Formulas and Calculations for Drilling, Production and Work-over

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CHAPTER ONE

BASIC FORMULAS
1. **Pressure Gradient**

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

\[
\text{psi/ft} = \text{mud weight, ppg} \times 0.052 \\
\text{Example:} \ 12.0 \text{ ppg fluid}
\]

\[
\text{psi/ft} = 12.0 \text{ ppg} \times 0.052 \\
\text{psi/ft} = 0.624
\]

**Pressure gradient, psi/ft, using mud weight, lb/ft}^3\)**

\[
\text{psi/ft} = \text{mud weight, lb/ft}^3 \times 0.006944 \\
\text{Example:} \ 100 \text{ lb/ft}^3 \text{ fluid}
\]

\[
\text{psi/ft} = 100 \text{ lb/ft}^3 \times 0.006944 \\
\text{psi/ft} = 0.6944
\]

OR

\[
\text{psi/ft} = \text{mud weight, lb/ft}^3 \div 144 \\
\text{Example:} \ 100 \text{ lb/ft}^3 \text{ fluid}
\]

\[
\text{psi/ft} = 100 \text{ lb/ft}^3 \div 144 \\
\text{psi/ft} = 0.6944
\]

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

\[
\text{psi/ft} = \text{mud weight, SG} \times 0.433 \\
\text{Example:} \ 1.0 \text{ SG fluid}
\]

\[
\text{psi/ft} = 1.0 \text{ SG} \times 0.433 \\
\text{psi/ft} = 0.433
\]

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

\[
\text{ppg} = \text{pressure gradient, psi/ft} \div 0.052 \\
\text{Example:} \ 0.4992 \text{ psi/ft}
\]

\[
\text{ppg} = 0.4992 \text{ psi/ft} \div 0.052 \\
\text{ppg} = 9.6
\]

**Convert pressure gradient, psi/ft, to mud weight, lb/ft}^3\)**

\[
\text{lb/ft}^3 = \text{pressure gradient, psi/ft} \div 0.006944 \\
\text{Example:} \ 0.6944 \text{ psi/ft}
\]

\[
\text{lb/ft}^3 = 0.6944 \text{ psi/ft} \div 0.006944 \\
\text{lb/ft}^3 = 100
\]

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

\[
\text{SG} = \text{pressure gradient, psi/ft} \times 0.433 \\
\text{Example:} \ 0.433 \text{ psi/ft}
\]

\[
\text{SG} 0.433 \text { psi/ft} \div 0.433 \\
\text{SG} = 1.0
\]
2. **Hydrostatic Pressure (HP)**

**Hydrostatic pressure using ppg and feet as the units of measure**

\[ HP = \text{mud weight, ppg} \times 0.052 \times \text{true vertical depth (TVD), ft} \]

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

\[ HP = 13.5 \text{ ppg} \times 0.052 \times 12,000 \text{ ft} \]

\[ HP = 8424 \text{ psi} \]

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

\[ HP = \frac{\text{psi/ft}}{\text{true vertical depth, ft}} \]

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

\[ HP = 0.624 \text{ psi/ft} \times 8500 \text{ ft} \]

\[ HP = 5304 \text{ psi} \]

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

\[ HP = \frac{\text{mud weight, lb/ft}^3}{0.006944} \times \text{true vertical depth, ft} \]

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

\[ HP = 90 \text{ lb/ft}^3 \times 0.006944 \times 7500 \text{ ft} \]

\[ HP = 4687 \text{ psi} \]

**Hydrostatic pressure, psi, using meters as unit of depth**

\[ HP = \text{mud weight, ppg} \times 0.052 \times \text{TVD, m} \times 3.281 \]

*Example:* Mud weight = 12.2 ppg  
true vertical depth = 3700 meters

\[ HP = 12.2 \text{ ppg} \times 0.052 \times 3700 \times 3.281 \]

\[ HP = 7,701 \text{ psi} \]

3. **Converting Pressure into Mud Weight**

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

\[ \text{mud weight, ppg} = \frac{\text{pressure, psi}}{0.052 + \text{TVD, ft}} \]

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

\[ \text{mud} = \frac{2600 \text{ psi}}{0.052} \div 5000 \text{ ft} \]

\[ \text{mud} = 10.0 \text{ ppg} \]
Convert pressure, psi, into mud weight, ppg using meters as the unit of measure

mud weight, ppg = pressure, psi ÷ 0.052 ÷ TVD, m + 3.281

*Example:* pressure = 3583 psi  
true vertical depth = 2000 meters  
mud wt, ppg = 3583 psi ÷ 0.052 ÷ 2000 m ÷ 3.281  
mud wt = 10.5 ppg

4. **Specific Gravity (SG)**

**Specific gravity using mud weight, ppg**

\[ \text{SG} = \text{mud weight, ppg} + 8.33 \]

*Example:* 15.0 ppg fluid

SG = 15.0 ppg ÷ 8.33  
SG = 1.8

**Specific gravity using pressure gradient, psi/ft**

\[ \text{SG} = \text{pressure gradient, psi/ft} \times 0.433 \]

*Example:* pressure gradient = 0.624 psi/ft

SG = 0.624 psi/ft ÷ 0.433  
SG = 1.44

**Specific gravity using mud weight, lb/ft}^3**

\[ \text{SG} = \text{mud weight, lb/ft}^3 \div 62.4 \]

*Example:* Mud weight = 120 lb/ft}^3

SG = 120 lb/ft}^3 ÷ 62.4  
SG = 1.92

**Convert specific gravity to mud weight, ppg**

mud weight, ppg = specific gravity x 8.33  

*Example:* specific gravity = 1.80

mud wt, ppg = 1.80 x 8.33  
mud wt = 15.0 ppg

**Convert specific gravity to pressure gradient, psi/ft**

\[ \text{psi/ft} = \text{specific gravity} \times 0.433 \]

*Example:* specific gravity = 1.44

psi/ft = 1.44 x 0.433  
psi/ft = 0.624
Convert specific gravity to mud weight, lb/ft$^3$

\[ \text{lb/ft}^3 = \text{specific gravity} \times 62.4 \]

Example: specific gravity $= 1.92$

\[ \text{lb/ft}^3 = 1.92 \times 62.4 \]

\[ \text{lb/ft}^3 = 120 \]

5. Equivalent Circulating Density (ECD), ppg

\[ \text{ECD, ppg} = \frac{\text{annular pressure, loss, psi}}{0.052} \div \frac{\text{TVD, ft}}{+ \text{mud weight, in use, ppg}} \]

Example: annular pressure loss $= 200$ psi true vertical depth $= 10,000$ ft

\[ \text{ECD, ppg} = 200 \text{ psi} \div 0.052 \div 10,000 \text{ ft} + 9.6 \text{ ppg} \]

\[ \text{ECD} = 10.0 \text{ ppg} \]

6. Maximum Allowable Mud Weight from Leak-off Test Data

\[ \text{ppg} = \frac{\text{Leak-off Pressure, psi}}{0.052} \div \frac{\text{(Casing Shoe TVD, ft)}}{+ \text{(mud weight, ppg)}} \]

Example: leak-off test pressure $= 1140$ psi casing shoe TVD $= 4000$ ft

\[ \text{ppg} = 1140 \text{ psi} \div 0.052 \div 4000 \text{ ft} + 10.0 \text{ ppg} \text{ ppg} = 15.48 \]

7. Pump Output (P0)

Triplex Pump Formula 1

\[ \text{PO, bbl/stk} = 0.000243 \times (\text{liner diameter, in.})^2 \times (\text{stroke length, in.}) \]

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

\[ \text{PO @ 100%} = 0.000243 \times 72 \times 12 \]

\[ \text{PO @ 100%} = 0.142884 \text{ bbl/stk} \]

Adjust the pump output for 95% efficiency: Decimal equivalent $= 95 \div 100 = 0.95$

\[ \text{PO @ 95%} = 0.142884 \text{ bbl/stk} \times 0.95 \]

\[ \text{PO @ 95%} = 0.13574 \text{ bbl/stk} \]

---

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**Formula 2**

PO, gpm = \[3 (7^2 \times 0.7854) \times S \times 0.00411 \times SPM\]

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

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

PO, gpm = \[3 (72 \times 0.7854) \times 12 \times 0.00411 \times 80\]

PO, gpm = 1385.4456 \times 0.00411 \times 80

PO = 455.5 gpm

**Duplex Pump   Formula 1**

\[0.000324 \times (\text{Liner Diameter, in.})^2 \times (\text{stroke length, in.}) = \text{_________ bbl/stk}\]
\[-0.000162 \times (\text{Liner Diameter, in.})^2 \times (\text{stroke length, in.}) = \text{_________ bbl/stk}\]

Pump output @ 100% eff = \text{_________ bbl/stk}

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

\[0.000324 \times 5.5^2 \times 14 = 0.137214 \text{ bbl/stk}\]
\[-0.000162 \times 2.0^2 \times 14 = 0.009072 \text{ bbl/stk}\]

Pump output 100% eff = 0.128142 bbl/stk

Adjust pump output for 85% efficiency:

Decimal equivalent = \(85 \div 100 = 0.85\)

PO @ 85% = 0.128142 bbl/stk \times 0.85

PO @ 85% = 0.10892 bbl/stk

**Formula 2**

PO, bbl/stk = \[0.000162 \times S \times [2(D)^2 - d^2]\]

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

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

PO @ 100% = 0.000162 \times 14 \times [2 (5.5)^2 - 2^2]

PO @ 100% = 0.000162 \times 14 \times 56.5

PO @ 100% = 0.128142 bbl/stk

Adjust pump output for 85% efficiency:

PO @ 85% = 0.128142 bbl/stk \times 0.85

PO @ 85% = 0.10892 bbl/stk
8. **Annular Velocity (AV)**

**Annular velocity (AV), ft/min**

**Formula 1**

\[ AV = \frac{\text{pump output, bbl/min}}{\text{annular capacity, bbl/ft}} \]

*Example:* pump output = 12.6 bbl/min annular capacity = 0.126 bbl/ft

\[ AV = \frac{12.6 \text{ bbl/min}}{0.1261 \text{ bbl/ft}} \]

\[ AV = 99.92 \text{ ft/mm} \]

**Formula 2**

\[ AV, \text{ ft/mm} = \frac{24.5 \times Q}{Dh^2 - Dp^2} \]

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

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

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

\[ AV = \frac{12,985}{129.8125} \]

\[ AV = 100 \text{ ft/mm} \]

**Formula 3**

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

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

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

\[ AV = \frac{12970.44}{129.8125} \]

\[ AV = 99.92 \text{ ft/mm} \]

**Annular velocity (AV), ft/sec**

\[ AV, \text{ ft/sec} = \frac{17.16 \times PO, \text{ bbl/min}}{Dh^2 - Dp^2} \]
Example: pump output = 12.6 bbl/min  hole size = 12-1/4 in.  pipe OD = 4-1/2 in.

\[
AV = \frac{17.16 \times 12.6 \text{ bbl/min}}{12.25^2 - 45^2}
\]

\[
AV = 216.216
\]

\[
AV = 129.8125
\]

\[
AV = 1.6656 \text{ ft/sec}
\]

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

Pump output, gpm = \( \frac{AV, \text{ ft/mm} \times \left(Dh^2 - Dp^2\right)}{24.5} \)

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/mm  hole size = 12-1/4 in  
pipe OD = 4-1/2 in.

\[
PO = 120 \times \frac{(12.25^2 - 45^2)}{24.5}
\]

\[
PO = 120 \times 129.8125
\]

\[
PO = 15577.5
\]

\[
PO = 635.8 \text{ gpm}
\]

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

\[
SPM = \frac{\text{annular velocity, ft/mm} \times \text{annular capacity, bbl/ft}}{\text{pump output, bbl/stk}}
\]

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

\[
SPM = \frac{120 \times 0.1261}{0.136}
\]

\[
SPM = 15.132
\]

\[
SPM = 111.3
\]
9. Capacity Formulas

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

a) Annular capacity, bbl/ft = \( \frac{D_h^2 - D_p^2}{1029.4} \)

**Example:** Hole size (\(D_h\)) = 12-1/4 in. Drill pipe OD (\(D_p\)) = 5.0 in.

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

Annular capacity = 0.12149 bbl/ft

b) Annular capacity, ft/bbl = \( \frac{1029.4}{(D_h^2 - D_p^2)} \)

**Example:** Hole size (\(D_h\)) = 12-1/4 in. Drill pipe OD (\(D_p\)) = 5.0 in.

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

Annular capacity = 8.23 ft/bbl

c) Annular capacity, gal/ft = \( \frac{D_h^2 - D_p^2}{24.51} \)

**Example:** Hole size (\(D_h\)) = 12-1/4 in. Drill pipe OD (\(D_p\)) = 5.0 in.

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

Annular capacity = 5.1 gal/ft

d) Annular capacity, ft/gal = \( \frac{24.51}{(D_h^2 - D_p^2)} \)

**Example:** Hole size (\(D_h\)) = 12-1/4 in. Drill pipe OD (\(D_p\)) = 5.0 in.

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

Annular capacity, ft/gal = 0.19598 ft/gal
e) Annular capacity, ft³/linft = \(\frac{D_h^2 - D_p^2}{183.35}\)

Example: Hole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = 5.0 in.
Annular capacity, ft³/linft = \(\frac{12.25^2 - 5.0^2}{183.35}\)
Annular capacity = 0.682097 ft³/linft

f) Annular capacity, linft/ft³ = \(\frac{183.35}{(D_h^2 - D_p^2)}\)

Example: Hole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = 5.0 in.
Annular capacity, linft/ft³ = \(\frac{183.35}{12.25^2 - 5.0^2}\)
Annular capacity = 1.466 linft/ft³

**Annular capacity between casing and multiple strings of tubing**

a) Annular capacity between casing and multiple strings of tubing, bbl/ft:
Annular capacity, bbl/ft = \(\frac{D_h^2 - [(T_1)^2 + (T_2)^2]}{1029.4}\)

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 — 2-3/8 in. OD = 2.375 in.
T₂ = tubing No. 2 — 2-3/8 in. OD = 2.375 in.
Annular capacity, bbl/ft = \(\frac{6.1842 - (2.375^2 + 2.375^2)}{1029.4}\)
Annular capacity, bbl/ft = \(\frac{38.24 - 11.28}{1029.4}\)
Annular capacity = 0.02619 bbl/ft

b) Annular capacity between casing and multiple strings of tubing, ft/bbl:
Annular capacity, ft/bbl = \(\frac{1029.4}{D_h^2 - [(T_1)^2 + (T_2)^2]}\)

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 — 2-3/8 in. OD = 2.375 in.
T₂ = tubing No. 2 — 2-3/8 in. OD = 2.375 in.
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:

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

**Example:** Using two tubing strings of different size:

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

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

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

\[ \text{Annular capacity} = 0.8302733 \text{ gal/ft} \]

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

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

**Example:** Using two tubing strings of different sizes:

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

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

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

\[ \text{Annular capacity} = 1.2044226 \text{ ft/gal} \]

e) Annular capacity between casing and multiple strings of tubing, ft^3/linft:

\[ \text{Annular capacity, ft}^3/\text{linft} = \frac{Dh^2 - [(T_1)^2 + (T_2)^2 + (T_3)^2]}{183.35} \]
**Example:** Using three strings of tubing:

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

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

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

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

f) **Annular capacity between casing and multiple strings of tubing, linft/ft}^3:**

\[ \text{Annular capacity, linft/ft}^3 = \frac{183.35}{\text{Dh}^2 - [(T_1)^2 + (T_2)^2 + (T_3)^2]} \]

**Example:** Using three strings tubing of same size:

- **Dh** = casing 9-5/8 in. 47 lb/ft  ID = 8.681 in.
- **T**₁ = tubing No. 1 3-1/2 in.  OD = 3.5 in.
- **T**₂ = tubing No. 2 3-1/2 in.  OD = 3.5 in.
- **T**₃ = tubing No. 3 3-1/2 in.  OD = 3.5 in.

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

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

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

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

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

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

\[ \text{Capacity, bbl/ft} = \frac{12 \times 2.5^2}{1029.4} \]

\[ \text{Capacity} = 0.1457766 \text{ bbl/ft} \]

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

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

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

\[ \text{Capacity} = 6.8598 \text{ ft/bbl} \]
c) Capacity, gal/ft = \( \frac{ID\text{ in.}^2}{24.51} \)

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

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

\[
\text{Capacity} = 2.9477764 \text{ gal/ft}
\]

d) Capacity, ft/gal ID in 2

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

\[
\text{Capacity, ft/gal} = \frac{2451}{8.5^2}
\]

\[
\text{Capacity} = 0.3392 \text{ ft/gal}
\]

e) Capacity, \( \text{ft}^3/\text{linft} = \frac{ID^2}{18135} \)

Example: Determine the capacity, \( \text{ft}^3/\text{linft} \), for a 6.0 in. hole:

\[
\text{Capacity, } \frac{\text{ft}^3}{\text{linft}} = \frac{6.0^2}{183.35}
\]

\[
\text{Capacity} = 0.1963 \text{ ft}^3/\text{linft}
\]

f) Capacity, \( \text{linftft}^3 = \frac{183.35}{ID, \text{ in.}^2} \)

Example: Determine the capacity, \( \text{linft}/\text{ft}^3 \), for a 6.0 in. hole:

\[
\text{Capacity, unit/ft}^3 = \frac{183.35}{6.0^2}
\]

\[
\text{Capacity} = 5.09305 \text{ linft/ft}^3
\]

**Amount of cuttings drilled per foot of hole drilled**

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

\[
\text{Barrels} = \frac{Dh^2}{1029.4} \left(1 - \% \text{ porosity}\right)
\]

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

\[
\text{Barrels} = \frac{12.25^2}{1029.4} \left(1 - 0.20\right)
\]

\[
\text{Barrels} = 0.1457766 \times 0.80
\]

\[
\text{Barrels} = 0.1166213
\]

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

\[
\text{Cubic feet} = \frac{Dh^2 \times 0.7854}{144} \left(1 - \% \text{ porosity}\right)
\]


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

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

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

c) Total solids generated:

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

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

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

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

\[
W_{cg} = 9797.26 \text{ pounds}
\]

10. Control Drilling

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

\[
MDR, \text{ ft/hr} = 67 \times \frac{(\text{mud wt out, ppg} - \text{mud wt in, ppg}) \times (\text{circulation rate, gpm})}{\text{Dh}^2}
\]

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 = 17-1/2 in.

\[
MDR, \text{ ft/hr} = \frac{67 \times (9.7 — 9.0) \times 530}{17.5^2}
\]

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

\[
MDR, \text{ ft/hr} = 24.857 \]

\[
\text{MDR} = 81.16 \text{ ft/hr}
\]
11. **Buoyancy Factor (BF)**

**Buoyancy factor using mud weight, ppg**

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

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

\[
BF = \frac{65.5 - 15.0}{65.5}
\]

\[
BF = 0.77099
\]

