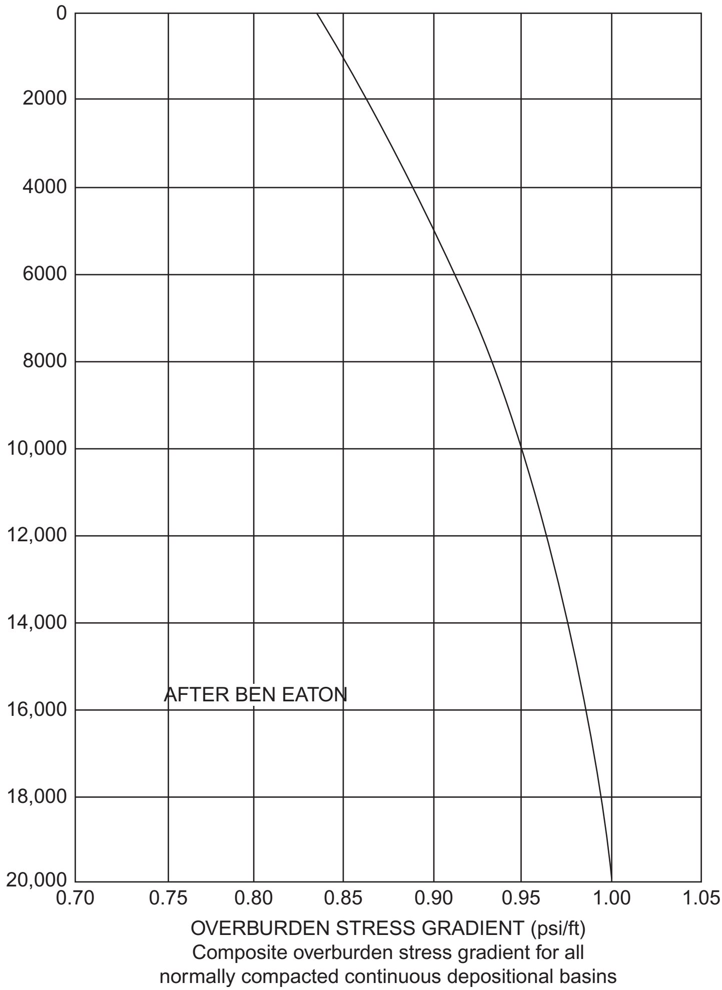


Figure 5-2. Eaton's Overburden Stress Chart.

2. Determine depth for fracture gradient determination:

$$\text{Depth, ft} = 4000 \text{ ft} + 1006 \text{ ft}$$
$$\text{Depth} = 5006 \text{ ft}$$

3. Using Eaton's Fracture Gradient Chart, determine the fracture gradient at a depth of 5006 ft:

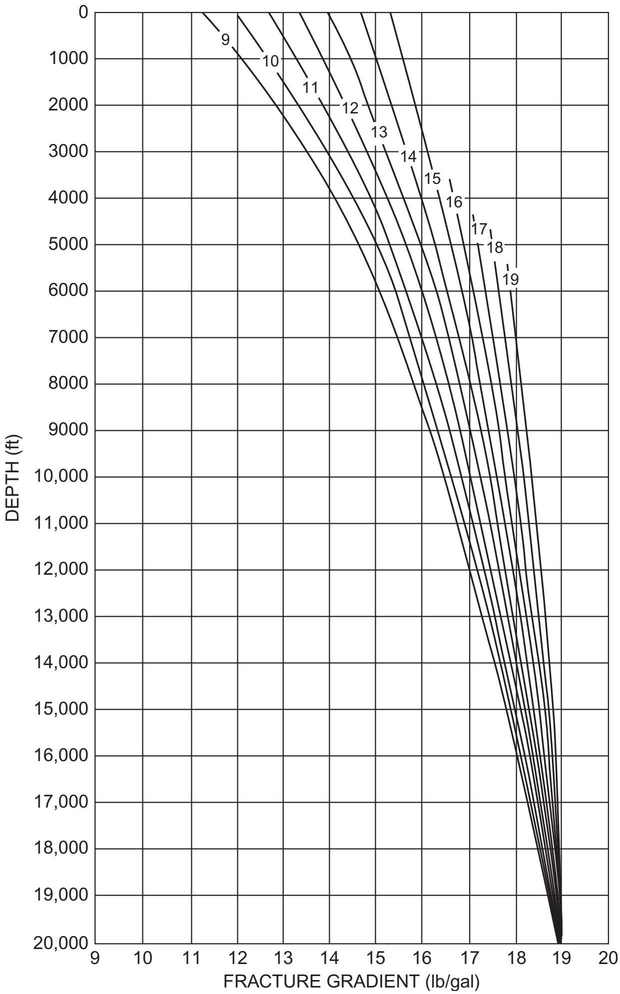


Figure 5-3. Eaton's Fracture Gradient Chart.

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:

$psi = 14.7\ ppg \times 0.052 \times 5006\ ft$
$psi = 3827$

5. Convert the fracture gradient relative to the flow line:

$\nabla Fc = 3827\ psi \div [0.052(6100\ ft)]$
$\nabla Fc = 12.06\ ppg$

where ∇Fc is the fracture gradient, corrected for water depth, and air gap.

5.9 Directional Drilling Calculations

5.9.1 Directional Survey Calculations

The following are the two most commonly used methods to calculate directional surveys:

1. **Angle Averaging Method**

$$\text{North} = \text{MD} \times \sin\frac{(\text{I1} + \text{I2})}{2} \times \cos\frac{(\text{A1} + \text{A2})}{2} \tag{5.70}$$

$$\text{East} = \text{MD} \times \sin\frac{(\text{I1} + \text{I2})}{2} \times \sin\frac{(\text{A1} + \text{A2})}{2} \tag{5.71}$$

$$\text{Vert} = \text{MD} \times \cos\frac{(\text{I1} + \text{I2})}{2} \tag{5.72}$$

2. **Radius of Curvature Method**

$$\text{North} = \frac{\text{MD}(\cos \text{I1} - \cos \text{I2})(\sin \text{A2} - \sin \text{A1})}{(\text{I2} - \text{I1})(\text{A2} - \text{A1})} \tag{5.73}$$

$$\text{East} = \frac{\text{MD}(\cos \text{I1} - \cos \text{I2})(\cos \text{A1} - \cos \text{A2})}{(\text{I2} - \text{I1})(\text{A2} - \text{A1})} \tag{5.74}$$

$$\text{Vert} = \frac{\text{MD}(\sin \text{I2} - \sin \text{I1})}{(\text{I2} - \text{I1})} \tag{5.75}$$