**Buoyancy factor using mud weight, lb/ft³**

\[
BF = \frac{489 - \text{mud weight, lb/ft³}}{489}
\]

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

\[
BF = \frac{489 - 120}{489}
\]

\[
BF = 0.7546
\]

12. **Hydrostatic Pressure (HP) Decrease When POOH**

**When pulling DRY pipe**

**Step 1**

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

**Step 2**

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

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

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

Step 1
Barrels displaced = 5 stands x 92 ft/std x 0.0075 bbl/ft displaced
Barrels displaced = 3.45

Step 2
HP, psi decrease = \(\frac{3.45 \text{ barrels}}{0.0773 \text{ bbl/ft} - 0.0075 \text{ bbl/ft}}\) x 0.052 x 11.5 ppg

HP, psi decrease = \(\frac{3.45 \text{ barrels}}{0.0698}\) x 0.052 x 11.5 ppg

HP decrease = 29.56 psi

When pulling WET pipe

Step 1
Barrels displaced = number of stands pulled X average length per stand ft X (pipe disp., bbl/ft + pipe cap., bbl/ft)

Step 2
HP, psi = \(\frac{\text{barrels displaced}}{\text{casing capacity} - (\text{Pipe disp., + pipe cap.})}\) x 0.052 x mud weight, ppg

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
Mud weight = 11.5 ppg
Pipe displacement = 0.0075 bbl/ft
Pipe capacity = 0.01776 bbl/ft
Casing capacity = 0.0773 bbl/ft

Step 1
Barrels displaced = 5 stands x 92 ft/std x (0.0075 bbl/ft + 0.01776 bbl/ft)
Barrels displaced = 11.6196

Step 2
HP, psi decrease = \(\frac{11.6196 \text{ barrels}}{0.0773 \text{ bbl/ft} - (0.0075 \text{ bbl/ft + 0.01776 bbl/ft})}\) x 0.052 x 11.5 ppg

HP, psi decrease = \(\frac{11.6196}{0.05204}\) x 0.052 x 11.5 ppg

HP decrease = 133.52 psi
13. **Loss of Overbalance Due to Falling Mud Level**

**Feet of pipe pulled DRY to lose overbalance**

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

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

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

\[
\text{Ft} = 150 \text{ psi} \times (0.0773 — 0.0075) \times 11.5 \text{ ppg x 0.052 x 0.0075} \\
\text{Ft} = 10.47 \\
\text{Ft} = 2334
\]

**Feet of pipe pulled WET to lose overbalance**

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

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

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

\[
\text{Ft} = 150 \text{ psi x } (0.0773 — 0.01776 — 0.0075 \text{ bbl/ft}) \times 11.5 \text{ ppg x 0.052 x (0.01776 + 0.0075 \text{ bbl/ft})} \\
\text{Ft} = 7.806 \\
\text{Ft} = 516.8
\]
14. **Formation Temperature (FT)**

\[ FT, ^\circ F = (\text{ambient surface temperature, } ^\circ F) + (\text{temp. increase } ^\circ F \text{ per ft of depth} \times \text{TVD, ft}) \]

*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:

\[ FT, ^\circ F = 70 ^\circ F + (0.012 ^\circ F/ft \times 15,000 \text{ ft}) \]
\[ FT, ^\circ F = 70 ^\circ F + 180 ^\circ F \]
\[ FT = 250 ^\circ F \text{ (estimated formation temperature)} \]

15. **Hydraulic Horsepower (HHP)**

\[ HHP = \frac{P \times Q}{714} \]

where \( HHP = \text{hydraulic horsepower} \quad P = \text{circulating pressure, psi} \quad Q = \text{circulating rate, gpm} \)

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

\[ HHP = \frac{2950 \times 520}{1714} \]
\[ HHP = 1,534,000 \]
\[ HHP = 894.98 \]

16. **Drill Pipe/Drill Collar Calculations**

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

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

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

Weight, lb/ft = displacement, bbl/ft x 2747 lb/bbl
Example: Determine the capacity, bbl/ft, displacement, bbl/ft, and weight, lb/ft, for the following:

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

Convert 13/16 to decimal equivalent: 13 ÷ 16 = 0.8125

a) Capacity, bbl/ft = $\frac{2.8125^2}{1029.4}$
   Capacity = 0.007684 bbl/ft

b) Displacement, bbl/ft = $\frac{8.0^2 - 2.8125^2}{1029.4}$
   Displacement, bbl/ft = 56.089844
   Displacement = 0.0544879 bbl/ft

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

Rule of thumb formulas

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

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

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

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

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

Example: Spiral drill collars

Drill collar OD = 8.0 in.
Drill collar ID = 2-13/16 in.
Decimal equivalent = 2.8 125 in.

Weight, lb/ft = $(8.0^2 - 2.8125^2) \times 2.56$
Weight, lb/ft = 56.089844 x 2.56
Weight = 143.59 lb/ft
17. **Pump Pressure/Pump Stroke Relationship**  
(Also Called the Roughneck’s Formula)

**Basic formula**

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

*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 |

New circulating pressure, psi = 1800 psi x \( \left( \frac{30 \text{ spm}}{60 \text{ spm}} \right)^2 \)  
New circulating pressure, psi = 1800 psi x 0.25  
New circulating pressure = 450 psi

**Determination of exact factor in above equation**

The above formula is an approximation because the factor \( \left( \frac{\text{new pump rate, spm}}{\text{old pump rate, spm}} \right)^2 \) is a rounded-off number. To determine the exact factor, obtain two pressure readings at different pump rates and use the following formula:

\[
\text{Factor} = \frac{\log (\text{pressure 1 ÷ pressure 2})}{\log (\text{pump rate 1 ÷ pump rate 2})}
\]

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

Factor = \( \frac{\log (2500 \text{ psi} ÷ 450 \text{ psi})}{\log (315 \text{ gpm} ÷ 120 \text{ gpm})} \)  
Factor = \( \frac{\log (5.5555556)}{\log (2.625)} \)  
Factor = 1.7768

*Example:* Same example as above but with correct factor:

New circulating pressure, psi = 1800 psi x \( \left( \frac{30 \text{ spm}}{60 \text{ spm}} \right)^{1.7768} \)  
New circulating pressure, psi = 1800 psi x 0.2918299  
New circulating pressure = 525 psi
18. **Cost Per Foot**

\[ C_T = \frac{B + CR(t + T)}{F} \]

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

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

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

\[ C_T = 66,400 \]

\[ 1300 \]

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

19. **Temperature Conversion Formulas**

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

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

*Example:* Convert 95 °F to °C:

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

\[ °C = 35 \quad °C = 35 \]

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

\[ °F = \frac{(°C \times 9)}{5} + 32 \quad \text{OR} \quad °F = 24 \times 1.8 + 32 \]

*Example:* Convert 24 °C to °F:

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

\[ °F = 75.2 \quad °F = 75.2 \]

**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 ÷ 2

*Example:* Convert 95 °F to °C

°C = 95 — 30 ÷ 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
1. Volumes and Strokes

Drill string volume, barrels

Barrels = ID, in.$^2$ x pipe length
\[ \frac{1029.4}{1} \]

Annular volume, barrels

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

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

Strokes = barrels ÷ pump output, bbl/stk

Example: Determine volumes and strokes for the following:

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

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

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

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

Hole size = 12-1/4 in.

Drill string volume

a) Drill pipe volume, bbl:  
Barrels = \( \frac{4.276^2 \times 9400}{1029.4} \)  
Barrels = 166.94

b) Drill collar volume, bbl:  
Barrels = \( \frac{3.0^2 \times 600}{1029.4} \)  
Barrels = 5.24

c) Total drill string volume:  
Total drill string vol., bbl = 166.94 bbl + 5.24 bbl  
Total drill string vol. = 172.18 bbl

Annular volume

a) Drill collar / open hole:  
Barrels = \( \frac{12.25^2 - 8.0^2 \times 600}{1029.4} \)  
Barrels = 50.16
Formulas and Calculations

b) Drill pipe / open hole: 
Barrels = \frac{12.25^2 - 5.0^2}{1029.4} \times 4900 \text{ ft} 
Barrels = 0.12149 \times 4900 \text{ ft} 
Barrels = 595.3 

c) Drill pipe / cased hole: 
Barrels = \frac{12.615^2 - 5.0^2}{1029.4} \times 4500 \text{ ft} 
Barrels = 0.130307 \times 4500 \text{ ft} 
Barrels = 586.38 

d) Total annular volume: 
Total annular vol. = 50.16 + 595.3 + 586.38 
Total annular vol. = 1231.84 \text{ barrels} 

Strokes

a) Surface to bit strokes: 
Strokes = \text{drill string volume, bbl} \div \text{pump output, bbl/stk} 
Surface to bit strokes = 172.16 \text{ bbl} \div 0.136 \text{ bbl/stk} 
Surface to bit strokes = 1266 

b) Bit to surface (or bottoms-up strokes): 
Strokes = \text{annular volume, bbl} \div \text{pump output, bbl/stk} 
Bit to surface strokes = 1231.84 \text{ bbl} \div 0.136 \text{ bbl/stk} 
Bit to surface strokes = 9058 

c) Total strokes required to pump from the Kelly to the shale shaker: 
Strokes = \text{drill string vol., bbl} + \text{annular vol., bbl} \div \text{pump output, bbl/stk} 
Total strokes = (172.16 + 1231.84) \div 0.136 
Total strokes = 1404 \div 0.136 
Total strokes = 10,324 

2. Slug Calculations

Barrels of slug required for a desired length of dry pipe

Step 1 Hydrostatic pressure required to give desired drop inside drill pipe: 

HP, psi = \text{mud wt, ppg} \times 0.052 \times \text{ft of dry pipe} 

Step 2 Difference in pressure gradient between slug weight and mud weight: 

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

Step 3 Length of slug in drill pipe: 

Slug length, ft = \text{pressure, psi} \div \text{difference in pressure gradient, psi/ft}
Step 4  Volume of slug, barrels:

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

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

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

Step 1  Hydrostatic pressure required:

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

HP = 117 psi

Step 2  Difference in pressure gradient, psi/ft:

psi/ft = (slug wt, ppg — mud wt, ppg) × 0.052

psi/ft = 0.052

Step 3  Length of slug in drill pipe, ft:

Slug length, ft = HP, psi × 0.052 ÷ slug length, ft

Slug length = 2250 ft

Step 4  Volume of slug, bbl:

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

Slug vol. = 32.0 bbl

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

Step 1  Length of slug in drill pipe, ft:

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

Step 2  Hydrostatic pressure required to give desired drop inside drill pipe:

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

Step 3  Weight of slug, ppg:

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

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

Desired length of dry pipe (2 stands) = 184 ft  
Mud weight = 12.2 ppg
Drill pipe capacity 4-1/2 in. — 16.6 lb/ft = 0.01422 bbl/ft  
Volume of slug = 25 bbl
Step 1 Length of slug in drill pipe, ft: Slug length, ft = 25 bbl ± 0.01422 bbl/ft Slug length = 1758 ft

Step 2 Hydrostatic pressure required: HP, Psi = 12.2 ppg x 0.052 x 184 ft HP, Psi = 117 psi

Step 3 Weight of slug, ppg: Slug wt, ppg = 117 psi ÷ 0.052 ÷ 1758 ft + 12.2 ppg Slug wt, ppg = 1.3 ppg + 12.2 ppg Slug wt = 13.5 ppg

Volume, height, and pressure gained because of slug:

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

Vol., bbl = ft of dry pipe x drill pipe capacity, bbl/ft

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

Height, ft = annulus vol., ft/bbl x slug vol., bbl

c) Hydrostatic pressure gained in annulus because of slug:

HP, psi = height of slug in annulus, ft X difference in gradient, psi/ft between slug wt and mud wt

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

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

Vol., bbl = 184 ft x 0.01422 bbl/ft Vol. = 2.62 bbl

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

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

c) Hydrostatic pressure gained in annulus because of slug:

HP, psi = 641.5 ft (13.2 — 12.2) x 0.052 HP, psi = 641.5 ft x 0.052 HP = 33.4 psi
3. Accumulator Capacity — Usable Volume Per Bottle

Usable Volume Per Bottle

NOTE: The following will be used as guidelines:

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

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

\[ P_1 V_1 = P_2 V_2 \]

Surface Application

Step 1 Determine hydraulic fluid necessary to increase pressure from pre-charge to minimum:

\[ P_1 V_1 = P_2 V_2 \]

1000 psi x 10 gal = 1200 psi x V

\[ \frac{10,000}{1200} = V_2 \]

\[ V_2 = 8.33 \] The nitrogen has been compressed from 10.0 gal to 8.33 gal.

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

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

Step 2 Determine hydraulic fluid necessary to increase pressure from pre-charge to maximum:

\[ P_1 V_1 = P_2 V_2 \]

1000 psi x 10 gals = 3000 psi x V

\[ \frac{10,000}{3000} = V_2 \]

\[ V_2 = 3.33 \] The nitrogen has been compressed from 10 gal to 3.33 gal.

10.0 — 3.33 = 6.67 gal of hydraulic fluid per bottle.

Step 3 Determine usable volume per bottle:

Useable vol./bottle = Total hydraulic fluid/bottle — Dead hydraulic fluid/bottle

Useable vol./bottle = 6.67 — 1.67

Useable vol./bottle = 5.0 gallons
Subsea Applications

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

*Example:* Same guidelines as in surface applications:

\[
\text{Water depth} = 1000 \text{ ft} \quad \text{Hydrostatic pressure of hydraulic fluid} = 445 \text{ psi}
\]

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

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

**Step 2** Determine hydraulic fluid necessary to increase pressure from pre-charge to minimum:

\[
P_1 V_1 = P_2 V_2 \quad \Rightarrow \quad 1445 \text{ psi} \times 10 = 1645 \times V_2
\]

\[
14,450 = V_2
\]

\[
\frac{14,450}{1645} = 8.78 \text{ gal}
\]

10.0 — 8.78 = 1.22 gal of dead hydraulic fluid

**Step 3** Determine hydraulic fluid necessary to increase pressure from pre-charge to maximum:

\[
1445 \text{ psi} \times 10 = 3445 \text{ psi} \times V_2
\]

\[
14450 = V_2
\]

\[
\frac{14450}{3445} = 4.19 \text{ gal}
\]

10.0 — 4.19 = 5.81 gal of hydraulic fluid per bottle.

**Step 4** Determine useable fluid volume per bottle:

\[
\text{Useable vol./bottle} = \frac{\text{Total hydraulic fluid/bottle} — \text{Dead hydraulic fluid/bottle}}{1.22}
\]

Useable vol./bottle = 5.81 — 1.22

Useable vol./bottle = 4.59 gallons

Accumulator Pre-charge Pressure

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

\[ P, \text{psi} = \text{vol. removed, bbl} \div \text{total acc. vol., bbl} \times \left( \frac{(P_f \times P_s)}{(P_s - P_f)} \right) \]

where \( P \) = average pre-charge pressure, psi  \( P_f \) = final accumulator pressure, psi  \( P_s \) = starting accumulator pressure, psi

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

- Starting accumulator pressure \( (P_s) = 3000 \text{ psi} \)
- Final accumulator pressure \( (P_f) = 2200 \text{ psi} \)
- Volume of fluid removed \( = 20 \text{ gal} \)
- Total accumulator volume \( = 180 \text{ gal} \)

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

\[
P, \text{psi} = 0.1111 \times 8250
\]

\[ P = 917 \text{ psi} \]

### 4. Bulk Density of Cuttings (Using Mud Balance)

**Procedure:**

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

The specific gravity of the cuttings is calculated as follows:

\[ SG = \frac{1}{2 \times (0.12 \times Rw)} \]

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

**Example:** \( Rw = 13.8 \text{ ppg} \). Determine the bulk density of cuttings:

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

\[ SG = \frac{1}{0.344}
\]

\[ SG = 2.91 \]
5. **Drill String Design (Limitations)**

The following will be determined:

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

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

1. **Length of bottom hole assembly necessary for a desired weight on bit:**

Length, ft = \( \frac{WOB \times f}{Wdc \times BF} \)

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

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

Solution:

a) Buoyancy factor (BF):

\[ BF = \frac{65.5 - 12.0 \text{ ppg}}{65.5} \]

\[ BF = 0.8168 \]

b) Length of bottom hole assembly (BHA) necessary:

\[ \text{Length, ft} = \frac{50000 \times 1.15}{147 \times 0.8168} \]

\[ \text{Length, ft} = \frac{57.500}{120.0696} \]

\[ \text{Length} = 479 \text{ ft} \]

2. **Feet of drill pipe that can be used with a specific BHA**

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

a) Determine buoyancy factor:

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

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

\[ \text{Length}_{\text{max}} = \frac{(T \times f) - \text{MOP} - \text{Wbha} \times BF}{Wdp} \]
where \( T \) = tensile strength, lb for new pipe
\( f \) = safety factor to correct new pipe to no. 2 pipe
MOP = margin of overpull
\( W_{bha} \) = BHA weight in air, lb/ft
\( W_{dp} \) = drill pipe weight in air, lb/ft. including tool joint
\( BF \) = buoyancy factor

c) Determine total depth that can be reached with a specific bottom-hole assembly:

Total depth, ft = \( \text{length}_{\text{max}} + \text{BHA length} \)

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

a) Buoyancy factor:
\[ BF = \frac{65.5 - 13.5}{65.5} \]
\[ BF = 0.7939 \]
b) Maximum length of drill pipe that can be run into the hole:
\[ \text{Length}_{\text{max}} = \left[ \frac{(554,000 \times 0.90) - 100,000 - 50,000}{21.87} \right] \times 0.7939 \]
\[ \text{Length}_{\text{max}} = \frac{276.754}{21.87} \]
\[ \text{Length}_{\text{max}} = 12,655 \text{ ft} \]
c) Total depth that can be reached with this BHA and this drill pipe:

Total depth, ft = 12,655 ft + 500 ft
Total depth = 13,155 ft

---

6. **Ton-Mile (TM) Calculations**

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

1. Round trip ton-miles
2. Drilling or “connection” ton-miles
3. Coring ton-miles
4. Ton-miles setting casing
5. Short-trip ton-miles
**Round trip ton-miles (RT\textsubscript{TM})**

\[
RT_{\text{TM}} = \frac{W_p \times D \times (L_p + D) \div (2 \times D) \times (2 \times W_b + W_c)}{5280 \times 2000}
\]

where  
- \(RT_{\text{TM}}\) = round trip ton-miles  
- \(W_p\) = buoyed weight of drill pipe, lb/ft  
- \(D\) = depth of hole, ft  
- \(L_p\) = length of one stand of drill pipe, (aye), ft  
- \(W_b\) = weight of travelling block assembly, lb  
- \(W_c\) = buoyed weight of drill collars in mud minus the buoyed weight of the same length of drill pipe, lb  
- \(2000\) = number of pounds in one ton  
- \(5280\) = number of feet in one mile

*Example:* Round trip ton-miles

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

Solution:  

a) Buoyancy factor: 

\[BF = 65.5 - 9.6 \text{ ppg.} \div 65.5\]

\[BF = 0.8534\]

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

\[W_p = 13.3 \text{ lb/ft} \times 0.8534\]

\[W_p = 11.35 \text{ lb/ft}\]

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

\[W_c = (300 \times 83 \times 0.8534) - (300 \times 13.3 \times 0.8534)\]

\[W_c = 21,250 - 3,405\]

\[W_c = 17,845 \text{ lb}\]

Round trip ton-miles \(= \) \(\frac{11.35 \times 4000 \times (60 + 4000) + (2 \times 4000) \times (2 \times 15000 + 17845)}{5280 \times 2000}\)

\[RT_{\text{TM}} = \frac{11.35 \times 4000 \times 4060 + 8000 \times (30000 + 17845)}{5280 \times 2000}\]

\[RT_{\text{TM}} = \frac{11.35 \times 4000 \times 4060 + 8000 \times 47845}{10,560,000}\]

\[RT_{\text{TM}} = \frac{1.8432 \text{ 08} + 3.8276 \text{ 08}}{10,560,000}\]

\[RT_{\text{TM}} = 53.7\]
Drilling or “connection” ton-miles

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

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

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

where

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

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

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

Ton-miles during coring operations

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

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

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

where

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

Ton-miles setting casing

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

$$T_c = \frac{W_p \times D \times (L_{cs} + D) + D \times W_b \times 0.5}{5280 \times 2000}$$

where

- $T_c$ = ton-miles setting casing
- $W_p$ = buoyed weight of casing, lb/ft
- $L_{cs}$ = length of one joint of casing, ft
- $W_b$ = weight of travelling block assembly, lb
Ton-miles while making short trip

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

\[ T_{st} = T_6 - T_5 \]

where 
- \( T_{st} \) = 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.