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:

$$\text{North} = \frac{300(\cos 4 - \cos 8)(\sin 35 - \sin 10)}{(8-4)(35-10)}$$

$$= \frac{300(.99756 - .990268)(.57357 - .173648)}{4 \times 25}$$

$$= \frac{.874629}{100}$$

$$= 0.008746 \times 57.3^2$$

$$\text{North} = 28.56 \text{ ft}$$

$$\text{East} = \frac{300(\cos 4 - \cos 8)(\cos 10 - \cos 35)}{(8-4)(35-10)}$$

$$= \frac{300(.99756 - .99026)(.9848 - .81915)}{4 \times 25}$$

$$= \frac{300(.0073)(.16565)}{100}$$

$$= \frac{0.36277}{100}$$

$$= 0.0036277 \times 57.3^2$$

$$\text{East} = 11.91 \text{ ft}$$

$$\text{Vert} = \frac{300(\sin 8 - \sin 4)}{(8-4)}$$

$$= \frac{300(.13947 \times .069756)}{4}$$

$$= \frac{300 \times .069414}{4}$$

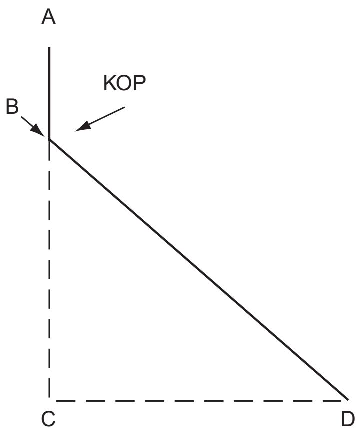
$$= 5.20605 \times 57.3$$

$$\text{Vert} = 298.3 \text{ ft}$$

5.9.2 Deviation/Departure Calculation

Deviation is defined as the 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:

$$\text{CD, ft} = \sin \text{I} \times \text{BD} \tag{5.76}$$

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):

$$\begin{aligned}\text{CD, ft} &= \sin 20 \times 6000\text{ ft}\\ &= 0.342 \times 6000\text{ ft}\\ \text{CD} &= 2052\text{ ft}\end{aligned}$$

From this calculation, the measured depth (MD) is 2052 ft away from vertical.

5.9.3 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:

$$\text{DLS} = \{\cos^{-1}[(\cos \text{I1} \times \cos \text{I2}) + (\sin \text{I1} \times \sin \text{I2}) \times \cos(\text{A2} - \text{A1})]\} \times \frac{100}{\text{CL}} \quad (5.77)$$

For metric calculation, substitute $\times \dfrac{30}{\text{CL}}$

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

$$\text{DLS} = \{\cos^{-1}[(\cos 13.5 \times \cos 14.7) + (\sin 13.5 \times \sin 14.7 \times \cos(19 - 10)]\} \times \frac{100}{31}$$

$$\text{DLS} = \{\cos^{-1}[(.9723699 \times .9672677) + (.2334453 \times .2537579 \times .9876883)]\} \times \frac{100}{31} \quad (5.78)$$

$$\text{DLS} = \left\{\cos^{-1}[(.940542) + (.0585092)]\right\} \times \frac{100}{31}$$

$$\text{DLS} = 2.4960847 \times \frac{100}{31}$$

$$\text{DLS} = 8.051886 \text{ degrees/100 ft}$$

Method 2

This method of calculating dogleg severity is based on the tangential method:

$$\mathrm{DLS} = \frac{100}{\mathrm{L}[(\sin \mathrm{I1} \times \sin \mathrm{I2})(\sin \mathrm{A1} \times \sin \mathrm{A2} + \cos \mathrm{A1} \times \cos \mathrm{A2}) + \cos \mathrm{I1} \times \cos \mathrm{I2}]} \tag{5.79}$$

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

$$\text{Dogleg severity} = \frac{100}{31[(\sin 13.5 \times \sin 14.7)(\sin 10 \times \sin 19) + (\cos 10 \times \cos 19) + (\cos 13.5 \times \cos 14.7)]}$$

$$\mathrm{DLS} = \frac{100}{30.969}$$

$$\mathrm{DLS} = 3.229 \text{ degrees/100 ft}$$

5.9.4 Available Weight on the 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:

$$\mathrm{P} = \mathrm{W} \times \cos \mathrm{I} \tag{5.80}$$

where: P = partial weight available for the bit
cos = cosine
I = degrees inclination (angle)
W = total weight of collars

Example: W = 45,000 lb
I = 25 degrees
P = 45,000 × cos25
P = 45,000 × 0.9063
P = 40,784 lb

Thus, the available weight on the bit is 40,784 lb.

5.9.5 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:

$$TVD_2 = \cos I \times CL + TVD_1 \tag{5.81}$$

where: TVD2 = new true vertical depth, ft
cos = cosine
CL = course length – number of feet since last survey
TVD1 = last true vertical depth, ft

Example: TVD(last survey) = 8500 ft
Devation angle = 40 degrees
Course length = 30 ft

Solution: $TVD_2 = \cos 40 \times 30\text{ ft} + 8500\text{ ft}$
$TVD_2 = 0.766 \times 30\text{ ft} + 8500\text{ ft}$
$TVD_2 = 22.98\text{ ft} + 8500\text{ ft}$
$TVD_2 = 8522.98\text{ ft}$

5.10 Miscellaneous Equations and Calculations

5.10.1 Surface Equipment Pressure Losses

$$\text{SEpl} = \text{C} \times \text{MW} \times \left(\frac{\text{Q}}{100}\right)^{1.86} \tag{5.82}$$

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

$$\text{SEpl} = 0.22 \times 11.8 \times \left(\frac{350}{100}\right)^{1.86}$$
$$\text{SEpl} = 2.596 \times (3.5)^{1.86}$$
$$\text{SEpl} = 2.596 \times 10.279372$$
$$\text{SEpl} = 26.69 \text{ psi}$$

5.10.2 Drill Stem Bore Pressure Losses

$$\text{P} = \frac{0.000061 \times \text{MW} \times \text{L} \times \text{Q}^{1.86}}{\text{d}^{4.86}} \tag{5.83}$$

where: P = drill stem bore pressure losses, psi
MW = mud weight, 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.

$$P = \frac{0.000061 \times 10.9 \times 6500 \times (350)^{1.86}}{4.276^{4.86}}$$

$$P = \frac{4.32185 \times 53,946.909}{1166.3884}$$

$$P = 199.89 \text{ psi}$$

5.10.3 Annular Pressure Losses

$$P = \frac{\left(1.4327 \times 10^{-7}\right) \times MW \times L \times V^2}{Dh - Dp} \tag{5.84}$$

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:

$$P = \frac{\left(1.4327 \times 10^{-7}\right) \times 12.5 \times 6500 \times 181^2}{8.5 - 5.0}$$

$$P = \frac{381.36}{3.5}$$

$$P = 108.96 \text{ psi}$$

5.10.4 Pressure Loss through Common Pipe Fittings

$$P = \frac{K \times MW \times Q^2}{12{,}031 \times A^2} \tag{5.85}$$

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.