7. Cementing Calculations

Cement additive calculations

a) Weight of additive per sack of cement:

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

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

Water, gal/sk = Cement water requirement, gal/sk + Additive water requirement, gal/sk

c) Volume of slurry, gal/sk:

\[ \text{Vol gal/sk} = \frac{94 \text{ lb}}{\text{SG of cement} \times 8.33 \text{ lb/gal}} + \frac{\text{weight of additive, lb}}{\text{SG of additive} \times 8.33 \text{ lb/gal}} + \text{water volume, gal} \]

d) Slurry yield, ft\(^3\)/sk:

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

e) Slurry density, lb/gal:

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

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

Determine the following: 
- Amount of bentonite to add
- Total water requirements
- Slurry yield
- Slurry weight
1) Weight of additive:

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

2) Total water requirement:

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

3) Volume of slurry:

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

Vol. gallsk = 3.5938 + 0.1703 + 7.7
Vol.          = 11.46 gal/sk

4) Slurry yield, ft$^3$/sk:

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

5) Slurry density, lb/gal:

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

Density         = 14.13 lb/gal

Water requirements

a) Weight of materials, lb/sk:

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

b) Volume of slurry, gal/sk:

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

SG x 8.33

SG x 8.33

c) Water requirement using material balance equation:

D_1 V_1 = D_2 V_2

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

Determine the following:

Bentonite requirement, lb/sk  Water requirement, gallsk
Slurry yield, ft$^3$/sk    Check slurry weight, lb/gal
1) Weight of materials, lb/sk:

Weight, lb/sk = 94 + (0.06 x 94) + (8.33 x “y”)

Weight, lb/sk = 94 + 5.64 + 8.33 “y”

Weight = 99.64 + 8.33 “y”

2) Volume of slurry, gal/sk:

Vol, gal/sk = 94 + 5.64 + (8.33 x 3.14 x 8.33)

Vol, gal/sk = 3.6 + 0.26 + “y”

Vol, gal/sk = 3.86

3) Water requirements using material balance equation

99.64 + 8.33 “y” = (3.86 + “y”) x 14.0

99.64 + 8.33 “y” = 54.04 + 14.0 “y”

99.64 - 54.04 = 14.0 “y” - 8.33 “y”

45.6 = 5.67 “y”

8.0 = “y” Thus, water required = 8.0 gal/sk of cement

4) Slurry yield, ft³/sk:

Yield, ft³/sk = 3.6 + 0.26 + 8.0

Yield, ft³/sk = 11.86

Yield = 15.9 ft³/sk

5) Check slurry density, lb/gal:

Density, lb/gal = 94 + 5.64 + (8.33 x 8.0)

Density, lb/gal = 166.28

Density = 14.0 lb/gal

**Field cement additive calculations**

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

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

a) Volume of mixing water, gal:
   
   Volume = 240 sk x 8.6 gal/sk
   Volume = 2064 gal

b) Total weight, lb, of mixing water:
   
   Weight = 2064 gal x 8.33 lb/gal
   Weight = 17,193 lb

c) Bentonite requirement, Lb:
   
   Bentonite = 17,193 lb x 0.015%
   Bentonite = 257.89 lb

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

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

a) Weight of cement:
   
   Weight = 240 sk x 94 lb/sk
   Weight = 22,560 lb

b) Halad = 0.5%
   
   Halad = 22,560 lb x 0.005
   Halad = 112.8 lb

c) CFR-2 = 0.40%
   
   CFR-2 = 22,560 lb x 0.004
   CFR-2 = 90.24 lb

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

<table>
<thead>
<tr>
<th></th>
<th>Water Requirement gal/94 lb/sk</th>
<th>Specific Gravity</th>
</tr>
</thead>
<tbody>
<tr>
<td>API Class Cement</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class A &amp; B</td>
<td>5.2</td>
<td>3.14</td>
</tr>
<tr>
<td>Class C</td>
<td>6.3</td>
<td>3.14</td>
</tr>
<tr>
<td>Class D &amp; E</td>
<td>4.3</td>
<td>3.14</td>
</tr>
<tr>
<td>Class G</td>
<td>5.0</td>
<td>3.14</td>
</tr>
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<td>Class H</td>
<td>4.3 — 5.2</td>
<td>3.14</td>
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<td>Chem Comp Cement</td>
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<td>3.14</td>
</tr>
<tr>
<td>Attapulgite</td>
<td>1.3/2% in cement</td>
<td>2.89</td>
</tr>
<tr>
<td>Cement Fondu</td>
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<td>3.23</td>
</tr>
<tr>
<td>Common Cement Additives</td>
<td>Water Requirement gal/94 lb/sk</td>
<td>Specific Gravity</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>-------------------------------</td>
<td>-----------------</td>
</tr>
<tr>
<td>Lumnite Cement</td>
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<td>Trinity Lite-weight Cement</td>
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<td>Bentonite</td>
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<td>Diace D</td>
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<td>Diace LWL</td>
<td>0 (up to 0.7%) 0.8:1/1% in cement</td>
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<td>Gilsonite</td>
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<td>0 (up to 5%) 0.4-0.5 over 5%</td>
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<td>LA-2 Latex</td>
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<td>NF-D</td>
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<tr>
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<tr>
<td>Perlite 6</td>
<td>6/38 lb/ft³</td>
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<td>Pozmix A</td>
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<td>Sand Ottawa</td>
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<td>Silica flour</td>
<td>1.6/35% in cement</td>
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<tr>
<td>Coarse silica</td>
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<td>Spacer mix (liquid)</td>
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<tr>
<td>Tuf Plug</td>
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</tbody>
</table>
8. Weighted Cement Calculations

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

\[ x = \frac{Wt \times 11.207983 \div SGc + (wt \times CW) - 94 - (8.33 \times CW)}{(1 + (AW \div 100)) - (wt \div (SGa \times 8.33)) - (wt + (AW \div 100))} \]

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

<table>
<thead>
<tr>
<th>Additive</th>
<th>Water Requirement gal/94 lb/sk</th>
<th>Specific Gravity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hematite</td>
<td>0.34</td>
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<tr>
<td>Ilmenite</td>
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<tr>
<td>Barite</td>
<td>2.5</td>
<td>4.23</td>
</tr>
<tr>
<td>Sand</td>
<td>0</td>
<td>2.63</td>
</tr>
<tr>
<td>API Cements</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class A &amp; B</td>
<td>5.2</td>
<td>3.14</td>
</tr>
<tr>
<td>Class C</td>
<td>6.3</td>
<td>3.14</td>
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<td>Class D,E,F,H</td>
<td>4.3</td>
<td>3.14</td>
</tr>
<tr>
<td>Class G</td>
<td>5.2</td>
<td>3.14</td>
</tr>
</tbody>
</table>

Example: Determine how much hematite, lb/sk of cement, would be required to increase the density of Class H cement to 17.5 lb/gal:
- Water requirement of cement = 4.3 gal/sk
- Water requirement of additive (hematite) = 0.34 gal/sk
- Specific gravity of cement = 3.14
- Specific gravity of additive (hematite) = 5.02

Solution:

\[ x = \frac{(17.5 \times 11.207983 \div 3.14) + (17.5 \times 4.3) - 94 - (8.33 \times 4.3)}{(1 + (0.34 \div 100)) - (17.5 \div (5.02 \times 8.33)) - (17.5 \times (0.34 \div 100))} \]

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

\[ x = 7.8959 + 0.525406 \]

\[ x = 15.1 \text{ lb of hematite per sk of cement used} \]
9. Calculations for the Number of Sacks of Cement Required

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

**Step 1**: Determine the following capacities:

a) Annular capacity, ft³/ft:

\[
\text{Annular capacity, ft}^3/\text{ft} = \frac{D_h \text{ in.}^2 - D_p \text{ in.}^2}{183.35}
\]

b) Casing capacity, ft³/ft:

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

c) Casing capacity, bbl/ft:

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

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

\[
\text{Sacks required} = \frac{\text{feet to be cemented}}{\text{Annular capacity, ft}^3/\text{ft}} \times \text{excess yield, ft}^3/\text{sk LEAD cement}
\]

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

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

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

Total Sacks of TAIL cement required:

\[
\text{Sacks} = \text{sacks required in annulus} + \text{sacks required in casing}
\]

**Step 4** Determine the casing capacity down to the float collar:

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

**Step 5** Determine the number of strokes required to bump the plug:

\[
\text{Strokes} = \frac{\text{casing capacity, bbl}}{\text{pump output, bbl/blk}}
\]
Formulas and Calculations

Example: From the data listed below determine the following:

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

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

Cement program:  
- LEAD cement (13.8 lb/gal) = 2000 ft  slurry yield = 1.59 ft³/sk
- TAIL cement (15.8 lb/gal) = 1000 ft  slurry yield = 1.15 ft³/sk
- Excess volume = 50%

Step 1 Determine the following capacities:

a) Annular capacity, ft³/ft:

Annular capacity, ft³/ft = \( \frac{17.5^3 - 13.375^3}{183.35} \)

Annular capacity, ft³/ft = 127.35938

Annular capacity = 0.6946 ft³/ft

b) Casing capacity, ft³/ft:

Casing capacity, ft³/ft = \( \frac{12.615^2}{183.35} \)

Casing capacity, ft³/ft = 159.13823

Casing capacity = 0.8679 ft³/ft

c) Casing capacity, bbl/ft:

Casing capacity, bbl/ft = \( \frac{12.615^3}{1029.4} \)

Casing capacity, bbl/ft = 159.13823

Casing capacity = 0.1545 bbl/ft

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

Sacks required = 2000 ft x 0.6946 ft³/ft x \( \frac{1.50}{1.59} \) ft³/sk

Sacks required = 1311
Step 3  Determine the number of sacks of TAIL or NEAT cement required:

Sacks required annulus = 1000 ft x 0.6946 ft³/ft x 1.50 ÷ 1.15 ft³/sk
Sacks required annulus = 906
Sacks required casing = 44 ft x 0.8679 ft³/ft ÷ 1.15 ft³/sk
Sacks required casing = 33

Total sacks of TAIL cement required:

Sacks = 906 + 33
Sacks = 939

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

Casing capacity, bbl = (3000 ft — 44 ft) x 0.1545 bbl/ft
Casing capacity = 456.7 bbl

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

Strokes = 456.7 bbl ÷ 0.112 bbl/stk
Strokes = 4078

10. Calculations for the Number of Feet to Be Cemented

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

Step 1  Determine the following capacities:

a) Annular capacity, ft³/ft:

Annular capacity, ft³/ft = \( \frac{D_h \text{ in.}^2 - D_p \text{ in.}^2}{183, 35} \)

b) Casing capacity, ft³/ft:

Casing capacity, ft³/ft = \( \frac{ID \text{ in.}^2}{183 \text{,3.5}} \)

Step 2  Determine the slurry volume, ft³

Slurry vol, ft³ = number of sacks of cement to be used x slurry yield, ft³/sk

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

Cement in = (feet of — setting depth of ) x (casing capacity, ft³/ft) ÷ excess casing, ft³ (casing cementing tool, ft)
Formulas and Calculations

**Step 4** Determine the height of cement in the annulus — feet of cement:
Feet = (slurry vol, ft$^3$ — cement remaining in casing, ft$^3$) + (annular capacity, ft$^3$/ft) ÷ excess

**Step 5** Determine the depth of the top of the cement in the annulus:
Depth ft = casing setting depth, ft — ft of cement in annulus

**Step 6** Determine the number of barrels of mud required to displace the cement:
Barrels = feet drill pipe x drill pipe capacity, bbl/ft

**Step 7** Determine the number of strokes required to displace the cement:
Strokes = bbl required to displace cement ÷ pump output, bbl/stk

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

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

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

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

**Step 1** Determine the following capacities:

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

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

Annular capacity = 0.6946 ft$^3$/ft

Annular capacity = 0.6946 ft$^3$/ft
b) Casing capacity, ft\(^3/ft\):

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

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

Casing capacity = 0.8679 ft\(^3/ft\)

**Step 2** Determine the slurry volume, ft\(^3\):

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

Slurry vol = 575 ft\(^3\)

**Step 3** Determine the amount of cement, ft\(^3\), to be left in the casing:

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

Cement in casing, ft\(^3\) = 86.79 ft\(^3\)

**Step 4** Determine the height of the cement in the annulus — feet of cement:

\[
\text{Feet} = \frac{(575 \text{ ft}^3 - 86.79 \text{ ft}^3)}{0.6946 \text{ ft}^3/\text{ft}} \div 1.50
\]

Feet = 468.58

**Step 5** Determine the depth of the top of the cement in the annulus:

\[
\text{Depth} = 3000 \text{ ft} - 468.58 \text{ ft}
\]

Depth = 2531.42 ft

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

\[
\text{Barrels} = 2900 \text{ ft} \times 0.01776 \text{ bbl/ft}
\]

Barrels = 51.5

**Step 7** Determine the number of strokes required to displace the cement:

\[
\text{Strokes} = 51.5 \text{ bbl} \times 0.136 \text{ bbl/stk}
\]

Strokes = 379

---

### 11. Setting a Balanced Cement Plug

**Step 1** Determine the following capacities:

a) Annular capacity, ft\(^3/ft\), between pipe or tubing and hole or casing:

\[
\text{Annular capacity, ft}^3/ft = \frac{Dh \text{ in.}^2 - Dp \text{ in.}^2}{183.35}
\]
b) Annular capacity, ft/bbl between pipe or tubing and hole or casing:

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

c) Hole or casing capacity, ft$^3$/ft:

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

d) Drill pipe or tubing capacity, ft$^3$/ft:

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

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

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

**Step 2** Determine the number of SACKS of cement required for a given length of plug,

**OR** determine the FEET of plug for a given number of sacks of cement:

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

\[
\text{Sacks of cement} = \text{plug length, ft} \times \text{hole or casing capacity ft}^3/\text{ft} \times \text{excess ÷ slurry yield, ft}^3/\text{sk}
\]

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

**OR**

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

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

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

**Step 3** Determine the spacer volume (usually water), bbl, to be pumped behind the slurry to balance the plug:

\[
\text{Spacer vol, bbl} = \frac{\text{annular capacity, ft/bbl} \times \text{excess} \times \text{spac vol ahead, bbl}}{\text{pipe or tubing capacity, ft/bbl}}
\]

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

**Step 4** Determine the plug length, ft, before the pipe is withdrawn:

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

**NOTE:** If no excess is to be used, simply omit the excess step.
**Step 5** Determine the fluid volume, bbl, required to spot the plug:

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

*Example 1:* A 300 ft plug is to be placed at a depth of 5000 ft. The open hole size is 8-1/2 in. and the drill pipe is 3-1/2 in. — 13.3 lb/ft; ID — 2.764 in. Ten barrels of water are to be pumped ahead of the slurry. Use a slurry yield of 1.15 ft³/sk. Use 25% as excess slurry volume:

Determine the following:

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

**Step 1** Determined the following capacities:

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

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

\[
\text{Annular capacity} = 0.3272 \text{ ft}^3/\text{ft}
\]

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

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

\[
\text{Annular capacity} = 17.1569 \text{ ft/bbl}
\]

c) Hole capacity, ft³/ft:

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

\[
\text{Hole capacity} = 0.3941 \text{ ft}^3/\text{ft}
\]

d) Drill pipe capacity, bbl/ft:

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

\[
\text{Drill pipe capacity} = 0.00742 \text{ bbl/ft}
\]

e) Drill pipe capacity, ft³/ft:

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

\[
\text{Drill pipe capacity} = 0.0417 \text{ ft}^3/\text{ft}
\]
**Step 2** Determine the number of sacks of cement required:

Sacks of cement = 300 ft x 0.3941 ft³/ft x 1.25 ÷ 1.15 ft³/sk
Sacks of cement = 129

**Step 3** Determine the spacer volume (water), bbl, to be pumped behind the slurry to balance the plug:

Spacer vol, bbl = 17.1569 ft/bbl ÷ 1.25 x 10 bbl x 0.00742 bbl/ft
Spacer vol = 1.018 bbl

**Step 4** Determine the plug length, ft, before the pipe is withdrawn:

Plug length, ft = (129 sk x 1.15 ft³/sk) ÷ (0.3272 ft³/ft x 1.25 + 0.0417 ft³/ft)
Plug length, ft = 148.35 ft³ ÷ 0.4507 ft³/ft
Plug length = 329 ft

**Step 5** Determine the fluid volume, bbl, required to spot the plug:

Vol, bbl = [(5000 ft — 329 ft) x 0.00742 bbl/ft] — 1.0 bbl
Vol, bbl = 34.66 bbl — 1.0 bbl
Volume = 33.6 bbl

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

A cement plug with 100 sk of cement is to be used in an 8-1/2 in. hole. Use 1.15 ft³/sk for the cement slurry yield. The capacity of 8-1/2 in. hole = 0.3941 ft³/ft. Use 50% as excess slurry volume:

Feet = 100 sk x 1.15 ft³/sk ÷ 0.3941 ft³/ft ÷ 1.50
Feet = 194.5

---

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

1. Determine the hydrostatic pressure exerted by the cement and any mud remaining in the annulus.

2. Determine the hydrostatic pressure exerted by the mud and cement remaining in the casing.

3. Determine the differential pressure.

**Example:** 9-5/8 in. casing — 43.5 lb/ft in 12-1/4 in. hole: Well depth = 8000 ft
Cementing program: LEAD slurry 2000 ft = 13.8 lb/gal
TAIL slurry 1000 ft = 15.8 lb/gal
Mud weight = 10.0 lb/gal
Float collar (No. of feet above shoe) = 44 ft
Determine the total hydrostatic pressure of cement and mud in the annulus

a) Hydrostatic pressure of mud in annulus:

\[
\text{HP, psi} = 10.0 \text{ lb/gal} \times 0.052 \times 5000 \text{ ft} \\
\text{HP} = 2600 \text{ psi}
\]

b) Hydrostatic pressure of LEAD cement:

\[
\text{HP, psi} = 13.8 \text{ lb/gal} \times 0.052 \times 2000 \text{ ft} \\
\text{HP} = 1435 \text{ psi}
\]

c) Hydrostatic pressure of TAIL cement:

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

d) Total hydrostatic pressure in annulus:

\[
\text{psi} = 2600 \text{ psi} + 1435 \text{ psi} + 822 \text{ psi} \\
\text{psi} = 4857
\]

Determine the total pressure inside the casing

a) Pressure exerted by the mud:

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

b) Pressure exerted by the cement:

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

c) Total pressure inside the casing:

\[
\text{psi} = 4137 \text{ psi} + 36 \text{ psi} \\
\text{psi} = 4173
\]

Differential pressure

\[
\text{P}_d = 4857 \text{ psi} - 4173 \text{ psi} \\
\text{P}_d = 684 \text{ psi}
\]
13. **Hydraulicing Casing**

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

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

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

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

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

**Determine the area, sq in., below the shoe**

\[
\text{Area, sq in.} = \text{casing diameter, in.}^2 \times 0.7854
\]

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

\[
\text{Force, lb} = \text{area, sq in.} \times \text{differential pressure between cement and mud, psi}
\]

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

\[
\text{Weight, lb} = \text{casing wt, lb/ft} \times \text{length, ft} \times \text{buoyancy factor}
\]

**Determine the difference in force, lb**

\[
\text{Differential force, lb} = \text{upward force, lb} - \text{downward force, lb}
\]

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

\[
\text{psi} = \text{force, lb} - \text{area, sq in.}
\]

**Mud weight increase to balance pressure**

\[
\text{Mud wt, ppg} = \text{pressure required} \div 0.052 \div \text{casing length, ft to balance forces, psi}
\]

**New mud weight, ppg**

\[
\text{Mud wt, ppg} = \text{mud wt increase, ppg} \div \text{mud wt, ppg}
\]

**Check the forces with the new mud weight**

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

b) \[
\text{psi} = \text{difference in pressure gradients, psi/ft} \times \text{casing length, ft}
\]

c) \[
\text{Upward force, lb} = \text{pressure, psi} \times \text{area, sq in.}
\]

d) \[
\text{Difference in} = \text{upward force, lb} - \text{downward force, lb}
\]
Example:  Casing size = 13 3/8 in. 54 lb/ft  Cement weight = 15.8 ppg
Mud weight = 8.8 ppg  Buoyancy factor = 0.8656
Well depth = 164 ft (50 m)

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

\[
\text{psi/ft} = (15.8 - 8.8) \times 0.052 \\
\text{psi/ft} = 0.364
\]

**Determine the differential pressure between the cement and the mud**

\[
\text{psi} = 0.364 \text{ psi/ft} \times 164 \text{ ft} \\
\text{psi} = 60
\]

**Determine the area, sq in., below the shoe**

\[
\text{area, sq in.} = 13.3752 \times 0.7854 \\
\text{area,} = 140.5 \text{ sq in.}
\]

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

\[
\text{Force, lb} = 140.5 \text{ sq in.} \times 60 \text{ psi} \\
\text{Force} = 8430 \text{ lb}
\]

**Determine the downward force. This is the weight of the casing**

\[
\text{Weight, lb} = 54.5 \text{ lb/ft} \times 164 \text{ ft} \times 0.8656 \\
\text{Weight} = 7737 \text{ lb}
\]

**Determine the difference in force, lb**

\[
\text{Differential force, lb} = \text{downward force, lb} - \text{upward force, lb} \\
\text{Differential force, lb} = 7737 \text{ lb} - 8430 \text{ lb} \\
\text{Differential force} = -693 \text{ lb}
\]

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

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

\[
\text{psi} = 693 \text{ lb} \div 140.5 \text{ sq in.} \\
\text{psi} = 4.9
\]

**Mud weight increase to balance pressure**

\[
\text{Mud wt, ppg} = 4.9 \text{ psi} \div 0.052 \div 164 \text{ ft} \\
\text{Mud wt} = 0.57 \text{ ppg}
\]
New mud weight, ppg

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

Check the forces with the new mud weight

a)  psi/ft = (15.8 — 9.4) x 0.052
    psi/ft = 0.3328

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

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

d)  Differential force, lb = downward force — upward force
    Differential force, lb = 7737 lb — 7668 lb
    Differential force = + 69 lb

14. Depth of a Washout

Method 1

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

Depth of washout, ft = strokes required x pump output, bbl/stk ÷ drill pipe capacity, bbl/ft

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

NOTE: A pressure increase was noticed after 360 strokes.

Depth of washout, ft = 360 stk x 0.112 bbl/stk ÷ 0.00742 bbl/ft
Depth of washout = 5434 ft

Method 2

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

Depth of washout, ft = strokes x pump output, ÷ (drill pipe capacity, bbl/ft + annular capacity, bbl/ft) 

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

NOTE: The material pumped down the drill pipe was noticed coming over the shaker after 2680 strokes.

Drill pipe capacity plus annular capacity:

\[ 0.00742 \text{ bbl/ft} + 0.0583 \text{ bbl/ft} = 0.0657 \text{ bbl/ft} \]

Depth of washout, ft = 2680 stk x 0.112 bbl/stk ÷ 0.0657 bbl/ft
Depth of washout = 4569 ft

15. Lost Returns — Loss of Overbalance

Number of feet of water in annulus

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

Bottomhole (BHP) pressure reduction

BHP decrease, psi = (mud wt, ppg — wt of water, ppg) x 0.052 x (ft of water added)

Equivalent mud weight at TD

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

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

Number of feet of water in annulus

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

Bottomhole pressure decrease

BHP decrease, psi = (12.5 ppg — 8.33 ppg) x 0.052 x 1173 ft
BHP decrease = 254 psi

Equivalent mud weight at TD

EMW, ppg = 12.5 — (254 psi ÷ 0.052 — 10,000 ft)
EMW = 12.0 ppg
16. **Stuck Pipe Calculations**

**Determine the feet of free pipe and the free point constant**

**Method 1**

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

**Table 2-2**

**Drill Pipe Stretch Table**

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

Feet of — stretch, in. x free point constant free pipe — pull force in thousands of pounds

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

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

Feet of free pipe = \( \frac{20 \text{ in. x } 9052.5}{35} \)

Feet of free pipe = 5173 ft
Determine free point constant (FPC)

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

\[ \text{FPC} = A_s \times 2500 \]

where: \( A_s \) = pipe wall cross sectional area, sq in.

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

\[
\text{FPC} = (452 - 3.826^2 \times 0.7854) \times 2500 \\
\text{FPC} = 4.407 \times 2500 \\
\text{FPC} = 11,017.5
\]

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

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

a) Determine free point constant (FPC):

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

b) Determine the depth of stuck pipe:

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

Feet of free pipe = 5663 ft

**Method 2**

Free pipe, ft = \( \frac{735,294 \times e \times W_{dp}}{\text{differential pull, lb}} \)

where \( e \) = pipe stretch, in.

\( W_{dp} \) = drill pipe weight, lb/ft (plain end)

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

Weight, lb/ft = \( 2.67 \times \text{pipe OD, in.}^2 - \text{pipe; ID, in.}^2 \)

**Example:** Determine the feet of free pipe using the following data:

5.0 in. drill pipe; ID — 4.276 in.; 19.5 lb/ft
Differential stretch of pipe = 24 in.
Differential pull to obtain stretch = 30,000 lb
Weight, lb/ft = 2.67 \times (5.0^2 - 4.276^2) \\
Weight = 17.93 \text{ lb/ft} \\

Free pipe, ft = \frac{735,294 \times 24 \times 17.93}{30,000} \\
Free pipe = 10,547 \text{ ft} \\

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

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

\[
\text{psi/ft} = (\text{mud wt, ppg} - \text{spotting fluid wt, ppg}) \times 0.052
\]

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

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

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

Data: Mud weight = 11.2 ppg \hspace{1cm} Weight of spotting fluid = 7.0 ppg
Amount of overbalance = 225.0 psi

a) Difference in pressure gradient, psi/ft:

\[
\text{psi/ft} = (11.2 \text{ ppg} - 7.0 \text{ ppg}) \times 0.052 \\
\text{psi/ft} = 0.2184
\]

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

\[
\text{Height, ft} = \frac{225 \text{ psi}}{0.2184 \text{ psi/ft}} \\
\text{Height} = 1030 \text{ ft}
\]

Therefore: Less than 1030 ft of spotting fluid should be used to maintain a safety factor to prevent a kick or blow-out.
17. Calculations Required for Spotting Pills

The following will be determined:

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

**Step 1** Determine the annular capacity, bbl/ft, for drill pipe and drill collars in the annulus:

\[
\text{Annular capacity, bbl/ft} = \frac{D_h \text{ in.}^2 - D_p \text{ in.}^2}{1029.4}
\]

**Step 2** Determine the volume of pill required in the annulus:

\[
V_{opl} \text{ bbl} = \text{annular capacity, bbl/ft} \times \text{section length, ft} \times \text{washout factor}
\]

**Step 3** Determine total volume, bbl, of spotting fluid (pill) required:

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

**Step 4** Determine drill string capacity, bbl:

Barrels = drill pipe/drill collar capacity, bbl/ft x length, ft

**Step 5** Determine strokes required to pump pill:

Strokes = vol of pill, bbl pump output, bbl/stk

**Step 6** Determine number of barrels required to chase pill:

Barrels = drill string vol, bbl — vol left in drill string, bbl

**Step 7** Determine strokes required to chase pill:

Strokes = bbl required to chase pill ÷ pump output, + strokes required to displace surface system

**Step 8** Total strokes required to spot the pill:

Total strokes = strokes required to pump pill + strokes required to chase pill

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

<table>
<thead>
<tr>
<th>Data:</th>
<th>Well depth</th>
<th>10,000 ft</th>
<th>Pump output</th>
<th>0.117 bbl/stk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hole diameter</td>
<td>8-1/2 in.</td>
<td></td>
<td>Washout factor</td>
<td>20%</td>
</tr>
<tr>
<td>Drill pipe</td>
<td>5.0 in. 19.5 lb/ft</td>
<td></td>
<td>Drill collars</td>
<td>6-1/2 in. OD x 2-1/2 in. ID</td>
</tr>
<tr>
<td>capacity</td>
<td>0.01776 bbl/ft</td>
<td></td>
<td>capacity</td>
<td>0.006 1 bbl/ft</td>
</tr>
<tr>
<td>length</td>
<td>9400 ft</td>
<td></td>
<td>length</td>
<td>600 ft</td>
</tr>
</tbody>
</table>
Formulas and Calculations

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

**Step 1** Annular capacity around drill pipe and drill collars:

a) Annular capacity around drill collars:

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

Annular capacity = 0.02914 bbl/ft

b) Annular capacity around drill pipe:

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

Annular capacity = 0.0459 bbl/ft

**Step 2** Determine total volume of pill required in annulus:

a) Volume opposite drill collars:

\[
\text{Vol, bbl} = 0.02914 \text{ bbl/ft} \times 600 \text{ ft} \times 1.20
\]

Vol = 21.0 bbl

b) Volume opposite drill pipe:

\[
\text{Vol, bbl} = 0.0459 \text{ bbl/ft} \times 200 \text{ ft} \times 1.20
\]

Vol = 11.0 bbl

c) Total volume bbl, required in annulus:

\[
\text{Vol, bbl} = 21.0 \text{ bbl} + 11.0 \text{ bbl}
\]

Vol = 32.0 bbl

**Step 3** Total bbl of spotting fluid (pill) required:

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

Barrels = 56.0 bbl

**Step 4** Determine drill string capacity:

a) Drill collar capacity, bbl:

\[
\text{Capacity, bbl} = 0.0062 \text{ bbl/ft} \times 600 \text{ ft}
\]

Capacity = 3.72 bbl

b) Drill pipe capacity, bbl:

\[
\text{Capacity, bbl} = 0.01776 \text{ bbl/ft} \times 9400 \text{ ft}
\]

Capacity = 166.94 bbl
c) Total drill string capacity, bbl:

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

**Step 5**  Determine strokes required to pump pill:

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

**Step 6**  Determine bbl required to chase pill:

Barrels = 170.6 bbl — 24 bbl
Barrels = 146.6

**Step 7**  Determine strokes required to chase pill:

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

**Step 8**  Determine strokes required to spot the pill:

Total strokes = 479 + 1333
Total strokes = 1812

---

18. **Pressure Required to Break Circulation**

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

\[ P_{gs} = \left( \frac{y}{300 \times d} \right) L \]

where  
- \( P_{gs} \) = pressure required to break gel strength, psi
- \( y \) = 10 mm gel strength of drilling fluid, lb/100 sq ft
- \( d \) = inside diameter of drill pipe, in.
- \( L \) = length of drill string, ft

**Example:**  
\( y = 10 \text{ lb/100 sq ft} \quad d = 4.276 \text{ in.} \quad L = 12,000 \text{ ft} \)

\[ P_{gs} = (10 ÷ 300 - 4.276) \times 12,000 \text{ ft} \]
\[ P_{gs} = 0.007795 \times 12,000 \text{ ft} \]
\[ P_{gs} = 93.5 \text{ psi} \]

Therefore, approximately 94 psi would be required to break circulation.
Pressure required to overcome the mud’s gel strength in the annulus

\[ P_{gs} = \frac{y}{300 (D_h - D_p)} \times L \]

where
- \( P_{gs} \) = pressure required to break gel strength, psi
- \( L \) = length of drill string, ft
- \( y \) = 10 mm. gel strength of drilling fluid, lb/100 sq ft
- \( D_h \) = hole diameter, in.
- \( D_p \) = pipe diameter, in.

Example:
- \( L = 12,000 \) ft
- \( y = 10 \) lb/100 sq ft
- \( D_h = 12-1/4 \) in.
- \( D_p = 5.0 \) in.

\[ P_{gs} = \frac{10}{300 \times (12.25 - 5.0)} \times 12,000 \text{ ft} \]
\[ P_{gs} = \frac{10}{2175} \times 12,000 \text{ ft} \]
\[ P_{gs} = 55.2 \text{ psi} \]

Therefore, approximately 55 psi would be required to break circulation.

References


CHAPTER THREE

DRILLING FLUIDS
1. Increase Mud Density

Mud weight, ppg, increase with barite (average specific gravity of barite - 4.2)

Barite, sk/100 bbl = \( \frac{1470 \times (W_2 - W_1)}{35 - W_2} \)

*Example:* Determine the number of sacks of barite required to increase the density of 100 bbl of 12.0 ppg \( W_1 \) mud to 14.0 ppg \( W_2 \):

Barite sk/100 bbl = \( \frac{1470 \times (14.0 - 12.0)}{35 - 14.0} \)

Barite, sk/100 bbl = 2940

Barite = 140 sk/100 bbl

Volume increase, bbl, due to mud weight increase with barite

Volume increase, per 100 bbl = \( \frac{100 \times (W_2 - W_1)}{35 - W_2} \)

*Example:* Determine the volume increase when increasing the density from 12.0 ppg \( W_1 \) to 14.0 ppg \( W_2 \):

Volume increase, per 100 bbl = \( \frac{100 \times (14.0 - 12.0)}{35 - 14.0} \)

Volume increase, per 100 bbl = 200

Volume increase = 9.52 bbl per 100 bbl

Starting volume, bbl, of original mud weight required to give a predetermined final volume of desired mud weight with barite

Starting volume, bbl = \( \frac{V_F \times (35 - W_2)}{35 - W_1} \)

*Example:* Determine the starting volume, bbl, of 12.0 ppg \( W_1 \) mud required to achieve 100 bbl \( V_F \) of 14.0 ppg \( W_2 \) mud with barite:

Starting volume, bbl = \( \frac{100 \times (35 - 14.0)}{35 - 12.0} \)

Starting volume, bbl = 2100

Starting volume = 91.3 bbl
Mud weight increase with calcium carbonate (SG — 2.7)

**NOTE:** The maximum practical mud weight attainable with calcium carbonate is 14.0 ppg.

\[
\text{Sacks/ 100 bbl} = \frac{945(W_2 - W_1)}{22.5 - W_2}
\]

**Example:** Determine the number of sacks of calcium carbonate/100 bbl required to increase the density from 12.0 ppg \(W_1\) to 13.0 ppg \(W_2\):

\[
\begin{align*}
\text{Sacks/ 100 bbl} & = \frac{945(13.0 - 12.0)}{22.5 - 13.0} \\
& = \frac{945}{9.5} \\
& = 99.5
\end{align*}
\]

**Volume increase, bbl, due to mud weight increase with calcium carbonate**

\[
\text{Volume increase, per 100 bbl} = \frac{100(W_2 - W_1)}{22.5 - W_2}
\]

**Example.** Determine the volume increase, bbl/100 bbl, when increasing the density from 12.0 ppg \(W_3\) to 13.0 ppg \(W_2\):

\[
\begin{align*}
\text{Volume increase, per 100 bbl} & = \frac{100(13.0 - 12.0)}{22.5 - 13.0} \\
& = \frac{100}{9.5} \\
& = 10.53 \text{ bbl per 100 bbl}
\end{align*}
\]

**Starting volume, bbl, of original mud weight required to give a predetermined final volume of desired mud weight with calcium carbonate**

\[
\text{Starting volume, bbl} = \frac{V_F (22.5 - W_2)}{22.5 - W_1}
\]

**Example:** Determine the starting volume, bbl, of 12.0 ppg \(W_1\) mud required to achieve 100 bbl \(V_F\) of 13.0 ppg \(W_2\) mud with calcium carbonate:

\[
\begin{align*}
\text{Starting volume, bbl} & = \frac{100(22.5 - 13.0)}{22.5 - 12.0} \\
& = \frac{950}{10.5} \\
& = 90.5 \text{ bbl}
\end{align*}
\]
**Mud weight increase with hematite (SG — 4.8)**

Hematite, sk/100 bbl = \(\frac{1680 \cdot (W_2 - W_1)}{40 - W_2}\)