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:
$$\begin{aligned}
K &= 0.90 \text{ for 90 degree ELL}\\
MW &= 8.33 \text{ ppg (water)}\\
Q &= 100 \text{ gpm}\\
A &= 12.5664 \text{ sq. in. (4.0 in. ID pipe)}\\
P &= \frac{0.90 \times 8.33 \times 100^2}{12{,}031 \times 12.5664^2}\\
P &= \frac{74{,}970}{1{,}899{,}868.3}\\
P &= 0.03946 \text{ psi}
\end{aligned}$$

5.10.5 Minimum Flow Rate for PDC Bits

$$\text{Minimum flowrate, gpm} = 12.72 \times \text{bit diameter, in.}^{1.47} \tag{5.86}$$

Example: Determine the minimum flow rate for a 12¼ in. PDC bit:

$$\begin{aligned}
\text{Minimum flowrate, gpm} &= 12.72 \times 12.25^{1.47}\\
\text{Minimum flowrate, gpm} &= 12.72 \times 39.77\\
\text{Minimum flowrate} &= 505.87 \text{ gpm}
\end{aligned}$$

5.10.6 Critical RPM: RPM to Avoid Due to Excessive Vibration (Accurate to Approximately 15%)

$$\text{Critical RPM} = \frac{33{,}055}{\text{L, ft}^2} \times \sqrt{\text{OD, in.}^2 + \text{ID, in.}^2} \tag{5.87}$$

Example:
$$\begin{aligned}
L &= \text{length of one joint of drill pipe} = 31 \text{ ft}\\
OD &= \text{drill pipe outside diameter} = 5.0 \text{ in.}\\
ID &= \text{drill pipe inside diameter} = 4.276 \text{ in.}
\end{aligned}$$

$$\text{Critical RPM} = \frac{33{,}055}{31^2} \times \sqrt{5.0^2 + 4.276^6}$$

$$\text{Critical RPM} = \frac{33{,}055}{961} \times \sqrt{43.284}$$

$$\text{Critical RPM} = 34.3965 \times 6.579$$

$$\text{Critical RPM} = 226.296$$

NOTE: As a rule of thumb, for 5.0 in. drill pipe, do not exceed 200 RPM at any depth.

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CHAPTER SIX

AIR AND GAS CALCULATIONS

Note 1: This chapter has unit system consistent equations, not field equations. The equations may be worked using either the USCS or SI. If USCS is used, pressure is (lb/ft^2 abs), specific weight (lb/ft^3) or specific gravity, temperature (°Rankin), and depth (ft). If SI is used, pressure is (N/m^2 abs), specific weight (N/m^3) or specific gravity, temperature (Kelvin), and depth (m). API Standard Conditions are 14.696 psia (~14.7 psia), 59 °F, and 0% humidity.

Note 2: Flow problems with gas require that the calculations be carried out from a flow state that is known (usually at the exit). This requires that the calculations proceed from that known position in the flow to subsequent upstream positions until the injection pressure and temperature are determined.

1. Static gas column

$$P_{bh} = P_{wh}\, e^{\frac{\left(\frac{S_g}{R}\right)H}{T_{av}}} \tag{6.1}$$

Where: P_{bh} = bottomhole pressure (lb/ft^2 abs)
P_{wh} = wellhead pressure at surface (lb/ft^2 abs)
H = TVD of the well (ft)
S_g = specific gravity of the gas
R = engineering gas constant at API standard conditions (53.36 ft-lb/lb-°R)

Example: Determine the approximate bottomhole shut-in pressure of a well filled with natural gas with an Sg = 0.7 and a TVD = 10,000 ft. The wellhead pressure is reading 1800 psig, and the average temperature in the well is determined to be 139 °F. The wellhead surface location is approximately sea level.

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$$p_{wh} = 1800 + 14.7 = 1814.7 \text{ psia}$$

$$P_{wh} = 1814.7\,(144) = 261{,}317 \text{ lb/ft}^2\text{abs}$$

$$T_{av} = 139^\circ + 460^\circ = 599\,^\circ\text{R}$$

$$P_{bh} = (261{,}317)e^{\frac{\left(\frac{0.7}{53.36}\right)(10{,}000)}{(599)}} = (261{,}317)(1.244) = 325{,}078 \text{ lb/ft}^2\text{abs}$$

$$p_{bh} = \frac{325{,}078}{144} = 2258 \text{ psia}$$

or

$$p_{bh} = 2258 - 14.7 = 2243 \text{ psig}$$

2. **Direct circulation—flow up the annulus (from annulus bottomhole to exit):** Unlike incompressible hydraulic flow calculations, compressible gas flow calculations must begin with a known pressure and temperature. This is usually at the exit to the system (top of annulus). In this case, the exit conditions are known, since the flow exits the annulus into the atmosphere at the surface. In essence, the calculation will proceed from the exit, then upstream to the bottom of the annulus. The bottomhole pressure in the annulus is

$$P_{bh} = \left[\left(P_{ex}^2 + b_a T_{av}^2\right) e^{\frac{2a_a H}{T_{av}}} b_a T_{av}^2\right] \tag{6.2}$$

Where: P_{ex} = exit pressure at the top of the annulus at the surface (lb/ft^2 abs) and

$$a_a = \left(\frac{S_g}{\mathbf{R}}\right)\left[1 + \left(\frac{\dot{w}_s}{\dot{w}_g}\right)\right]$$

$$b_a = \frac{f_a}{2g(D_h - D_p)}\left(\frac{\mathbf{R}}{S_g}\right)^2 \frac{\dot{w}_g^2}{\left(\frac{\pi}{4}\right)^2\left(D_h^2 - D_p^2\right)^2}$$

$$f_a = \left[\frac{1}{2\log_{10}\left(\frac{D_h - D_p}{\epsilon}\right) + 1.14}\right]^2$$

ε = 0.0005 ft (absolute roughness of inside of casing and outside of pipe)

$g = 32.2\ \text{ft/sec}^2$

D_h = inside diameter of annulus (ft)

D_p = pipe outside diameter (ft)

$\dot{w}_g = \gamma_g Q_g$

Where: Q_g = gas flow rate (ft^3/sec)

$$\gamma_g = \frac{P_g S_g}{\mathbf{R} T_g}$$

$$\dot{w}_s = \left(\frac{\pi}{4}\right) D_h^2 (62.4)(2.7)\left(\frac{\text{ROP}}{3600}\right)$$

Example: Determine the approximate bottomhole annulus pressure in a well being drilled with a 6⅛ in. drill bit on a drill string made of API 5.0 in., 19.50 lb/ft nominal weight (i.d. = 4.276 in.) drill string run inside an API 7⅝ in. casing, 39.00 lb/ft nominal weight (i.d. = 6.625 in.). The well is being drilled at an ROP of 60 ft/hr, and the drill fluid is inert air with a volumetric flow of 2000 SCFM that is produced by the nitrogen generator (S_g = 0.97). The well is vertical with a depth of 10,000 ft, and the surface location is near sea level at midlatitudes in North America. The geothermal gradient at this drilling location is approximately 0.016° per ft.

$t_{ex} = t_{at}$ (use average temperature)
$t_{ex} = 59\ ^\circ\text{F}$ (API standard temperature)
$t_{bh} = 59^\circ + 0.016^\circ(10{,}000)$
$t._{bh} = 219\ ^\circ\text{F}$

$$t_{av} = \left(\frac{59^\circ + 219^\circ}{2}\right) = 139\ ^\circ\text{F}$$

$T_{av} = 139^\circ + 460^\circ = 599\ ^\circ\text{R}$
$p_{ex} = p_{at}$
$p_{ex} = 14.7$ psia (API standard pressure)