*Example:* Determine the hematite, sk/100 bbl, required to increase the density of 100 bbl of 12.0 ppg \((W_1)\) to 14.0 ppg \((W_2)\):

Hematite, sk/100 bbl = \(\frac{1680 \cdot (14.0 - 12.0)}{40 - 14.0}\)

Hematite, sk/100 bbl = \(\frac{3360}{26}\)

Hematite = 129.2 sk/100 bbl

**Volume increase, bbl, due to mud weight increase with hematite**

Volume increase, per 100 bbl = \(\frac{100 \cdot (W_2 - W_1)}{40 - W_2}\)

*Example:* Determine the volume increase, bbl/100 bbl, when increasing the density from 12.0 ppg \((W_1)\) to 14.0 ppg \((W_2)\):

Volume increase, per 100 bbl = \(\frac{100 \cdot (14.0 - 12.0)}{40 - 14.0}\)

Volume increase, per 100 bbl = \(\frac{200}{26}\)

Volume increase = 7.7 bbl per 100 bbl

**Starting volume, bbl, of original mud weight required to give a predetermined final volume of desired mud weight with hematite**

Starting volume, bbl = \(\frac{V_F \cdot (40.0 - W_2)}{40 - W_1}\)

*Example:* Determine the starting volume, bbl, of 12.0 ppg \((W_1)\) mud required to achieve 100 bbl \((V_F)\) of 14.0 ppg \((W_2)\) mud with hematite:

Starting volume, bbl = \(\frac{100 \cdot (40 - 14.0)}{40 - 12.0}\)

Starting volume, bbl = \(\frac{2600}{28}\)

Starting volume = 92.9 bbl
2. **Dilution**

**Mud weight reduction with water**

Water, bbl = $\frac{V_1(W_1 - W_2)}{W_2 - Dw}$

*Example:* Determine the number of barrels of water weighing 8.33 ppg (Dw) required to reduce 100 bbl ($V_1$) of 14.0 ppg ($W_1$) to 12.0 ppg ($W_2$):

Water, bbl = $\frac{100(14.0 - 12.0)}{12.0 - 8.33}$

Water, bbl = 2000

Water = 54.5 bbl

**Mud weight reduction with diesel oil**

Diesel, bbl = $\frac{V_1(W_1 - W_2)}{W_2 - Dw}$

*Example:* Determine the number of barrels of diesel weighing 7.0 ppg (Dw) required to reduce 100 bbl ($V_1$) of 14.0 ppg ($W_1$) to 12.0 ppg ($W_2$):

Diesel, bbl = $\frac{100(14.0 - 12.0)}{12.0 - 7.0}$

Diesel, bbl = 200

Diesel = 40 bbl

3. **Mixing Fluids of Different Densities**

Formula: $(V_1 D_1) + (V_2 D_2) = V_F D_F$

where $V_1$ = volume of fluid 1 (bbl, gal, etc.) $D_1$ = density of fluid 1 (ppg, lb/ft$^3$, etc.)

$V_2$ = volume of fluid 2 (bbl, gal, etc.) $D_2$ = density of fluid 2 (ppg, lb/ft$^3$, etc.)

$V_F$ = volume of final fluid mix $D_F$ = density of final fluid mix

*Example 1:* A limit is placed on the desired volume:

Determine the volume of 11.0 ppg mud and 14.0 ppg mud required to build 300 bbl of 11.5 ppg mud:

Given: 400 bbl of 11.0 ppg mud on hand, and 400 bbl of 14.0 ppg mud on hand
Solution: let \( V_1 = \text{bbl of 11.0 ppg mud} \)
\( V_2 = \text{bbl of 14.0 ppg mud} \)

then

a) \( V_1 + V_2 = 300 \text{ bbl} \)
b) \( (11.0) V_1 + (14.0) V_2 = (11.5)(300) \)

Multiply Equation A by the density of the lowest mud weight \( (D_1 = 11.0 \text{ ppg}) \) and subtract the result from Equation B:

\[
\begin{align*}
\text{b)} & \quad (11.0) (V_1) + (14.0) (V_2) = 3450 \\
\text{a)} & \quad (11.0) (V_1) + (11.0) (V_2) = 3300 \\
& \quad 0 (3.0) (V_2) = 150 \\
& \quad 3 \quad V_2 = 150 \\
& \quad V_2 = \frac{150}{3} \\
& \quad \text{Therefore:} \\
& \quad V_2 = 50 \text{ bbl of 14.0 ppg mud} \\
\end{align*}
\]

Therefore:
\( V_2 = 50 \text{ bbl of 14.0 ppg mud} \)
\( V_1 + V_2 = 300 \text{ bbl} \)
\( V_1 = 300 — 50 \)
\( V_1 = 250 \text{ bbl of 11.0 ppg mud} \)

Check:
\( V_1 = 50 \text{ bbl} \quad D_1 = 14.0 \text{ ppg} \)
\( V_2 = 150 \text{ bbl} \quad D_2 = 11.0 \text{ ppg} \)
\( V_F = 300 \text{ bbl} \quad D_F = \text{final density, ppg} \)

\[
\begin{align*}
(50) (14.0) + (250) (11.0) & = 300 D_F \\
700 + 2750 & = 300 D_F \\
3450 & = 300 D_F \\
3450 \div 300 & = D_F \\
11.5 \text{ ppg} & = D_F \\
\end{align*}
\]

Example 2: No limit is placed on volume:

Determine the density and volume when the two following muds are mixed together:

Given: 400 bbl of 11.0 ppg mud, and
400 bbl of 14.0 ppg mud

Solution: let \( V_1 = \text{bbl of 11.0 ppg mud} \)
\( V_2 = \text{bbl of 14.0 ppg mud} \)
\( V_F = \text{final volume, bbl} \)
\( D_1 = \text{density of 11.0 ppg mud} \)
\( D_2 = \text{density of 14.0 ppg mud} \)
\( D_F = \text{final density, ppg} \)

Formula: \( (V_1 D_1) + (V_2 D_2) = V_F D_F \)

\[
\begin{align*}
(400) (11.0) + (400) (14.0) & = 800 D_F \\
4400 + 5600 & = 800 D_F \\
10,000 & = 800 D_F \\
10,000 \div 800 & = D_F \\
12.5 \text{ ppg} & = D_F \\
\end{align*}
\]
Therefore: final volume = 800 bbl
final density = 12.5 ppg

4. Oil Based Mud Calculations

Density of oil/water mixture being used

\[(V_1)(D_1) + (V_2)(D_2) = (V_1 + V_2)D_F\]

*Example:* If the oil/water (o/w) ratio is 75/25 (75% oil, \(V_1\), and 25% water \(V_2\)), the following material balance is set up:

**NOTE:** The weight of diesel oil, \(D_1 = 7.0 \text{ ppg}\)
The weight of water, \(D_2 = 8.33 \text{ ppg}\)

\[
(0.75)(7.0) + (0.25)(8.33) = (0.75 + 0.25)D_F
\]

\[
5.25 + 2.0825 = 1.0 D_F
\]

\[
7.33 = D_F
\]

Therefore: The density of the oil/water mixture = 7.33 ppg

Starting volume of liquid (oil plus water) required to prepare a desired volume of mud

\[
SV = \frac{35 - W_2 \times DV}{35 - W_1}
\]

where \(SV\) = starting volume, bbl \(W_1\) = initial density of oil/water mixture, ppg
\(W_2\) = desired density, ppg \(Dv\) = desired volume, bbl

*Example:* \(W_1 = 7.33 \text{ ppg (o/w ratio — 75/25)}\) \(W_2 = 16.0 \text{ ppg}\) \(Dv = 100 \text{ bbl}\)

Solution:

\[
SV = \frac{35 - 16}{35 - 7.33} \times 100
\]

\[
SV = \frac{19}{27.67} \times 100
\]

\[
SV = 68.7 \text{ bbl}
\]

Oil/water ratio from retort data

Obtain the percent-by-volume oil and percent-by-volume water from retort analysis or mud still analysis. From the data obtained, the oil/water ratio is calculated as follows:
Formulas and Calculations

a) % oil in liquid phase = \( \frac{\% \text{ by vol oil}}{\% \text{ by vol oil} + \% \text{ by vol water}} \times 100 \)

b) % water in liquid phase = \( \frac{\% \text{ by vol water}}{\% \text{ by vol oil} + \% \text{ by vol water}} \times 100 \)

c) Result: The oil/water ratio is reported as the percent oil and the percent water.

Example: Retort analysis:  % by volume oil = 51
% by volume water = 17
% by volume solids = 32

Solution:

a) % oil in liquid phase = \( \frac{51}{51 \times 17} \times 100 \)

% oil in liquid phase = 75

b) % water in liquid phase = \( \frac{17}{51 + 17} \times 100 \)

% water in liquid phase = 25

c) Result: Therefore, the oil/water ratio is reported as 75/25: 75% oil and 25% water.

Changing oil/water ratio

NOTE: If the oil/water ratio is to be increased, add oil; if it is to be decreased, add water.

Retort analysis: % by volume oil = 51
% by volume water = 17
% by volume solids = 32

The oil/water ratio is 75/25.

Example 1: Increase the oil/water ratio to 80/20:

In 100 bbl of this mud, there are 68 bbl of liquid (oil plus water). To increase the oil/water ratio, add oil. The total liquid volume will be increased by the volume of the oil added, but the water volume will not change. The 17 bbl of water now in the mud represents 25% of the liquid volume, but it will represent only 20% of the new liquid volume.

Therefore: let x = final liquid volume
then, \( 0.20x = 17 \)

\[ x = 17 / 0.20 \]
\[ x = 85 \text{ bbl} \]

The new liquid volume = 85 bbl
Barrels of oil to be added:

Oil, bbl = new liquid vol — original liquid vol
Oil, bbl = 85 — 68
Oil = 17 bbl oil per 100 bbl of mud

Check the calculations. If the calculated amount of liquid is added, what will be the resulting oil/water ratio?

\[
\% \text{ oil in liquid phase} = \frac{\text{original vol oil} + \text{new vol oil}}{\text{original liquid oil} + \text{new oil added}} \times 100
\]

\[
\% \text{ oil in liquid phase} = \frac{51+17}{68 + 17} \times 100
\]

\[
\% \text{ oil in liquid phase} = 80
\]
\[
\% \text{ water would then be:} 100 — 80 = 20
\]

Therefore: The new oil/water ratio would be 80/20.

**Example 2:** Change the oil/water ratio to 70/30:

As in Example I, there are 68 bbl of liquid in 100 bbl of this mud. In this case, however, water will be added and the volume of oil will remain constant. The 51 bbl of oil represents 75% of the original liquid volume and 70% of the final volume:

Therefore: let \( x \) = final liquid volume

then, \( 0.70x = 51 \)

\[
x = 51 \div 0.70
\]

\[
x = 73 \text{ bbl}
\]

Barrels of water to be added:

Water, bbl = new liquid vol — original liquid vol
Water, bbl = 73 — 68
Water = 5 bbl of water per 100 bbl of mud

Check the calculations. If the calculated amount of water is added, what will be the resulting oil/water ratio?

\[
\% \text{ water in liquid phase} = \frac{17 + 5}{68 + 5} \times 100
\]

\[
\%\text{ water in liquid} = 30
\]
\[
\% \text{ oil in liquid phase} = 100 — 30 = 70
\]

Therefore, the new oil/water ratio would be 70/30.
5. Solids Analysis

Basic solids analysis calculations

NOTE: Steps 1 — 4 are performed on high salt content muds. For low chloride muds begin with Step 5.

Step 1 Percent by volume saltwater (SW)

$$SW = (5.88 \times 10^{-8}) \times [(ppm \ Cl)^{1.2} + 1] \times \% \ by \ vol \ water$$

Step 2 Percent by volume suspended solids (SS)

$$SS = 100 — \% \ by \ vol \ oil — \% \ by \ vol \ SW$$

Step 3 Average specific gravity of saltwater (ASGsw)

$$ASGsw = (ppm \ Cl)^{0.95} \times (1.94 \times 10^{-6}) + 1$$

Step 4 Average specific gravity of solids (ASG)

$$ASG = \frac{(12 \times MW) — \% \ by \ vol \ SW \times ASGsw — (0.84 \times \% \ by \ vol \ oil)}{SS}$$

Step 5 Average specific gravity of solids (ASG)

$$ASG = \frac{(12 \times MW) — \% \ by \ vol \ water — \% \ by \ vol \ oil}{\% \ by \ vol \ solids}$$

Step 6 Percent by volume low gravity solids (LGS)

$$LGS = \frac{\% \ by \ volume \ solids \times (4.2 — ASG)}{1.6}$$

Step 7 Percent by volume barite

Barite, % by vol = % by vol solids — % by vol LGS

Step 8 Pounds per barrel barite

Barite, lb/bbl = % by vol barite x 14.71

Step 9 Bentonite determination

If cation exchange capacity (CEC)/methytene blue test (MBT) of shale and mud are KNOWN:

a) Bentonite, lb/bbl:

$$Bentonite, \ lb/bbl = 1 \div (1 — (S \div 65) \times (M — 9 \times (S \div 65)) \times \% \ by \ vol \ LGS$$

Where $S = CEC \ of \ shale \quad M = CEC \ of \ mud$
b) Bentonite, % by volume:

Bent, % by vol = bentonite, lb/bbl ÷ 9.1

If the cation exchange capacity (CEC)/methylene blue (MBT) of SHALE is UNKNOWN:

a) Bentonite, % by volume = \( \frac{M}{8} \) — % by volume LGS

where M = CEC of mud

b) Bentonite, lb/bbl = bentonite, % by vol x 9.1

**Step 10** Drilled solids, % by volume

Drilled solids, % by vol = LGS, % by vol — bentonite, % by vol

**Step 11** Drilled solids, lb/bbl

Drilled solids, lb/bbl = drilled solids, % by vol x 9.1

*Example:*

Mud weight = 16.0 ppg  
Chlorides = 73,000 ppm  
CEC of mud = 30 lb/bbl  
CEC of shale = 7 lb/bbl  
Retort Analysis:  
water = 57.0% by volume  
oil = 7.5% by volume  
solids = 35.5% by volume

1. Percent by volume saltwater (SW)

\[
SW = \left[ (5.88 \times 10^{-8})(73,000)^{1.2} + 1 \right] \times 57 \\
SW = \left[ (5.88 \times 10^{-8} \times 685468.39) + 1 \right] \times 57 \\
SW = (0.0403055 + 1) \times 57 \\
SW = 59.2974 \text{ percent by volume}
\]

2. Percent by volume suspended solids (SS)

\[
SS = 100 - 7.5 - 59.2974 \\
SS = 33.2026 \text{ percent by volume}
\]

3. Average specific gravity of saltwater (ASGsw)

\[
ASGsw = \left[ (73,000)^{0.95} - (1.94 \times 10^{6}) \right] + 1 \\
ASGsw = (41,701.984 \times 1.94^{6}) + 1 \\
ASGsw = 0.0809018 + 1 \\
ASGsw = 1.0809
\]

4. Average specific gravity of solids (ASG)

\[
ASO = \frac{(12 \times 16) - (59.2974 \times 1.0809) - (0.84 \times 7.5)}{33.2026}
\]
Formulas and Calculations

ASG = $\frac{121.60544}{33.2026}$

ASG = 3.6625

5. Because a high chloride example is being used, Step 5 is omitted.

6. Percent by volume low gravity solids (LGS)

$LGS = \frac{33.2026 \times (4.2 - 3.6625)}{1.6}$

$LGS = 11.154$ percent by volume

7. Percent by volume barite

Barite, % by volume $= 33.2026 - 11.154$

Barite $= 22.0486$ % by volume

8. Barite, lb/bbl

Barite, lb/bbl $= 22.0486 \times 14.71$

Barite $= 324.3349$ lb/bbl

9. Bentonite determination

a) lb/bbl $= 1 - (1 - (7 \div 65) \times (30 - 9 \times (7 \div 65)) \times 11.154$

$\text{lb/bbl} = 1.1206897 \times 2.2615385 \times 11.154$

$\text{Bent} = 28.26965$ lb/bbl

b) Bentonite, % by volume

Bent, % by vol $= 28.2696 \div 9.1$

Bent $= 3.10655$% by vol

10. Drilled solids, percent by volume

Drilled solids, % by vol $= 11.154 - 3.10655$

$\text{Drilled solids} = 8.047$% by vol

11. Drilled solids, pounds per barrel

Drilled solids, lb/bbl $= 8.047 \times 9.1$

Drilled solids $= 73.2277$ lb/bbl
6. **Solids Fractions**

**Maximum recommended solids fractions (SF)**

\[
SF = (2.917 \times MW) - 14.17
\]

**Maximum recommended low gravity solids (LGS)**

\[
LGS = \left( \frac{SF}{100} - [0.3125 \times \left( \frac{MW}{8.33} - 1 \right)] \right) \times 200
\]

where  
- \(SF\) = maximum recommended solids fractions, % by vol  
- \(LGS\) = maximum recommended low gravity solids, % by vol  
- \(MW\) = mud weight, ppg

*Example:* Mud weight = 14.0 ppg

Determine: Maximum recommended solids, % by volume  
Low gravity solids fraction, % by volume  
Maximum recommended solids fractions (SF), % by volume:

\[
SF = (2.917 \times 14.0) - 14.17
\]

\[
SF = 40.838 - 14.17
\]

\[
SF = 26.67 \% \text{ by volume}
\]

Low gravity solids (LOS), % by volume:

\[
LGS = \left( \frac{26.67}{100} - [0.3125 \times \left( \frac{14.0}{8.33} - 1 \right)] \right) \times 200
\]

\[
LGS = 0.2667 - (0.3125 \times 0.6807) \times 200
\]

\[
LGS = (0.2667 - 0.2127) \times 200
\]

\[
LGS = 0.054 \times 200
\]

\[
LGS = 10.8 \% \text{ by volume}
\]

7. **Dilution of Mud System**

\[
V_{wm} = \frac{V_m (F_{ct} - F_{cop})}{F_{cop} - F_{ca}}
\]

where  
- \(V_{wm}\) = barrels of dilution water or mud required  
- \(V_m\) = barrels of mud in circulating system  
- \(F_{ct}\) = percent low gravity solids in system  
- \(F_{cop}\) = percent total optimum low gravity solids desired  
- \(F_{ca}\) = percent low gravity solids (bentonite and/or chemicals added)

*Example:* 1000 bbl of mud in system. Total LOS = 6%. Reduce solids to 4%. Dilute with water:
V_{wm} = \frac{1000 \times (6 - 4)}{4}

V_{wm} = \frac{2000}{4}

V_{wm} = 500 \text{ bbl}

If dilution is done with a 2% bentonite slurry, the total would be:

V_{wm} = \frac{1000 \times (6 - 4)}{4 - 2}

V_{wm} = \frac{2000}{2}

V_{wm} = 1000 \text{ bbl}

8. **Displacement — Barrels of Water/Slurry Required**

V_{wm} = \frac{V_{m} \times (F_{ct} - F_{cop})}{F_{ct} - F_{ca}}

where \( V_{wm} \) = barrels of mud to be jetted and water or slurry to be added to maintain constant circulating volume:

*Example:* 1000 bbl in mud system. Total LGS = 6%. Reduce solids to 4%:

V_{wm} = \frac{1000 \times (6 - 4)}{6}

V_{wm} = \frac{2000}{6}

V_{wm} = 333 \text{ bbl}

If displacement is done by adding 2% bentonite slurry, the total volume would be:

V_{wm} = \frac{1000 \times (6 - 4)}{6 - 2}

V_{wm} = \frac{2000}{4}

V_{wm} = 500 \text{ bbl}
9. **Evaluation of Hydrocyclone**

Determine the mass of solids (for an unweighted mud) and the volume of water discarded by one cone of a hydrocyclone (desander or desilter):

Volume fraction of solids (SF):  \[ SF = \frac{MW - 8.22}{13.37} \]

Mass rate of solids (MS):  \[ MS = 19,530 \times SF \times \frac{V}{T} \]

Volume rate of water (WR):  \[ WR = 900 \times (1 - SF) \times \frac{V}{T} \]

where  
- SF = fraction percentage of solids  
- MW = average density of discarded mud, ppg  
- MS = mass rate of solids removed by one cone of a hydrocyclone, lb/hr  
- V = volume of slurry sample collected, quarts  
- T = time to collect slurry sample, seconds  
- WR = volume of water ejected by one cone of a hydrocyclone, gal/hr

**Example:** Average weight of slurry sample collected = 16.0 ppg Sample collected in 45 seconds  
Volume of slurry sample collected = 2 quarts

a) Volume fraction of solids:  
\[ SF = \frac{16.0 - 8.33}{13.37} \]

SF = 0.5737

b) Mass rate of solids:  
\[ MS = 19,530 \times 0.5737 \times \frac{2}{45} \]

MS = 11,204.36 x 0.0444  
MS = 497.97 lb/hr

c) Volume rate of water:  
\[ WR = 900 \times (1 - 0.5737) \times \frac{2}{45} \]

WR = 900 x 0.4263 x 0.0444  
WR = 17.0 gal/hr

10. **Evaluation of Centrifuge**

a) Underflow mud volume:  
\[ QU = \left[ \frac{QM \times (MW - PO)}{PU - PO} \right] - \left[ \frac{QW \times (PO - PW)}{PU - PO} \right] \]
b) Fraction of old mud in Underflow:

\[
FU = \frac{35 - PU}{35 - MW + (QW \div QM) \times (35 - PW)}
\]

c) Mass rate of clay:

\[
QC = \frac{CC \times [QM - (QU \times FU)]}{42}
\]

d) Mass rate of additives:

\[
QC = \frac{CD \times [QM - (QU \times FU)]}{42}
\]

e) Water flow rate into mixing pit:

\[
QP = \frac{[QM \times (35 - MW)] - [QU \times (35 - PU)] - (0.6129 \times QC) - (0.6129 \times QD)}{35 - PW}
\]

f) Mass rate for API barite:

\[
QB = QM - QU - QP - \frac{QC}{21.7} - \frac{QD}{21.7} \times 35
\]

where:

- MW = mud density into centrifuge, ppg
- PU = Underflow mud density, ppg
- QM = mud volume into centrifuge, gal/mm
- PW = dilution water density, ppg
- QW = dilution water volume, gal/mm
- PO = overflow mud density, ppg
- CD = additive content in mud, lb/bbl
- CC = clay content in mud, lb/bbl
- QU = Underflow mud volume, gal/mm
- QC = mass rate of clay, lb/mm
- FU = fraction of old mud in Underflow
- QD = mass rate of additives, lb/mm
- QB = mass rate of API barite, lb/mm
- QP = water flow rate into mixing pit, gal/mm

**Example:**

Mud density into centrifuge (MW) = 16.2 ppg
Mud volume into centrifuge (QM) = 16.5 gal/mm
Dilution water density (PW) = 8.34 ppg
Dilution water volume (QW) = 10.5 gal/mm
Underflow mud density (PU) = 23.4 ppg
Overflow mud density (PO) = 9.3 ppg
Clay content of mud (CC) = 22.5 lb/bbl
Additive content of mud (CD) = 6 lb/bbl

Determine:
- Flow rate of Underflow
- Volume fraction of old mud in the Underflow
- Mass rate of clay into mixing pit
- Mass rate of additives into mixing pit
- Water flow rate into mixing pit
- Mass rate of API barite into mixing pit
a) Underflow mud volume, gal/mm:

\[ QU = \frac{16.5 \times (16.2 - 9.3) - 10.5 \times (9.3 - 8.34)}{23.4 - 9.3} \]

\[ QU = \frac{113.85 - 10.08}{14.1} \]

\[ QU = 7.4 \text{ gal/mm} \]

b) Volume fraction of old mud in the Underflow:

\[ FU = \frac{35 - 23.4}{35 - 16.2 + \left[ \frac{10.5}{16.5} \times (35 - 8.34) \right]} \]

\[ FU = \frac{11.6}{18.8 + (0.63636 \times 26.66)} \]

\[ FU = 0.324\% \]

c) Mass rate of clay into mixing pit, lb/mm:

\[ QC = \frac{22.5 \times [16.5 - (7.4 \times 0.324)]}{42} \]

\[ QC = \frac{22.5 \times 14.1}{42} \]

\[ QC = 7.55 \text{ lb/min} \]

d) Mass rate of additives into mixing pit, lb/mm:

\[ QD = \frac{6 \times [16.5 - (7.4 \times 0.324)]}{42} \]

\[ QD = \frac{6 \times 14.1}{42} \]

\[ QD = 2.01 \text{ lb/mm} \]

e) Water flow into mixing pit, gal/mm:

\[ QP = \frac{16.5 \times (35 - 16.2) - 7.4 \times (35 - 23.4) - (0.6129 \times 7.55) - (0.6129 \times 2)}{(35 - 8.34)} \]

\[ QP = \frac{310.2 - 85.84 - 4.627 - 1.226}{26.66} \]

\[ QP = \frac{218.507}{26.66} \]

\[ QP = 8.20 \text{ gal/mm} \]
f) Mass rate of API barite into mixing pit, lb/mm:

\[ \begin{align*}
QB &= 16.5 - 7.4 - 8.20 - (7.55 \div 21.7) - (2.01 \div 21.7) \times 35 \\
QB &= 16.5 - 7.4 - 8.20 - 0.348 - 0.0926 \times 35 \\
QB &= 0.4594 \times 35 \\
QB &= 16.079 \text{ lb/mm}
\end{align*} \]

**References**


CHAPTER FOUR
PRESSURE CONTROL
1. Kill Sheets and Related Calculations

Normal Kill Sheet

Pre-recorded Data

Original mud weight (OMW) ____________________________ ppg
Measured depth (MD) ________________________________ ft
Kill rate pressure (KRP) __________________ psi @ __________ spm
Kill rate pressure (KRP) __________________ psi @ __________ spm

Drill String Volume

Drill pipe capacity
____________ bbl/ft x ____________ length, ft = ____________ bbl
Drill pipe capacity
____________ bbl/ft x ____________ length, ft = ____________ bbl
Drill collar capacity
____________ bbl/ft x ____________ length, ft = ____________ bbl

Total drill string volume ____________________________ bbl

Annular Volume

Drill collar/open hole
Capacity __________ bbl/ft x ____________ length, ft = ____________ bbl
Drill pipe/open hole
Capacity __________ bbl/ft x ____________ length, ft = ____________ bbl
Drill pipe/casing
Capacity __________ bbl/ft x ____________ length, ft = ____________ bbl

Total barrels in open hole ____________________________ bbl
Total annular volume ____________________________ bbl

Pump Data

Pump output __________ bbl/stk @ _______________ % efficiency
Formulas and Calculations

Surface to bit strokes:
Drill string volume ______ bbl ÷ ______ pump output, bbl/stk = ______ stk

Bit to casing shoe strokes:
Open hole volume ______ bbl ÷ ______ pump output, bbl/stk = ______ stk

Bit to surface strokes:
Annulus volume ______ bbl ÷ ______ pump output, bbl/stk = ______ stk

Maximum allowable shut-in casing pressure:
Leak-off test _____ psi, using __ ppg mud weight @ casing setting depth of _______ TVD

Kick data
SIDPP _______________________________________ psi
SICP _______________________________________ psi
Pit gain _______________________________________ bbl
True vertical depth _____________________________ ft

Calculations

Kill Weight Mud (KWM)
= SIDPP _____ psi ÷ 0.052 ÷ TVD _____ ft + OMW _____ ppg = ________ ppg

Initial Circulating Pressure (ICP)
= SIDPP_______ psi + KRP _________ psi = _________ psi

Final Circulating Pressure (FCP)
= KWM ______ ppg x KRP ______ psi ÷ OMW ______ ppg = _____________ psi

Psi/stroke
ICP psi — FCP ___________ psi ÷ strokes to bit __________ = __________ psi/stk
Pressure Chart

<table>
<thead>
<tr>
<th>Strokes</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>&lt; Initial Circulating Pressure</td>
</tr>
</tbody>
</table>

Strokes to Bit > <Final Circulating Pressure

Example: Use the following data and fill out a kill sheet:

Data:  
- Original mud weight = 9.6 ppg
- Measured depth = 10,525 ft
- Kill rate pressure @ 50 spm = 1000 psi
- Kill rate pressure @ 30 spm = 600 psi
- Drill string:
  - drill pipe 5.0 in. — 19.5 lb/ft capacity = 0.01776 bbl/ft
  - HWDP 5.0 in. 49.3 lb/ft capacity = 0.00883 bbl/ft
  - length = 240 ft
- drill collars 8.0 in. OD — 3.0 in. ID capacity = 0.0087 bbl/ft
  - length = 360 ft
Annulus:
- hole size = 12 1/4 in.
- drill collar/open hole capacity = 0.0836 bbl/ft
- drill pipe/open hole capacity = 0.1215 bbl/ft
- drill pipe/casing capacity = 0.1303 bbl/ft
Mud pump (7 in. x 12 in. triplex @ 95% eff.) = 0.136 bbl/ft
- Leak-off test with 9.0 ppg mud = 1130 psi
- Casing setting depth = 4800 ft
- Shut-in drill pipe pressure = 480 psi
- Shut-in casing pressure = 600 psi
- Pit volume gain = 35 bbl
- True vertical depth = 10,000 ft
Calculations

Drill string volume:

Drill pipe capacity 0.01776 bbl/ft x 9925 ft = 176.27 bbl
HWDP capacity 0.00883 bbl/ft x 240 ft = 2.12 bbl
Drill collar capacity 0.0087 bbl/ft x 360 ft = 3.13 bbl
Total drill string volume = 181.5 bbl

Annular volume:

Drill collar/open hole 0.0836 bbl/ft x 360 ft = 30.10 bbl
Drill pipe/open hole 0.1215 bbl/ft x 6165 ft = 749.05 bbl
Drill pipe/casing 0.1303 bbl/ft x 4000 ft = 521.20 bbl
Total annular volume = 1300.35 bbl

Strokes to bit: Drill string volume 181.5 bbl ÷ 0.136 bbl/stk = 1335 stk

Bit to casing strokes: Open hole volume = 779.15 bbl ÷ 0.136 bbl/stk = 5729 stk

Bit to surface strokes: Annular volume = 1300.35 bbl 0.136 bbl/stk = 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 x 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:
Formulas and Calculations

Pressure Chart

<table>
<thead>
<tr>
<th>Strokes</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>133.5</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>267</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>401</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>534</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>668</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>801</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>935</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>1068</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>1202</td>
</tr>
<tr>
<td>+ 133.5</td>
<td>1335</td>
</tr>
</tbody>
</table>

Pressure

ICP (1480) psi — FCP (1094) ÷ 10 = 38.6 psi

Therefore, the pressure will decrease by 38.6 psi per line.

Pressure Chart

<table>
<thead>
<tr>
<th>Strokes</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>1480</td>
</tr>
<tr>
<td>- 38.6</td>
<td>1441</td>
</tr>
<tr>
<td>- 38.6</td>
<td>1403</td>
</tr>
<tr>
<td>- 38.6</td>
<td>1364</td>
</tr>
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<td>- 38.6</td>
<td>1326</td>
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<td>- 38.6</td>
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<td>- 38.6</td>
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<td>- 38.6</td>
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<td>- 38.6</td>
<td>1171</td>
</tr>
<tr>
<td>- 38.6</td>
<td>1133</td>
</tr>
<tr>
<td>- 38.6</td>
<td>1094</td>
</tr>
</tbody>
</table>

Trip Margin (TM)

TM = Yield point ÷ 11.7(Dh, in. — Dp, in.)

Example: Yield point = 10 lb/100 sq ft; Dh = 8.5 in.; Dp = 4.5 in.

TM = 10 ÷ 11.7 (8.5 — 4.5)
TM = 0.2 ppg
**Determine Psi/stk**

\[
\text{psi/stk} = \frac{\text{ICP} - \text{FCP}}{\text{strokes to bit}}
\]

*Example:* Using the kill sheet just completed, adjust the pressure chart to read in increments that are easy to read on pressure gauges. Example: 50 psi:

**Data:**
- Initial circulating pressure = 1480 psi
- Final circulating pressure = 1094 psi
- Strokes to bit = 1335 psi

\[
\text{psi/stk} = \frac{1480 - 1094}{1335}
\]

\[
\text{psi/stk} = 0.2891
\]

The pressure side of the chart will be as follows:

**Pressure Chart**

<table>
<thead>
<tr>
<th>Strokes</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>1480</td>
</tr>
<tr>
<td></td>
<td>1450</td>
</tr>
<tr>
<td></td>
<td>1400</td>
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<tr>
<td></td>
<td>1100</td>
</tr>
<tr>
<td></td>
<td>1094</td>
</tr>
</tbody>
</table>

Adjust the strokes as necessary.

For line 2: How many strokes will be required to decrease the pressure from 1480 psi to 1450 psi?

1480 psi — 1450 psi = 30 psi

30 psi ÷ 0.2891 psi/stk = 104 strokes

For lines 3 to 7: How many strokes will be required to decrease the pressure by 50 psi increments?

Therefore, the new pressure chart will be as follows:
**Pressure Chart**

<table>
<thead>
<tr>
<th>Strokes</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>104</td>
<td>1480</td>
</tr>
<tr>
<td>104 + 173 =</td>
<td>1450</td>
</tr>
<tr>
<td>+ 173 =</td>
<td>1400</td>
</tr>
<tr>
<td>+ 173 =</td>
<td>1350</td>
</tr>
<tr>
<td>+ 173 =</td>
<td>1300</td>
</tr>
<tr>
<td>+ 173 =</td>
<td>1250</td>
</tr>
<tr>
<td>+ 173 =</td>
<td>1200</td>
</tr>
<tr>
<td>+ 173 =</td>
<td>1150</td>
</tr>
<tr>
<td>+ 173 =</td>
<td>1100</td>
</tr>
<tr>
<td>+ 173 =</td>
<td>1094</td>
</tr>
</tbody>
</table>

**Kill Sheet With a Tapered String**

\[
\text{psi @ _____ strokes} = \text{ICP} - \left[ \frac{\text{DPL}}{\text{DSL}} \times (\text{ICP} - \text{FCP}) \right]
\]

**Note:** Whenever a kick is taken with a tapered drill string in the hole, interim pressures should be calculated for a) the length of large drill pipe (DPL) and b) the length of large drill pipe plus the length of small drill pipe.

**Example:**
- Drill pipe 1: 5.0 in. 19.5 lb/ft Capacity = 0.01776 bbl/ft Length = 7000 ft
- Drill pipe 2: 3-1/2 in. 13.3 lb/ft Capacity = 0.0074 bbl/ft Length = 6000 ft
- Drill collars: 4 1/2 in. OD x 1-1/2 in. ID Capacity = 0.0022 bbl/ft Length = 2000 ft

**Step 1** Determine strokes:

- \(7000 \times 0.01776 \text{ bbl/ft} \div 0.117 \text{ bbl/stk} = 1063\)
- \(6000 \times 0.00742 \text{ bbl/ft} \div 0.117 \text{ bbl/stk} = 381\)
- \(2000 \times 0.0022 \text{ bbl/ft} \div 0.117 \text{ bbl/stk} = 38\)
- **Total strokes** = 1482

**Data from kill sheet**

Initial drill pipe circulating pressure (ICP) = 1780 psi
Final drill pipe circulating pressure (FCP) = 1067 psi

**Step 2** Determine interim pressure for the 5.0 in. drill pipe at 1063 strokes:

\[
\text{psi @ 1063 strokes} = 1780 - \left[ \frac{(7000 \div 15,000) \times (1780 - 1067)}{0.4666 \times 713} \right] = 1780 - 333 = 1447 \text{ psi}
\]
Step 3  Determine interim pressure for 5.0 in. plus 3-1/2 in. drill pipe
(1063 + 381) = 1444 strokes:

\[ \text{psi @ 1444 strokes} = 1780 - [(11,300 \div 15,000) \times (1780 - 1067)] \]
\[ = 1780 - (0.86666 \times 713) \]
\[ = 1780 - 618 \]
\[ = 1162 \text{ psi} \]

Step 4  Plot data on graph paper

![Figure 4-1. Data from kill sheet.](image)

Note. After pumping 1062 strokes, if a straight line would have been plotted, the well would have been underbalanced by 178 psi.