$$P_{ex} = 14.7(144) = 2116.8 \text{ lb/ft}^2 \text{ abs}$$
$$t_{ex} = t_{at}$$
$$t_{ex} = 59\ ^\circ F$$
$$T_{ex} = 59^\circ + 460^\circ = 519\ ^\circ R$$
$$\gamma_g = \frac{(2116.8)(0.97)}{(53.36)(519)} = 0.0741 \text{ lb/ft}^3$$
$$q_g = 2000 \text{ SCFM}$$
$$Q_g = \frac{q_g}{60} = \frac{2000}{60} = 33.3 \text{ ft}^3/\text{sec}$$
$$\dot{w}_g = (0.0741)(33.3) = 2.471 \text{ lb/sec}$$
$$\dot{w}_s = \left(\frac{\pi}{4}\right)\left(\frac{6.125}{12}\right)^2 (62.4)(2.7)\left(\frac{60}{3600}\right) = 0.575 \text{ lb/sec}$$
$$a_a = \left(\frac{0.97}{53.36}\right)\left[1 + \left(\frac{0.575}{2.471}\right)\right] = 0.0224$$
$$D_c = \frac{6.625}{12} = 0.552 \text{ ft}$$
$$D_p = \frac{5.0}{12} = 0.417 \text{ ft}$$
$$f_a = \left[\frac{1}{2\log_{10}\left(\frac{0.552 - 0.417}{0.0005}\right) + 1.14}\right]^2 = 0.0278$$
$$b_a = \frac{0.0278}{2(32.2)(0.552 - 0.417)}\left(\frac{53.36}{0.97}\right)^2 \frac{(2.471)^2}{\left(\frac{\pi}{4}\right)^2\left[(0.552)^2 - (0.417)^2\right]^2}$$
$$= 5{,}532.9$$
$$P_{abh} = \left[(2116.8)^2 - (5{,}532.9)(599)^2 e^{\frac{2(0.0224)10{,}000}{599}} - (5{,}532.9)(599)^2\right]^{0.5}$$
$$P_{abh} = 47{,}106.3 \text{ lb/ft}^2 \text{abs}$$
$$p_{abh} = \left(\frac{47{,}106.3}{144}\right) = 327.1 \text{ psia}$$

or

$$p_{abh} = 312.4 \text{ psig}$$

3. **Direct circulation—flow down the inside of the drill pipe** (from the bottom of the inside of the drill string to the injection at the top of the drill string): In nearly all air and gas drilling operations, the drill bit nozzles are not jetted. Therefore, there is little or no pressure loss through the drill bit open orifices, and it can be assumed that the pressure and temperature at the bottom of the annulus will be approximately the same as the pressure and temperature at the bottom of the inside of the drill pipe just above the drill bit. The injection pressure into the inside of the drill string is

$$P_{in} = \left[\frac{P_{ai}^2 + b_i T_{av}^2 \left(e^{\frac{2a_i H}{T_{av}}} - 1 \right)}{e^{\frac{2a_i H}{T_{av}}}} \right]^{0.5} \tag{6.3}$$

Where: P_{ai} = pressure above the drill bit inside the drill string at the bottom of the well (lb/ft^2 abs) and

$$a_i = \left(\frac{S_g}{\mathbf{R}} \right)$$

$$b_i = \frac{f_i}{2gD_i} \left(\frac{\mathbf{R}}{S_g} \right)^2 \frac{\dot{w}_g^2}{\left(\frac{\pi}{4} \right)^2 D_i^4}$$

$$f_i = \left[\frac{1}{2 \log_{10} \left(\frac{D_i}{\varepsilon} \right) + 1.14} \right]^2$$

ε = 0.0005 ft (absolute roughness of inside the drill pipe)
g = 32.2 ft/sec^2
D_i = inside drill pipe diameter (ft)

Example: For the previous example, determine the approximate pressure of the nitrogen generator–produced inert air injected into the top of the inside of the drill string (the inside diameter of the drill string is 4.276 in.).

$$p_{abi} = 327.1 \text{ psia}$$

or

$$P_{abi} = 327.1(144) = 47{,}106.3 \text{ lb/ft}^2\text{abs}$$

$$a_i = \left(\frac{0.97}{53.36}\right) = 0.0182$$

$$D_i = \frac{4.276}{12} = 0.356 \text{ ft}$$

$$f_i = \left[\frac{1}{2\log_{10}\left(\frac{0.356}{0.0005}\right) + 1.14}\right]^2 = 0.0213$$

$$b_i = \frac{0.0213}{2(32.2)(0.356)}\left(\frac{53.36}{0.97}\right)^2 \frac{(2.471)^2}{\left(\frac{\pi}{4}\right)^2 (0.356)^4} = 1{,}727.2$$

$$P_{in} = \left[\frac{(47{,}106.3)^2 + (1{,}712.8)(599)^2\left(e^{\frac{2(0.0182)(10{,}000)}{599}} - 1\right)}{e^{\frac{2(0.0182)(10{,}000)}{599}}}\right]^{0.5}$$

$$P_{in} = 38{,}617.9 \text{ lb/ft}^2\text{abs}$$

$$p_{in} = \left(\frac{38{,}617.9}{144}\right) = 268.2 \text{ psia}$$

or

$$p_{in} = 253.5 \text{ psig}$$

4. **Reverse circulation—flow up the inside of tubing string:** Reverse circulation is often used in gas and condensate well workover operations. In such operations it is necessary to flow nitrogen-generated inert air down the annulus between the inside of the casing and the outside of the production tubing and up through the inside of the production tubing. In this manner, the pressure at the bottom of the well is reduced, which in turn allows the natural gas or condensate to flow from the formation and intermix with the injected inert air and proceed up the tubing to the surface. As the flow from the formation increases, the inert air flow can be reduced as the formation begins to flow naturally through the production tubing and the tubing head choke. The flow from the bottom of the inside of the tubing to the surface is

$$P_{bt} = \left[\left(P_{th}^2 + b_{it} T_{av}^2 \right) e^{\frac{2\,a_{it} H}{T_{av}}} b_{it}\, T_{av}^2 \right] \tag{6.4}$$

Where: P_{bt} = pressure above the drill bit inside the drill string at the bottom of the tubing (lb/ft^2 abs) and

$$a_{ti} = \left(\frac{S_g}{\mathbf{R}} \right)$$

$$b_{ti} = \frac{f_i}{2g\, D_{ti}} \left(\frac{\mathbf{R}}{S_g} \right)^2 \frac{\dot{w}_{tg}^2}{\left(\frac{\pi}{4} \right)^2 D_{ti}^4}$$

$$\dot{w}_{tg} = \dot{w}_{g1} + \dot{w}_{g2}$$

$$f_{ti} = \left[\frac{1}{2 \log_{10} \left(\frac{D_{ti}}{\varepsilon} \right) + 1.14} \right]^2$$

ε = 0.0005 ft (absolute roughness of inside the drill pipe)

g = 32.2 ft/sec^2

D_{ti} = inside tubing diameter (ft)

Example: Determine the approximate inside bottom pressure at the bottom of the tubing string. The production tubing string is API 2⅞ in., 6.50 lb/ft nominal weight (i.d. = 2.441 in.), and is hung in a 10,000 ft vertical well inside API 7⅝ in. casing, 39.00 lb/ft nominal weight (i.d. = 6.625 in.). A flow of 500 SCFM nitrogen-generated inert air ($S_g = 0.97$) is injected into the top of the annulus between the inside of the casing and the outside of the tubing. The flow continues to the bottom of the annulus and then flows up the inside of the tubing to the tubing head and to the choke at the surface. The tubing head pressure is to be kept at a constant 100 psig via the choke as the natural gas production is initiated with the reverse circulation operation. The temperature at the wellhead during circulation is estimated to be the surface ambient (standard API) temperature (59 °F). The natural gas ($S_g = 0.7$) producing formation has the potential to flow at a rate of up to 700 SCFM (or 1,008,000 SCFD). This illustrative example will show the calculations for a 200 SCFM of natural gas production rate. The geothermal gradient at this drilling location is approximately 0.016° per ft. The well is located at sea level at midlatitudes in North America.