**Kill Sheet for a Highly Deviated Well**

Whenever a kick is taken in a highly deviated well, the circulating pressure can be excessive when the kill weight mud gets to the kick-off point (KOP). If the pressure is excessive, the pressure schedule should be divided into two sections: 1) from surface to KOP, and 2) from KOP to TD. The following calculations are used:

Determine strokes from surface to KOP:

\[ \text{Strokes} = \text{drill pipe capacity, bbl/ft} \times \text{measured depth to KOP, ft} \times \text{pump output, bbl/stk} \]
Determine strokes from KOP to TD:

\[
\text{Strokes} = \text{drill string capacity, bbl/ft} \times \text{measured depth to TD, ft} \times \text{pump output, bbl/stk}
\]

Kill weight mud:

\[
\text{KWM} = \frac{\text{SIDPP}}{0.052} \div \text{TVD} + \text{OMW}
\]

Initial circulating pressure:

\[
\text{ICP} = \text{SIDPP} + \text{KRP}
\]

Final circulating pressure:

\[
\text{FCP} = \text{KWM} \times \text{KRP} \div \text{OMW}
\]

Hydrostatic pressure increase from surface to KOP:

\[
\text{psi} = (\text{KWM} - \text{OMW}) \times 0.052 \times \text{TVD} @ \text{KOP}
\]

Friction pressure increase to KOP:

\[
\text{FP} = (\text{FCP} - \text{KRP}) \times \text{MD} @ \text{KOP} \div \text{MD} @ \text{TD}
\]

Circulating pressure when KWM gets to KOP:

\[
\text{CP} @ \text{KOP} = \text{ICP} - \text{HP increase to KOP} + \text{friction pressure increase, psi}
\]

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:

\[
\text{Strokes} = \frac{0.01776 \text{ bbl/ft} \times 5000 \text{ ft}}{0.136 \text{ bbl/stk}}
\]

Strokes = 653

Strokes from KOP to TD:

\[
\text{Strokes} = \frac{0.01776 \text{ bbl/ft} \times 10,000 \text{ ft}}{0.136 \text{ bbl/stk}}
\]

Strokes = 1306
Total strokes from surface to bit:

Surface to bit strokes = 653 + 1306  
Surface to bit strokes = 1959

Kill weight mud (KWM):

\[ \text{KWM} = 800 \text{ psi} \times 0.052 + 10,000 \text{ ft} + 9.6 \text{ ppg} \]
\[ \text{KWM} = 11.1 \text{ ppg} \]

Initial circulating pressure (ICP):

\[ \text{ICP} = 800 \text{ psi} + 600 \text{ psi} \]
\[ \text{ICP} = 1400 \text{ psi} \]

Final circulating pressure (FCP):

\[ \text{FCP} = 11.1 \text{ ppg} \times 600 \text{ psi} \pm 9.6 \text{ ppg} \]
\[ \text{FCP} = 694 \text{ psi} \]

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:

\[ \text{FP} = (694 - 600) \times 5000 \div 15,000 \]
\[ \text{FP} = 31 \text{ psi} \]

Circulating pressure when KWM gets to KOP:

\[ \text{CP} = 1400 - 390 + 31 \]
\[ \text{CP} = 1041 \text{ psi} \]

Compare this circulating pressure to the value obtained when using a regular kill sheet:

\[ \text{psi/stk} = 1400 - 694 + 1959 \]
\[ \text{psi/stk} = 0.36 \]

\[ 0.36 \text{ psi/stk} \times 653 \text{ strokes} = 235 \text{ psi} \]

\[ 1400 - 235 = 1165 \text{ psi} \]

Using a regular kill sheet, the circulating drill pipe pressure would be 1165 psi. The adjusted pressure chart would have 1041 psi on the drill pipe gauge. This represents 124 psi difference in pressure, which would also be observed on the annulus (casing) side. It is recommended that if the difference in pressure at the KOP is 100 psi or greater, then the adjusted pressure chart should be used to minimise the chances of losing circulation.
The chart below graphically illustrates the difference:

![Figure 4—2. Adjusted pressure chart.](image)

### 2. Pre-recorded Information

#### Maximum Anticipated Surface Pressure

Two methods are commonly used to determine maximum anticipated surface pressure:

**Method 1:** Use when assuming the maximum formation pressure is from TD:

**Step 1** Determine maximum formation pressure (FPmax):

\[
FP_{max} = (\text{maximum mud wt to be used, ppg} + \text{safety factor, ppg}) \times 0.052 \times (\text{total depth, ft})
\]

**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%.

\[
HP_{gas} = \text{gas gradient, psi/ft} \times \text{total depth, ft}
\]

**Step 3** Determine maximum anticipated surface pressure (MASP):

\[
MASP = FP_{max} - HP_{gas}
\]
Example: Proposed total depth = 12,000 ft
Maximum mud weight to be used in drilling well = 12.0 ppg
Safety factor = 4.0 ppg
Gas gradient = 0.12 psi/ft

Assume that 100% of mud is blown out of well.

**Step 1** Determine fracture pressure, psi:

\[ FP_{\text{max}} = (12.0 + 4.0) \times 0.052 \times 12,000 \text{ ft} \]
\[ FP_{\text{max}} = 9984 \text{ psi} \]

**Step 2**

\[ HP_{\text{gas}} = 0.12 \times 12,000 \text{ ft} \]
\[ HP_{\text{gas}} = 1440 \text{ psi} \]

**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**

Fracture pressure, psi = (estimated fracture + safety factor, ppg) \times 0.052 \times (casing shoe TVD, ft)

Note: A safety factor is added to ensure the formation fractures before BOP pressure rating is exceeded.

**Step 2** Determine the hydrostatic pressure of gas in the wellbore (HPgas):

\[ HP_{\text{gas}} = \text{gas gradient, psi/ft} \times \text{casing shoe TVD, ft} \]

**Step 3** Determine the maximum anticipated surface pressure (MASP), psi:

Example: Proposed casing setting depth = 4000 ft
Estimated fracture gradient = 14.2 ppg
Safety factor = 1.0 ppg
Gas gradient = 0.12 psi/ft

Assume 100% of mud is blown out of the hole.

**Step 1** Fracture pressure, psi = (14.2 + 1.0) \times 0.052 \times 4000 \text{ ft}
\[ \text{Fracture pressure, psi} = 3162 \text{ psi} \]

**Step 2**

\[ HP_{\text{gas}} = 0.12 \times 4000 \text{ ft} \]
\[ HP_{\text{gas}} = 480 \text{ psi} \]
Step 3  
MASP = 3162 — 480  
MASP = 2682 psi

Sizing Diverter Lines

Determine diverter line inside diameter, in., equal to the area between the inside diameter of the casing and the outside diameter of drill pipe in use:

Diverter line ID, in. = $\sqrt{\text{lb} \cdot \text{bp}^2}$

Drill pipe — 19.5 lb/ft OD = 5.0 in.

Determine the diverter line inside diameter that will equal the area between the casing and drill pipe:

Diverter line ID, in. = $\sqrt{12.515^2 - 5.0^2}$  
Diverter line ID = 11.47 in.

Formation Pressure Tests

Two methods of testing:  
• Equivalent mud weight test  
• Leak-off test

Precautions to be undertaken before testing:

1. Circulate and condition the mud to ensure the mud weight is consistent throughout the system.
2. Change the pressure gauge (if possible) to a smaller increment gauge so a more accurate measure can be determined.
3. Shut-in the well.
4. Begin pumping at a very slow rate — 1/4 to 1/2 bbl/min.
5. Monitor pressure, time, and barrels pumped.
6. Some operators may have 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 is achieved or until 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 = 11.5 ppg + 1.0 ppg
Equivalent test mud weight = 12.5 ppg

**Method 2:** Subtract a value from the estimated fracture gradient for the depth of the casing shoe.

Equivalent test mud weight = (estimated fracture gradient, ppg) — (safety factor)

*Example:* Estimated formation fracture gradient = 14.2 ppg. Safety factor = 1.0 ppg

Equivalent test mud weight = 14.2 ppg — 1.0 ppg

Determine surface pressure to be used:

Surface pressure, psi = (equiv. Test — mud wt, ppg) x 0.052 x (casing seat, TVD ft)

*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) x 0.052 x 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.

Estimated leak-off pressure = (estimated fracture — mud wt, ppg) x 0.052 x (casing shoe, TVD, ft)
**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) x 0.052 x 4000 ft  
Estimated leak-off pressure = 4.8 x 0.052 x 4000  
Estimated leak-off pressure = 998 psi

**Maximum Allowable Mud Weight From Leak-off Test Data**

Max allowable mud weight, ppg = (leak off pressure, psi) ÷ 0.052 ÷ (casing shoe) + (mud wt in use, ppg) ÷ (TVD, ft )

**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):

MASICP = (maximum allowable — mud wt in use, ppg) x 0.052 x (casing shoe TVD, ft) ÷ (mud wt, ppg) 

**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) x 0.052 x 4000 ft  
MASICP = 582 psi

**Kick Tolerance Factor (KTF)**

KTF = Casing shoe TVD, ft ÷ well depth x (maximum allowable mud wt, ppg — mud wt in use, ppg)

**Example:** Determine the kick tolerance factor (KTF) using the following data:

- Mud weight in use = 10.0 ppg  
- Casing shoe TVD = 4000 ft  
- Well depth TVD = 10,000 ft  
- Maximum allowable mud weight (from leak-off test data) = 14.2 ppg
KTF = (4000 ft ÷ 10,000 ft) x (14.2 ppg — 10.0 ppg)
KTF = 1.68 ppg

**Maximum Surface Pressure From Kick Tolerance Data**

Maximum surface pressure = kick tolerance factor, ppg x 0.052 x TYD, ft

*Example:* Determine the maximum surface pressure, psi, using the following data:

Maximum surface pressure = 1.68 ppg x 0.052 x 10,000 ft
Maximum surface pressure = 874 psi

**Maximum Formation Pressure (FP) That Can be Controlled When Shutting-in a Well**

Maximum FP, psi = (kick tolerance factor, ppg + mud wt in use, ppg) x 0.052 x TYD, ft

*Example:* Determine the maximum formation pressure (FP) that can be controlled when shutting-in a well using the following data:

Data: Kick tolerance factor = 1.68 ppg  Mud weight = 10.0 ppg
True vertical depth = 10,000 ft

Maximum FP = (1.68 ppg + 10.0 ppg) x 0.052 x 10,000 ft
Maximum FP = 6074 psi

**Maximum Influx Height Possible to Equal Maximum Allowable Shut-in Casing Pressure (MASICP)**

Influx height = MASICP, psi ÷ (gradient of mud wt in use, psi/ft — influx gradient, psi/ft)

*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 x 0.052) = 0.52 psi/ft
Gradient of influx = 0.12 psi/ft

Influx height = 874 psi ÷ (0.52 psi/ft — 0.12 psi/ft)
Influx height = 2185 ft
**Maximum Influx, Barrels to Equal Maximum Allowable Shut-in Casing Pressure (MASICP)**

*Example:* Maximum influx height to equal MASICP (from above example) = 2185 ft  
Annular capacity — drill collars/open hole (12-1/4 in. x 8.0 in.) = 0.0826 bbl/ft  
Annular capacity — drill pipe/open hole (12-1/4 in. x 5.0 in.) = 0.1215 bbl/ft  
Drill collar length = 500 ft

**Step 1** Determine the number of barrels opposite drill collars:

Barrels = 0.0836 bbl/ft x 500 ft  
Barrels = 41.8

**Step 2** Determine the number of barrels opposite drill pipe:

Influx height, ft, opposite drill pipe:  
\[ \text{ft} = 2185 \text{ ft} - 500 \text{ ft} \]  
\[ \text{ft} = 1685 \]

Barrels opposite drill pipe:  
Barrels = 1685 ft x 0.1215 bbl/ft  
Barrels = 204.7

**Step 3** Determine maximum influx, bbl, to equal maximum allowable shut-in casing pressure:

Maximum influx = 41.8 bbl + 204.7 bbl  
Maximum influx = 246.5 bbl

**Adjusting Maximum Allowable Shut-in Casing Pressure For an Increase in Mud Weight**

MASICP = \( P_L - [D \times (\text{mud wt}_2 - \text{mud wt}_1)] \times 0.052 \)

where  
MASICP = maximum allowable shut-in casing (annulus) pressure, psi  
\( P_L \) = leak-off pressure, psi  
D = true vertical depth to casing shoe, ft  
\( \text{Mud wt}_2 \) = new mud wt, ppg  
\( \text{Mud wt}_1 \) = original mud wt, ppg

*Example:* Leak-off pressure at casing setting depth (TVD) of 4000 ft was 1040 psi with 10.0 ppg in use. Determine the maximum allowable shut-in casing pressure with a mud weight of 12.5 ppg:

MASICP = 1040 psi — [4000 x (12.5 — 10.0) 0.052]  
MASICP = 1040 psi — 520  
MASICP = 520 psi
3. **Kick Analysis**

**Formation Pressure (FP) With the Well Shut-in on a Kick**

\[ FP, \text{ psi} = \text{SIDPP, psi} + (\text{mud wt, ppg} \times 0.052 \times \text{TVD, ft}) \]

*Example:* Determine the formation pressure using the following data:

- Shut-in drill pipe pressure: 500 psi
- Mud weight in drill pipe: 9.6 ppg
- True vertical depth: 10,000 ft

\[ FP, \text{ psi} = 500 \text{ psi} + (9.6 \text{ ppg} \times 0.052 \times 10,000 \text{ ft}) \]
\[ FP, \text{ psi} = 500 \text{ psi} + 4992 \text{ psi} \]
\[ FP = 5492 \text{ psi} \]

**Bottom hole Pressure (BHP) With the Well Shut-in on a Kick**

\[ BHP, \text{ psi} = \text{SIDPP, psi} + (\text{mud wt, ppg} \times 0.052 \times \text{TVD, ft}) \]

*Example:* Determine the bottom hole 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

\[ BHP, \text{ psi} = 500 \text{ psi} + (9.6 \text{ ppg} \times 0.052 \times 10,000 \text{ ft}) \]
\[ BHP, \text{ psi} = 500 \text{ psi} + 4992 \text{ psi} \]
\[ BHP = 5492 \text{ psi} \]

**Shut-in Drill Pipe Pressure (SIDPP)**

\[ \text{SIDPP, psi} = \text{formation pressure, psi} - (\text{mud wt, ppg} \times 0.052 \times \text{TVD, ft}) \]

*Example:* Determine the shut-in drill pipe pressure using the following data:

- Formation pressure: 12,480 psi
- Mud weight in drill pipe: 15.0 ppg
- True vertical depth: 15,000 ft

\[ \text{SIDPP, psi} = 12,480 \text{ psi} - (15.0 \text{ ppg} \times 0.052 \times 15,000 \text{ ft}) \]
\[ \text{SIDPP, psi} = 12,480 \text{ psi} - 11,700 \text{ psi} \]
\[ \text{SIDPP} = 780 \text{ psi} \]
**Shut-in Casing Pressure (SICP)**

SICP = (formation pressure, psi) — (HP of mud in annulus, psi + HP of influx in annulus, psi)

*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

\[
\text{SICP, psi} = 12,480 - [(15.0 \times 0.052 \times 14,600) + (0.12 \times 400)] \\
\text{SICP, psi} = 12,480 - 11,388 + 48 \\
\text{SICP} = 1044 \text{ psi}
\]

**Height, \( Fl \), of Influx**

Height of influx, ft = pit gain, bbl ÷ annular capacity, bbl/ft

*Example 1:* Determine the height, ft, of the influx using the following data:

- Pit gain : 20 bbl
- Annular capacity — DC/OH = 0.02914 bbl/ft
  
  \((Dh = 8.5 \text{ in.} — Dp = 6.5)\)

\[
\text{Height of influx, ft} = 20 \text{ bbl} ÷ 0.02914 \text{ bbl/ft} \\
\text{Height of influx} = 686 \text{ ft}
\]

*Example 2:* Determine the height, ft, of the influx using the following data:

- Pit gain : 20 bbl
- Hole size = 8.5 in.
- Drill size = 8.5 in.
- Drill collar length = 450 ft

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 x annular capacity
- Barrels = 450 ft x 0.02914 bbl/ft
- Barrels = 13.1

Determine annular capacity, bbl/ft, opposite drill pipe:

\[
\text{Annular capacity, bbl/ft} = \frac{8.5^2 - 5.0^2}{1029.4} \\
\text{Annular capacity} = 0.0459 \text{ bbl/ft}
\]
Determine barrels of influx opposite drill pipe:

Barrels = pit gain, bbl — barrels opposite drill collars
Barrels = 20 bbl — 13.1 bbl
Barrels = 6.9

Determine height of influx opposite drill pipe:

Height, ft = 6.9 bbl : 0.0459 bbl/ft
Height = 150 ft

Determine the total height of the influx:

Height, ft = 450 ft + 150 ft
Height = 600 ft

**Estimated Type of Influx**

Influx weight, ppg = mud wt, ppg — ((SICP — SIDPP) ÷ height of influx, ft x 0.052)

then: 1 — 3 ppg = gas kick
4 — 6 ppg = oil kick or combination
7 — 9 ppg = saltwater kick

Example: Determine the type of the influx using the following data:

<table>
<thead>
<tr>
<th>Shut-in casing pressure</th>
<th>1044 psi</th>
<th>Height of influx</th>
<th>400 ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shut-in drill pipe pressure</td>
<td>780 psi</td>
<td>Mud weight</td>
<td>15.0 ppg</td>
</tr>
</tbody>
</table>

Influx weight, ppg = 15.0 ppg — ((1044 — 780) ÷ 400 x 0.052)
Influx weight, ppg = 15.0 ppg — 264
Influx weight = 2.31 ppg

Therefore, the influx is probably “gas.”