$q_{g1} = 500$ SCFM (inert air)

$q_{g2} = 200$ SCFM (natural gas)

$S_{g1} = 0.97$

$S_{g2} = 0.7$

$p_{at} = 14.7$ psia

$p_{th} = 100$ psig

$P_{th} = 100 + 14.7 = 114.7$ psia

$P_{th} = 114.7(144) = 16{,}516.8 \text{ lb/ft}^2$ abs

$T_{th} = t_{at}$ (use average atmospheric temperature)

$t_{bh} = t_{at} + 0.016°(10{,}000)$

$t_{bh} = 219\ °F$

$$t_{av} = \left(\frac{59° + 219°}{2}\right) = 139\ °F$$

$T_{av} = 139° + 460° = 599\ °R$

$T_{API} = 59° + 460° = 519\ °R$

$$\gamma_{g1} = \frac{(2116.8)(0.97)}{(53.36)(519)} = 0.0741\ \text{lb/ft}^3$$

$$q_{g1} = 500\ \text{SCFM}$$

$$Q_{g1} = \frac{q_{g1}}{60} = \frac{500}{60} = 8.33\ \text{ft}^3/\text{sec}$$

$$\dot{w}_{g1} = (0.0741)(8.33) = 0.618\ \text{lb/sec}$$

$$\gamma_{g2} = \frac{(2116.8)(0.7)}{(53.36)(519)} = 0.0535\ \text{lb/ft}^3$$

$$Q_{g2} = \frac{q_{g2}}{60} = \frac{200}{60} = 3.33\ \text{ft}^3/\text{sec}$$

$$\dot{w}_{g2} = (0.0535)(3.33) = 0.178\ \text{lb/sec}$$

$$\dot{w}_{tg} = 0.618 + 0.178 = 0.796\ \text{lb/sec}$$

$$a_{ti} = \left(\frac{0.97}{53.36}\right) = 0.0182$$

$$d_{ti} = 2.441\ \text{in.}$$

$$D_{ti} = \frac{2.441}{12} = 0.203\ \text{ft}$$

$$f_{ti} = \left[\frac{1}{2\log_{10}\left(\frac{0.203}{0.0005}\right) + 1.14}\right]^2 = 0.0247$$

$$b_{ti} = \frac{0.0247}{2(32.2)(0.203)}\left(\frac{53.36}{0.97}\right)^2 \frac{(0.796)^2}{\left(\frac{\pi}{4}\right)^2 (0.203)^4} = 3{,}427.3$$

$$P_{bt} = \left[(16{,}516.8)^2 - (3{,}427.3)(599)^2 e^{\frac{2(0.0182)10{,}000}{599}} - (3{,}427.3)(599)^2\right]^{0.5}$$

$$P_{bt} = 39{,}078.5\ \text{lb/ft}^2\ \text{abs}$$

$$p_{bt} = \left(\frac{39{,}078.5}{144}\right) = 271.4\ \text{psia}$$

or

$$p_{bt} = 271.4 - 14.7 = 256.7\ \text{psig}$$

5. **Reverse circulation—flow down the annulus:** The pressure at the bottom of the tubing is known and is approximately the pressure at the bottomhole pressure in the annulus. In essence, the calculation will proceed from the bottom of the annulus upstream to determine the injection pressure at the top of the annulus. The injection pressure at the top of the annulus is

$$P_{in} = \left[\frac{P_{ba}^2 + b_a T_{av}^2\left(e^{\frac{2a_aH}{T_{av}}} - 1\right)}{e^{\frac{2a_aH}{T_{av}}}}\right]^{0.5} \tag{6.5}$$

Where: P_{ba} = pressure at bottom of annulus (lb/ft^2 abs) and

$$a_a = \left(\frac{S_g}{\mathbf{R}}\right)$$

$$b_a = \frac{f_a}{2g(D_c - D_{to})}\left(\frac{\mathbf{R}}{S_g}\right)^2 \frac{\dot{w}_{g1}^2}{\left(\frac{\pi}{4}\right)^2 \left(D_c^2 - D_{to}^2\right)^2}$$

$$f_a = \left[\frac{1}{2\log_{10}\left(\frac{D_c - D_{to}}{\varepsilon}\right) + 1.14}\right]^2$$

ε = 0.0005 ft (absolute roughness of inside of casing and outside of pipe)
g = 32.2 ft/sec^2
D_c = inside diameter of annulus casing (ft)
D_{to} = tubing outside diameter (ft)
$\dot{w}_{g1} = \gamma_{g1} Q_{g1}$

Where: Q_g = gas flow rate (ft^3/sec)

$$\gamma_g = \frac{P_g S_g}{\mathbf{R} T_g}$$

Example: Using the data from the above example, determine the approximate annulus injection pressure into the well that has been worked over and is being put back into production.

$$d_{to} = 2.875 \text{ in.}$$

$$D_{to} = \frac{2.875}{12} = 0.240 \text{ ft}$$

$$D_c = \frac{6.625}{12} = 0552 \text{ ft}$$

$$t_{in} = t_{at}$$

$$t_{in} = 59 \,^\circ\mathrm{F}$$

$$T_{ex} = 59^\circ + 460^\circ = 519 \,^\circ\mathrm{R}$$

$$\gamma_{g1} = \frac{(2116.8)(0.97)}{(53.36)(519)} = 0.0741 \text{ lb/ft}^3$$

$$Q_{g1} = \frac{500}{60} = 8.33 \text{ ft}^3/\text{sec}$$

$$\dot{w}_{g1} = (0.0741)(8.33) = 0.618 \text{ lb/sec}$$

$$a_a = \left(\frac{0.97}{53.36}\right) = 0.0182$$

$$f_a = \left[\frac{1}{2\log_{10}\left(\dfrac{0.552 - 0.240}{0.0005}\right) + 1.14}\right]^2 = 0.0221$$

$$b_a = \frac{0.0221}{2(32.2)(0.552 - 0.240)}\left(\frac{53.36}{0.97}\right)^2 \frac{(0.618)^2}{\left(\dfrac{\pi}{4}\right)^2\left[(0.552)^2 - (0.240)^2\right]^2}$$

$$= 547.9$$

$$P_{in} = \left[\frac{(39,078.5)^2 + (547.9)(599)^2\left(e^{\frac{2(0.0182)(10,000)}{599}} - 1\right)}{e^{\frac{2(0.0182)(10,000)}{599}}}\right]^{0.5}$$

$$P_{in} = 30,360.2 \text{ lb/ft}^2 \text{ abs}$$

$$p_{in} = \left(\frac{30,360.2}{144}\right) = 210.8 \text{ psia}$$

or

$$p_{in} = 210.8 - 14.7 = 196.1 \text{ psig}$$

Table 6-1 gives the results of the above calculations for a natural gas flow of 0 SCFM, 100 SCFM, and 200 SCFM.

Table 6-1
Natural Gas Flow versus Injection Pressure

q_{ng} (SCFM)	p_{in} (psig)
0	168.9
100	182.1
200	196.1

6. **Reverse circulation—adjusting for reservoir pressure:** If the inert air is injected into the top of a well annulus that is under pressure from the reservoir, then the compressor (and nitrogen generator) system will have to overcome the static pressure at the top of the annulus in order to initiate flow.

   Example: Let us assume that the static annulus pressure is given by the example in number 1 above. Figure 6-1 shows an example Inflow Performance Relationship (IPR) of the static well given in number 1. With no flow from the reservoir ($q_{ng} = 0$), the compressor system would have to inject inert air at

$$p_{inr} = 168.9 + 1800.0 = 1968.9 \text{ psig}$$

where the injection pressure is taken from Table 6-1.

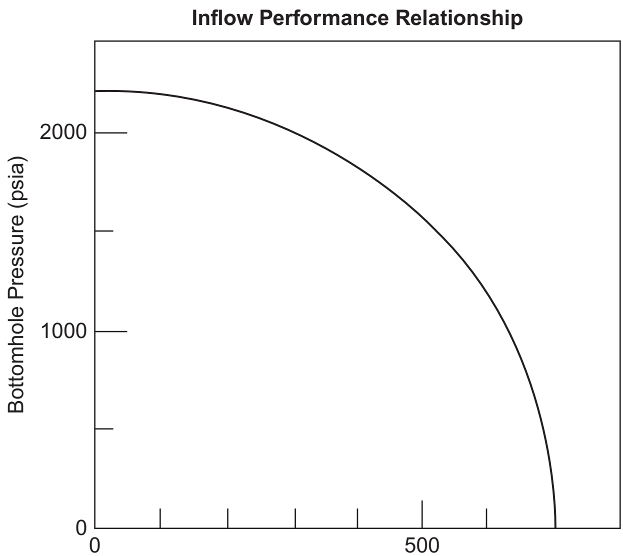

Figure 6-1. IPR for example well.

Table 6-2 gives the approximate bottomhole pressures and tubing head pressures for the natural gas flow rates given in Table 6-1. From Figure 6-1 the flowing reservoir pressure and its associated tubing head pressure can be estimated.

Table 6-2 shows that the inert air compressor injection pressures will decrease as the natural gas begins to flow up the production tubing to the surface as the well is brought into production. These injection pressures will require a 1000 SCFM primary compressor (either helical screw type or reciprocating piston) and nitrogen generator filter

Table 6-2
Approximate Compressor Injection Pressures

q_{ng} (SCFM)	p_{res} (psia)	p_{th} (psia)	p_{th} (psig)	p_{com} (psig)
0	2258	1814.7	1800.0	1968.9
100	2240	1800.7	1786.0	1968.1
200	2150	1728.3	1713.6	1909.7

unit and a booster compressor (which must be a reciprocating piston). The nitrogen generator "rule of thumb" is that only about 50% of the primary compressed air will be available after the 1000 SCFM of compressed air flows through the nitrogen generator filter unit. This leaves just 500 SCFM to be injected by the booster compressor into the well.

APPENDIX A

Table A-l
Drill Pipe Capacity and Displacement (English System)

Size OD in.	Size ID in.	Weight lb/ft	Capacity bbl/ft	Displacement bbl/ft
2⅜	1.815	6.65	0.00320	0.00228
2⅞	2.150	10.40	0.00449	0.00354
3½	2.764	13.30	0.00742	0.00448
3½	2.602	15.50	0.00658	0.00532
4	3.340	14.00	0.01084	0.00471
4½	3.826	16.60	0.01422	0.00545
4½	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
5½	4.778	21.90	0.02218	0.00721
5½	4.670	24.70	0.02119	0.00820
5⁹⁄₁₆	4.859	22.20	0.02294	0.00712
6⅝	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
3½	2.0625	25.3	0.00421	0.00921
4	2.25625	29.7	0.00645	0.01082
4½	2.75	41.0	0.00743	0.01493
5	3.0	49.3	0.00883	0.01796

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Additional capacities, bbl/ft, displacements, bbl/ft, and weight, lb/ft can be determined from the following:

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

$$\text{Displacement, bbl/ft} = \frac{\left(\text{Dh, in.}^2 - \text{Dp, in.}^2\right)}{1029.4}$$

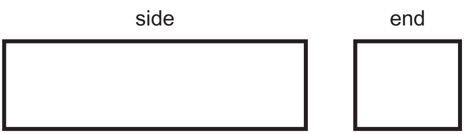
$$\text{Weight, lb/ft} = \text{displacement, bbl/ft} \times 2747\ \text{lb/bbl}$$

Table A-3
Drill Pipe Capacity and Displacement (Metric System)

Size OD in.	Size ID in.	Weight lb/ft	Capacity l/ft	Displacement l/ft
$2\frac{3}{8}$	1.815	6.65	1.67	1.19
$2\frac{7}{8}$	2.150	10.40	2.34	1.85
$3\frac{1}{2}$	2.764	13.30	3.87	2.34
$3\frac{1}{2}$	2.602	15.50	3.43	2.78
4	3.340	14.00	5.65	2.45
$4\frac{1}{2}$	3.826	16.60	7.42	2.84
$4\frac{1}{2}$	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
$5\frac{1}{2}$	4.778	21.90	11.57	3.76
$5\frac{1}{2}$	4.670	24.70	11.05	4.28
$5\frac{9}{16}$	4.859	22.20	11.96	3.72
$6\frac{5}{8}$	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 a flat bottom using the following data:

Length = 30 ft
Width = 10 ft
Depth = 8 ft

$$\text{Volume, bbl} = \frac{30\text{ ft} \times 10\text{ ft} \times 8\text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{2400}{5.61}$$

$$\text{Volume} = 427.84\text{ bbl}$$

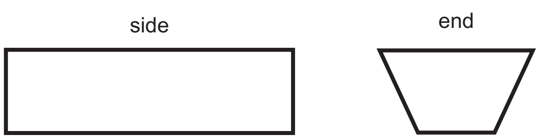
Example 2: Determine the capacity of this same tank with only 5½ ft of fluid in it:

$$\text{Volume, bbl} = \frac{30\text{ ft} \times 10\text{ ft} \times 5.5\text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{1650}{5.61}$$

$$\text{Volume} = 294.12\text{ bbl}$$

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 (top) = 10 ft
Width (bottom) = 6 ft
Depth = 8 ft

Table A-4
Drill Collar Capacity and Displacement

O.D.	I.D. Capacity	1½ in. .0022	1¾ in. .0030	2 in. .0039	2¼ in. .0049	2½ in. .0061	2¾ in. .0073	3 in. .0087	3¼ in. .0103	3½ in. .0119	3¾ in. .0137	4 in. .0155	4¼ in. .0175
4 in.	#/ft	36.7	34.5	32.0	29.2	_	_	_	_	_	_	_	_
	Disp.	.0133	.0125	.0116	.0106								
4¼ in.	#/ft	42.2	40.0	37.5	34.7	_	_	_	_	_	_	_	_
	Disp.	.0153	.0145	.0136	.0126								
4½ in.	#/ft	48.1	45.9	43.4	40.6	_	_	_	_	_	_	_	_
	Disp.	.0175	.0167	.0158	.0148								
4¾ in.	#/ft	54.3	52.1	49.5	46.8	43.6	_	_	_	_	_	_	_
	Disp.	.0197	.0189	.0180	.0170	.0159							
5 in.	#/ft	60.8	58.6	56.3	53.3	50.1	_	_	_	_	_	_	_
	Disp.	.0221	.0213	.0214	.0194	.0182							
5¼ in.	#/ft	67.6	65.4	62.9	60.1	56.9	53.4	_	_	_	_	_	_
	Disp.	.0246	.0238	.0229	.0219	.0207	.0194						
5½ in.	#/ft	74.8	72.6	70.5	67.3	64.1	60.6	56.8	_	_	_	_	_
	Disp.	.0272	.0264	.0255	.0245	.0233	.0221	.0207					
5¾ in.	#/ft	82.3	80.1	77.6	74.8	71.6	68.1	64.3	_	_	_	_	_
	Disp.	.0299	.0291	.0282	.0272	.0261	.2048	.0234					
6 in.	#/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	67.9	.0247	.0231			
6¼ in.	#/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			

6½ in.	#/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			
6¾ in.	#/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 in.	#/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	
7¼ in.	#/ft	134.	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	
7½ in.	#/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	
7¾ in.	#/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 in.	#/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	.0573	.0561	.0549	.0535	.0520	.0503	.0485	.0467	.0447
8¼ in.	#/ft	176.0	173.8	171.3	168.3	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
8½ in.	#/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	.0672	.0663	.0653	.0641	.0629	.0615	.0600	.0583	.0565	.0547	.0527
8¾ in.	#/ft	199.0	196.8	194.3	191.5	188.3	184.8	181.0	176.8	172.3	167.4	162.3	156.8
	Disp.	.0724	.0716	.0707	.0697	.0685	.0672	.0658	.0613	.0697	.0609	.0590	.0570
9 in.	#/ft	210.2	208.0	205.6	202.7	199.6	196.0	192.2	188.0	183.5	178.7	173.5	168.0
	Disp.	.0765	.0757	.0748	.0738	.0726	.0714	.0700	.0685	.0668	.0651	.0632	.0612
10 in.	#/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	.0084	.0869	.0853	.0835	.0816	.0796

$$\text{Volume, bbl} = \frac{30\text{ ft }[8\text{ ft }(10\text{ ft} + 6\text{ ft})]}{5.62}$$

$$\text{Volume, bbl} = \frac{30\text{ ft} \times 128}{5.62}$$

$$\text{Volume} = 683.3\text{ bbl}$$

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

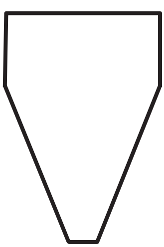
NOTE: The radius (r) is one-half of the diameter:

$$\text{Volume, bbl} = \frac{3.14 \times 5\text{ ft}^2 \times 15\text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{1177.5}{5.61}$$

$$\text{Volume} = 209.89\text{ bbl}$$

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:

$$Vt = 0.059 \times 3.14 \times h_t \times \left(r_c^{\,2} + r_b^{\,2} + r_b r_c\right)$$

Where: Vc = 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:

$$Vc = 0.1781 \times 3.14 \times 6.0^2 \times 5.0$$
$$Vc = 100.66 \text{ bbl}$$

b) Volume of tapered section:

$$V_t = 0.059 \times 3.14 \times 10 \text{ ft} \times \left(6^2 + 1^2 + 1 \times 6\right)$$
$$V_t = 1.8526\ (36 + 1 + 6)$$
$$V_t = 1.8526 \times 43$$
$$V_t = 79.66 \text{ bbl}$$

c) Total volume:

$$\text{bbl} = 100.66 \text{ bbl} + 79.66 \text{ bbl}$$
$$\text{bbl} = 180.32$$

Horizontal Cylindrical Tank

a) Total tank capacity:

$$\text{Volume, bbl} = \frac{3.14 \times r^2 \times L(7.48)}{42}$$

b) Partial volume:

$$\text{Volume, ft}^3 = L\left[0.017453 \times r^2 \times \cos^{-1}\left(\frac{r-h}{r}\right) - \sqrt{2hr - h^2} \times (r-h)\right]$$

Example 1: Determine the total volume of the following tank:

Length = 30 ft
Radius = 4 ft

a) Total tank capacity:

$$\text{Volume, bbl} = \frac{3.14 \times 4^2 \times 30 \times 7.48}{42}$$

$$\text{Volume, bbl} = \frac{11{,}279.574}{42}$$

$$\text{Volume} = 268.56 \text{ bbl}$$

Example 2: Determine the volume if there are only 2 feet of fluid in this tank: (h = 2 ft)

$$\text{Volume, ft}^3 = 30\left[0.017453 \times 4^2 \times \cos^{-1}\left(\frac{4-2}{4}\right) - \sqrt{2 \times 2 \times 4 - 2^2} \times (4-2)\right]$$

$$\text{Volume, ft}^3 = 30\left[0.0279248 \times \cos^{-1}(0.5) - \sqrt{12} \times (4-2)\right]$$

$$\text{Volume, ft}^3 = 30\,(0.279248 \times 60 - 3.464 \times 2)$$

$$\text{Volume, ft}^3 = 30 \times 9.827$$

$$\text{Volume} = 294 \text{ ft}^3$$

To convert volume, ft^3, to barrels, multiply by 0.1781.
To convert volume, ft^3, to gallons, multiply by 7.4805.

Therefore, 2 ft of fluid in this tank would result in:

$$\text{Volume, bbl} = 294 \text{ ft}^3 \times 0.1781$$

$$\text{Volume} = 52.36 \text{ bbl}$$

NOTE: This is only applicable until the tank is half full (r – h). After that, calculate the 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/mm	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}

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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/ft^3	7.48
Pounds/gallon	Specific gravity	0.120
Pounds/gallon	Grams/cm^3	0.1198
Grams/cm^3	Pounds/gallon	8.347
Pounds/ft^3	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

Pressure

Atmospheres	Pounds/sq. in.	14.696
Atmospheres	Kilograms/sq. cm.	1.033
Atmospheres	Pascals	1.033×10^5
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.	Kilograms/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	3.51×10^{-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 feet	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

Appendix C
Average Annual Atmospheric Conditions

This appendix gives the graphic representation of the average atmospheric conditions for midlatitudes (30º N to 60º N) of the North American continent. Figure C-1 gives the average annual atmospheric pressure of air for midlatitudes of the North American continent as a function of surface elevation location above mean sea level. These average annual atmospheric pressures are of critical importance in predicting the actual weight rate of flow of air (or other gases) at an actual drilling location. Figure C-1a is given in USCS units, and Figure C-1b is given in SI units.

Figure C-2 gives the average annual atmospheric temperature of air for midlatitudes of the North American continent as a function of surface elevation location above mean sea level. These average annual atmospheric temperatures are of critical importance in predicting the approximate geothermal temperature at an actual drilling location. Figure C-2a is given in USCS units, and Figure C-2b is given in SI units.

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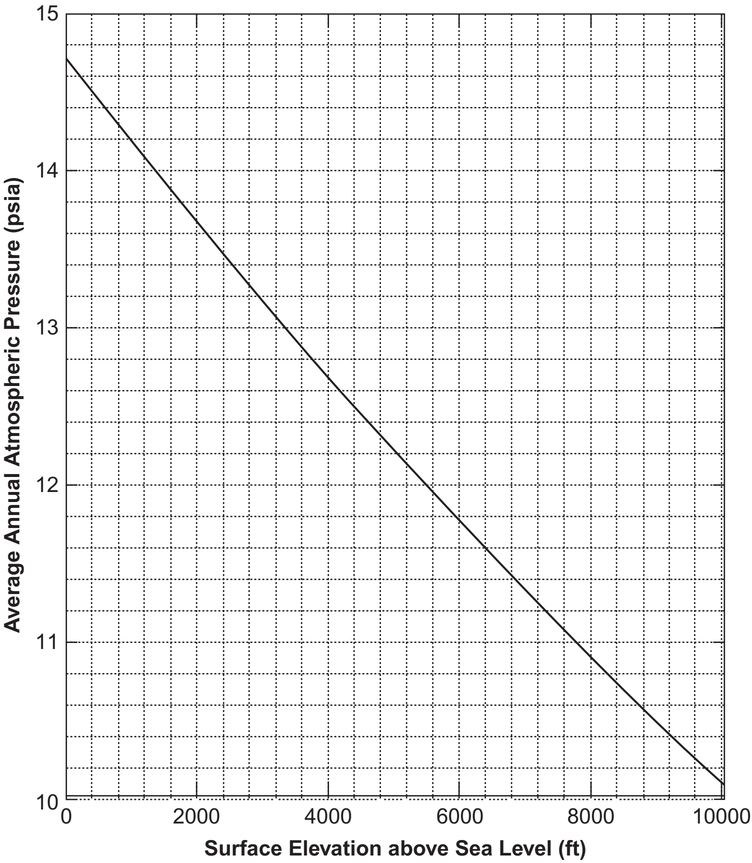

Figure C-1a. Average annual atmospheric pressure versus surface elevation above mean sea level (USCS units).

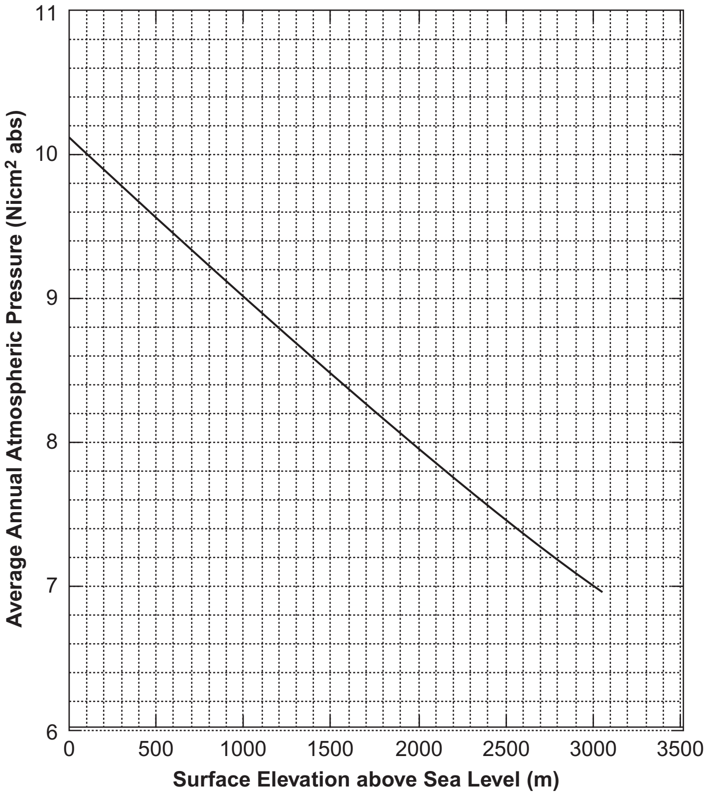

Figure C-1b. Average annual atmospheric pressure versus surface elevation above mean sea level (SI units).

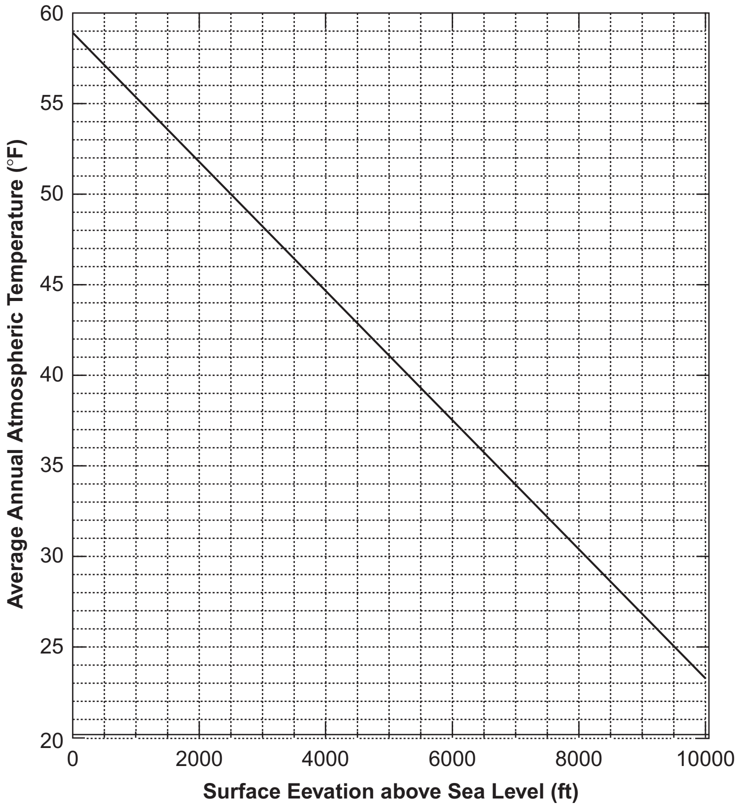

Figure C-2a. Average annual atmospheric temperature versus surface elevation above sea level (USCS units).

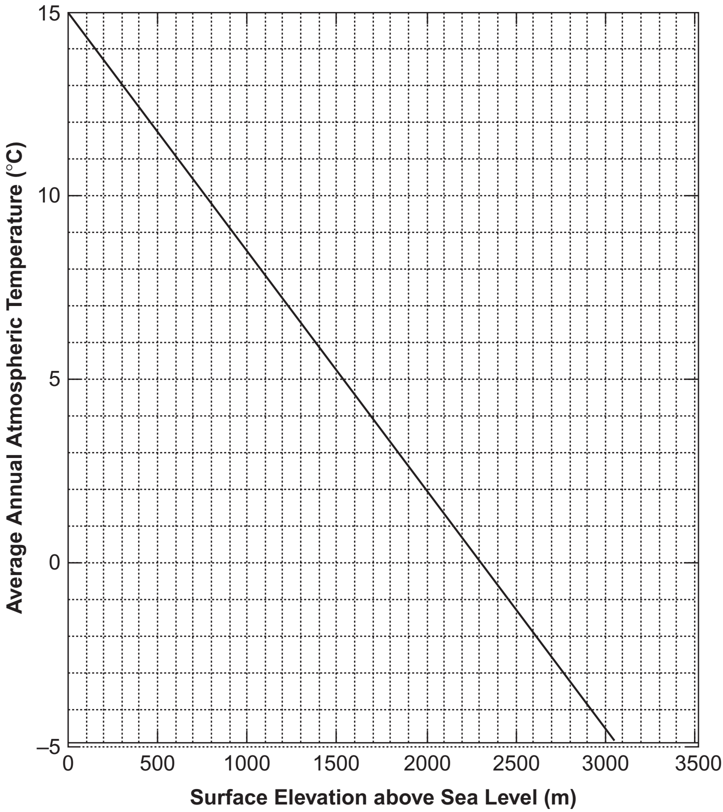

Figure C-2b. Average annual atmospheric temperature versus surface elevation above sea level (SI units).

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Note: Page numbers followed by *f* indicate figures and *t* indicate tables.

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