**Gas Migration in a Shut-in Well**

Estimating the rate of gas migration, ft/hr:

\[ V_g = 12e^{(-0.37)(\text{mud wt. ppg})} \]

\[ V_g = \text{rate of gas migration, ft/hr} \]

Example: Determine the estimated rate of gas migration using a mud weight of 11.0 ppg:

\[ V_g = 12e^{(-0.37)(11.0 \text{ ppg})} \]

\[ V_g = 12e^{(-4.07)} \]

\[ V_g = 0.205 \text{ ft/sec} \]

\[ V_g = 0.205 \text{ ft/sec} \times 60 \text{ sec/min} \]

\[ V_g = 12.3 \text{ ft/min} \times 60 \text{ min/hr} \]

\[ V_g = 738 \text{ ft/hr} \]
Determining the actual rate of gas migration after a well has been shut-in on a kick:

Rate of gas migration, ft/hr = \frac{\text{increase in casing pressure, psi/hr}}{\text{pressure gradient of mud weight in use, psi/ft}}

Example: Determine the rate of gas migration with the following data:

Stabilised shut-in casing pressure = 500 psi  SICP after one hour = 700 psi
Pressure gradient for 12.0 ppg mud = 0.624 psi/ft  Mud weight = 12.0 ppg

Rate of gas migration, ft/hr = 200 psi/hr ÷ 0.624 psi/ft
Rate of gas migration = 320.5 ft/hr

Hydrostatic Pressure Decrease at TD Caused by Gas Cut Mud

Method 1:

HP decrease, psi = \frac{100 \times (\text{weight of uncut mud, ppg} - \text{weight of gas cut mud, ppg})}{\text{weight of gas cut mud, ppg}}

Example: Determine the hydrostatic pressure decrease mud using the following data:

Weight of uncut mud = 18.0 ppg  Weight of gas cut mud = 9.0 ppg

HP decrease, psi = \frac{100 \times (18.0 \text{ ppg} - 9.0 \text{ ppg})}{9.0 \text{ ppg}}

HP Decrease = 100 psi

Method 2: \[ P = \frac{\text{MG} \times \text{V}}{\text{C}} \]

where \( P \) = reduction in bottomhole pressure, psi  \( \text{MG} \) = mud gradient, psi/ft
\( \text{C} \) = annular volume, bbl/ft  \( \text{V} \) = pit gain, bbl

Example: \( \text{MG} = 0.624 \text{ psi/ft} \)
\( \text{C} = 0.0459 \text{ bbl/ft} \) (\( \text{Dh} = 8.5 \text{ in.}; \text{Dp} = 5.0 \text{ in.} \))
\( \text{V} = 20 \text{ bbl} \)

Solution: \( P = \frac{0.624 \text{ psi/ft} \times 0.0459 \text{ bbl/ft}}{20} \times 20 \)
\( P = 13.59 \times 20 \)
\( P = 271.9 \text{ psi} \)

Maximum Surface Pressure From a Gas Kick in a Water Base Mud

\[ \text{MSPgk} = 0.2 \sqrt{\frac{\text{P} \times \text{V} \times \text{KWM}}{\text{C}}} \]

where MSPgk = maximum surface pressure resulting from a gas kick in a water base mud
\( \text{P} \) = formation pressure, psi  \( \text{V} \) = pit gain, bbl
\( \text{KWM} \) = kill weight mud, ppg  \( \text{C} \) = annular capacity, bbl/ft
Example: \( P = 12,480 \text{ psi} \quad V = 20 \text{ bbl} \quad KWM = 16.0 \text{ ppg} \quad C = 0.0505 \text{ bbl/ft (Dh = 8.5 in. x Dp = 4.5 in.)} \)

Solution: \( MSPgk = 0.2 \sqrt[4]{12,480 \times 20 \times 16.0} \)

\( MSPgk = 0.2 \sqrt[4]{790,811.88} \)

\( MSPgk = 0.2 \times 8892.76 \)

\( MSPgk = 1779 \text{ psi} \)

**Maximum Pit Gain From Gas Kick in a Water Base Mud**

\( MPGgk = 4 \sqrt{\frac{P \times V \times C}{KWM}} \)

where \( MPGgk \) = maximum pit gain resulting from a gas kick in a water base mud

\( P \) = formation pressure, psi

\( V \) = original pit gain, bbl

\( C \) = annular capacity, bbl/ft

\( KWM \) = kill weight mud, ppg

Example: \( P = 12,480 \text{ psi} \quad V = 20 \text{ bbl} \quad C = 0.0505 \text{ bbl/ft (8.5 in. x 4.5 in.)} \)

Solution: \( MPGgk = 4 \sqrt{\frac{12,480 \times 20 \times 0.0505}{16.0}} \)

\( MPGgk = 4 \times 28.06 \)

\( MPGgk = 112.3 \text{ bbl} \)

**Maximum Pressures When Circulating Out a Kick (Moore Equations)**

The following equations will be used:

1. Determine formation pressure, psi: \( Pb = \text{SIDP} + (\text{mud wt, ppg x 0.052 x TVD, ft}) \)
2. Determine the height of the influx, ft: \( hi = \text{pit gain, bbl} \div \text{annular capacity, bbl/ft} \)
3. Determine pressure exerted by the influx, psi: \( Pi = Pb — [Pm (D — X) + SICP] \)
4. Determine gradient of influx, psi/ft: \( Ci = Pi \div hi \)
5. Determine Temperature, °R, at depth of interest: \( Tdi = 70°F + (0.012°F/ft \cdot Di) + 460 \)
6. Determine A for unweighted mud: \( A = Pb — [Pm (D — X) — Pi] \)
7. Determine pressure at depth of interest: \( Pdi = A + (\frac{A^2 + pm \ Pb Zdi \ T°Rdi \ hi}{2 \ 4 \ Zb \ Tb})^{1/2} \)
8. Determine kill weight mud, ppg: \( KWM, \text{ ppg} = \text{SIDPP} \div 0.052 \div \text{TVD, ft + 0MW, ppg} \)
9. Determine gradient of kill weight mud, psi/ft: \( p_{\text{KWM}} = K_{\text{WM}}, \text{ppg} \times 0.052 \)

10. Determine FEET that drill string volume will occupy in the annulus:

\[
\text{Di} = \frac{\text{drill string vol}, \text{bbl}}{\text{annular capacity}, \text{bbl/ft}}
\]

11. Determine \( A \) for weighted mud:

\[
A = \text{Pb} - \left[ \text{p}_m (D - X) - \text{Pi} \right] + \left[ \text{Di} (p_{\text{KWM}} - \text{p}_m) \right]
\]

**Example:**

Assumed conditions:

- Well depth = 10,000 ft
- Hole size = 8.5 in.
- Surface casing = 9-5/8 in. @ 2500 ft
- Casing ID = 8.921 in.
- Fracture gradient @ 2500 ft = 0.73 psi/ft (14.04 ppg)
- Casing ID capacity = 0.077 bbl/ft
- Drill pipe = 4.5 in. — 16.6 lb/ft
- Drill collar OD = 6-1/4 in.
- Drill collar OD length = 625 ft
- Mud weight = 9.6 ppg

Mud volumes:

- 8-1/2 in. hole = 0.07 bbl/ft
- 8.921 in. casing x 4-1/2 in. drill pipe = 0.057 bbl/ft
- Drill pipe capacity = 0.014 bbl/ft
- 8-1/2 in. hole x 6-1/4 in. drill collars = 0.032 bbl/ft
- Drill collar capacity = 0.007 bbl/ft
- 8-1/2 in. hole x 4-1/2 in. drill pipe = 0.05 bbl/ft
- Super compressibility 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:

\[
P_b = 260 \text{ psi} + (9.6 \text{ ppg} \times 0.052 \times 10,000 \text{ ft})
\]

\[
P_b = 5252 \text{ psi}
\]

2. Determine height of influx at TD:

\[
h_i = 20 \text{ bbl} \div 0.032 \text{ bbl/ft}
\]

\[
h_i = 625 \text{ ft}
\]

3. Determine pressure exerted by influx at TD:

\[
P_i = 5252 \text{ psi} - [0.4992 \text{ psi/ft} (10,000 - 625) + 500]
\]

\[
P_i = 5252 \text{ psi} - [4680 \text{ psi} + 500]
\]

\[
P_i = 5252 \text{ psi} - 5180 \text{ psi}
\]

\[
P_i = 72 \text{ psi}
\]
4. Determine gradient of influx at TD:

\[ Ci = \frac{72 \text{ psi}}{625 \text{ ft}} = 0.1152 \text{ psi/ft} \]

5. Determine height and pressure of influx around drill pipe:

\[ h = \frac{20 \text{ bbl}}{0.05 \text{ bbl/ft}} = 400 \text{ ft} \]

\[ Pi = 0.1152 \text{ psi/ft} \times 400 \text{ ft} = 46 \text{ psi} \]

6. Determine T °R at TD and at shoe:

\[ T^\circ \text{R} @ 10,000 \text{ ft} = 70 + (0.012 \times 10,000) + 460 = 70 + 120 + 460 = 650 \text{ °R} \]

\[ T^\circ \text{R} @ 2500 \text{ ft} = 70 + (0.012 \times 2500) + 460 = 70 + 30 + 460 = 560 \text{ °R} \]

7. Determine A:

\[ A = 5252 \text{ psi} - [0.4992 (10,000 - 2500) + 46] \]

\[ A = 5252 \text{ psi} - (3744 - 46) = 1462 \text{ psi} \]

8. Determine maximum pressure at shoe with drillers method:

\[ P_{2500} = \frac{1462 + [1462^2 (0.4992)(5252)(1)(560)(400)]^{1/2}}{2} \]

\[ = \frac{731 + (534361 + 903512)^{1/2}}{2} = \frac{1199}{2} = 599.5 \text{ psi} \]

Determine maximum pressure at surface with drillers method:

1. Determine A:

\[ A = 5252 - [0.4992 (10,000) + 46] \]

\[ A = 5252 - (4992 + 46) = 214 \text{ psi} \]

2. Determine maximum pressure at surface with drillers method:

\[ P_s = \frac{214 + [214^2 (0.4992)(5252)(1)(530)(400)]^{1/2}}{2} \]

\[ = \frac{107 + (11449 + 855109)^{1/2}}{2} = \frac{107 + 931}{2} = 519 \text{ psi} \]
Determine maximum pressure at shoe with wait and weight method:

1. Determine kill weight mud:

\[ \text{KWM, ppg} = \frac{260 \text{ psi}}{0.052 \div 10,000 \text{ ft}} + 9.6 \text{ ppg} \]
\[ \text{KWM, ppg} = 10.1 \text{ ppg} \]

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:

\[ \text{Drill pipe vol} = 0.014 \text{ bbl/ft} \times 9375 \text{ ft} = 131.25 \text{ bbl} \]
\[ \text{Drill collar vol} = 0.007 \text{ bbl/ft} \times 625 \text{ ft} = 4.375 \text{ bbl} \]
\[ \text{Total drill string volume} = 135.625 \text{ bbl} \]

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:

\[ A = 5252 - [0.5252(10,000 - 2500) - 46] + (2715.2(0.5252 - 0.4992)) \]
\[ A = 5252 - (3939 - 46) + 70.6 \]
\[ A = 1337.5 \]

6. Determine maximum pressure at shoe with wait and weight method:

\[ P_{2500} = \frac{1337.5 + [\frac{1337.5^2}{2} + (0.5252)(5252)(1)(560)(400)]^{1/2}}{4} \]
\[ = 668.75 + (447226 + 950569.98)^{1/2} \]
\[ = 668.75 + 1182.28 \]
\[ = 1851 \text{ psi} \]

Determine maximum pressure at surface with wait and weight method:

1. Determine A:

\[ A = 5252 - [0.5252(10,000 - 46)] + [2712.5(0.5252 - 0.4992)] \]
\[ A = 5252 - (5252 - 46) + 70.525 \]
\[ A = 24.5 \]

2. Determine maximum pressure at surface with wait and weight method:

\[ P_s = \frac{12.25 + [\frac{24.5^2}{2} + (0.5252)(5252)(1)(560)(400)]^{1/2}}{(650)} \]
Ps = 12.25 + (150.0625 + 95069.98)^(1/2)
Ps = 12.25 + 975.049
Ps = 987 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
MW = mud weight, ppg
Pdi = pressure at depth of interest, psi
Pi = pressure exerted by influx, psi
pm = pressure gradient of mud weight in use, ppg
psihi = height of influx, ft
Pb = formation pressure, psi
pKWM = pressure gradient of kill weight mud, ppg
Ps = pressure at surface, psi
SIDP = shut-in drill pipe pressure, psi
SICP, = shut-in casing pressure,
T°F = temperature, degrees Fahrenheit, at depth of interest
T°R = temperature, degrees Rankine, at depth of interest
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 x md x Dp x L ÷ U x ln(Re ÷ Rw) x 1440

Q = 0.007 x 200 x 624 x 20 ÷ 0.3 x 2.0 x 1440
Q = 20 bbl/min

Therefore: If one minute is required to shut-in the well, a pit gain of 20 bbl occurs in addition to the gain incurred while drilling the 20-ft section.
4. Pressure Analysis

Gas Expansion Equations

Basic gas laws: \[ P_1 V_1 + T_1 = P_2 V_2 + T_2 \]

where \( P_1 \) = formation pressure, psi
\( P_2 \) = hydrostatic pressure at the surface or any depth in the wellbore, psi
\( V_1 \) = original pit gain, bbl
\( V_2 \) = gas volume at surface or at any depth of interest, bbl
\( T_1 \) = temperature of formation fluid, degrees Rankine \( (^\circ R = ^\circ F + 460) \)
\( T_2 \) = temperature at surface or at any depth of interest, degrees Rankine

Basic gas law plus compressibility factor: \[ P_1 V_1 + T_1 Z_1 = P_2 V_2 + T_2 Z_2 \]

where \( Z_1 \) = compressibility factor under pressure in formation, dimensionless
\( Z_2 \) = compressibility factor at the surface or at any depth of interest, dimensionless

Shortened gas expansion equation: \[ P_3 V_1 = P, V_2 \]

where \( P_1 \) = formation pressure, psi
\( P_2 \) = hydrostatic pressure plus atmospheric pressure (14.7 psi), psi
\( V_1 \) = original pit gain, bbl
\( V_2 \) = gas volume at surface or at any depth of interest, bbl

Hydrostatic Pressure Exerts by Each Barrel of Mud in the Casing

With pipe in the wellbore:

\[
\text{psi/bbl} = \frac{1029.4 \times 0.052 \times \text{mud wt, ppg}}{D_h^2 - D_p^2}
\]

Example: \( D_h = 9-5/8 \text{ in, casing} - 43.5 \text{ lb/ft} = 8.755 \text{ in. ID} \quad D_p = 5.0 \text{ in. OD} \)
\[
\text{Mud weight} = 10.5 \text{ ppg}
\]

\[
\text{psi/bbl} = \frac{1029.4 \times 0.052 \times 10.5 \text{ ppg}}{8.755^2 - 5.0^2}
\]

\[
\text{psi/bbl} = 19.93029 \times 0.052 \times 10.5 \text{ ppg}
\]

\[
\text{psi/bbl} = 10.88
\]

With no pipe in the wellbore:

\[
\text{psi/bbl} = \frac{1029.4 \times 0.052 \times \text{mud wt ppg}}{\text{ID}^2}
\]
Example: Dh — 9-5/8 in. casing — 43.5 lb/ft = 8.755 in. ID  Mud weight = 10.5 ppg

\[
\text{psi/bbl} = \frac{1029.4 \times 0.052 \times 10.5 \text{ ppg}}{8.755^2}
\]

\[
\text{psi/bbl} = 13.429872 \times 0.052 \times 10.5 \text{ ppg}
\]

\[
\text{psi/bbl} = 7.33
\]

**Surface Pressure During Drill Stem Tests**

Determine formation pressure:

\[\text{psi} = \text{formation pressure equivalent mud wt, ppg} \times 0.052 \times \text{TVD, ft}\]

Determine oil hydrostatic pressure:

\[\text{psi} = \text{oil specific gravity} \times 0.052 \times \text{TVD, ft}\]

Determine surface pressure:

\[\text{Surface pressure, psi} = \text{formation pressure, psi} - \text{oil hydrostatic pressure, psi}\]

*Example: Oil bearing sand at 12,500 ft with a formation pressure equivalent to 13.5 ppg. If the specific gravity of the oil is 0.5, what will be the static surface pressure during a drill stem test?*

Determine formation pressure, psi:

\[\text{FP, psi} = 13.5 \text{ ppg} \times 0.052 \times 12,500 \text{ ft}\]

\[\text{FP} = 8775 \text{ psi}\]

Determine oil hydrostatic pressure:

\[\text{psi} = (0.5 \times 8.33) \times 0.052 \times 12,500 \text{ ft}\]

\[\text{psi} = 2707\]

Determine surface pressure:

\[\text{Surface pressure, psi} = 8775 \text{ psi} - 2707 \text{ psi}\]

\[\text{Surface pressure} = 6068 \text{ psi}\]
5. Stripping/Snubbing Calculations

Breakover Point Between Stripping and Snubbing

*Example:* Use the following data to determine the breakover point:

**DATA:**
- Mud weight = 12.5 ppg
- Drill collars (6-1/4 in.— 2-13/16 in.) = 83 lb/ft
- Length of drill collars = 276 ft
- Drill pipe = 5.0 in.
- Drill pipe weight = 19.5 lb/ft
- Shut-in casing pressure = 2400 psi
- Buoyancy factor = 0.8092

Determine the force, lb, created by wellbore pressure on 6-1/4 in. drill collars:

\[
\text{Force, lb} = (\text{pipe or collar OD, In.)}^2 \times 0.7854 \times (\text{wellbore pressure, psi})
\]

\[
\text{Force, lb} = 6.252 \times 0.7854 \times 2400 \text{ psi}
\]

\[
\text{Force} = 73,631 \text{ lb}
\]

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:

\[
\text{Drill pipe weight, lb} = \text{force created by wellbore pressure, lb} - \text{drill collar weight, lb}
\]

\[
\text{Drill pipe weight, lb} = 73,631 \text{ lb} - 18,537 \text{ lb}
\]

\[
\text{Drill pipe weight, lb} = 55,094 \text{ lb}
\]

Length of drill pipe required to reach breakover point:

\[
\text{Drill pipe} = (\text{required drill pipe weight, lb}) \div (\text{drill pipe weight, lb/ft x factor buoyancy})
\]

\[
\text{Drill pipe length, ft} = 55,094 \text{ lb} \div (19.5 \text{ lb/ft} \times 0.8092)
\]

\[
\text{Drill pipe length, ft} = 3492 \text{ ft}
\]

Length of drill string to reach breakover point:

\[
\text{Drill string length, ft} = \text{drill collar length, ft} + \text{drill pipe length, ft}
\]

\[
\text{Drill string length, ft} = 276 \text{ ft} + 3492 \text{ ft}
\]

\[
\text{Drill string length} = 3768 \text{ ft}
\]
Minimum Surface Pressure Before Stripping is Possible

Minimum surface \( = \frac{(\text{weight of one stand of collars, lb})}{(\text{area of drill collars, sq in.})} \) pressure, psi

Example: Drill collars — 8.0 in. OD x 3.0 in. ID = 147 lb/ft Length of one stand 92 ft

Minimum surface pressure, psi = \( \frac{(147 \text{ lb/ft x 92 ft})}{(8^2 \times 0.7854)} \)
Minimum surface pressure, psi = 13,524 ÷ 50.2656 sq in.
Minimum surface pressure = 269 psi

Height Gain From Stripping into Influx

Height, ft = \( \frac{L (C_{dp} + D_{dp})}{C_a} \)

where \( L \) = length of pipe stripped, ft
\( C_{dp} \) = capacity of drill pipe, drill collars, or tubing, bbl/ft
\( D_{dp} \) = displacement of drill pipe, drill collars or tubing, bbl/ft
\( C_a \) = annular capacity, bbl/ft

Example: If 300 ft of 5.0 in. drill pipe — 19.5 lb/ft is stripped into an influx in a 12-1/4 in. hole, determine the height, ft, gained:

DATA: Drill pipe capacity = 0.01776 bbl/ft Length drill pipe stripped = 300 ft
Drill pipe displacement = 0.00755 bbl/ft Annular capacity = 0.1215 bbl/ft

Solution: Height, ft = \( \frac{300 (0.01776 + 0.00755)}{0.1215} \)
Height = 62.5 ft

Casing Pressure Increase From Stripping Into Influx

\( \text{psi} = (\text{gain in height, ft}) \times (\text{gradient of mud, psi/ft} — \text{gradient of influx, psi/ft}) \)

Example: Gain in height = 62.5 ft
Gradient of mud (12.5 ppg x 0.052) = 0.65 psi/ft
Gradient of influx = 0.12 psi/ft

\( \text{psi} = 62.5 \text{ ft x (0.65 — 0.12)} \)
\( \text{psi} = 33 \text{ psi} \)

Volume of Mud to Bleed to Maintain Constant Bottomhole Pressure with a Gas Bubble Rising

With pipe in the hole: \( V_{mud} = \frac{D_p \times C_a}{\text{gradient of mud, psi/ft}} \)
where \( V_{mud} \) = volume of mud, bbl, that must be bled to maintain constant bottomhole pressure with a gas bubble rising.

- \( D_p \) = incremental pressure steps that the casing pressure will be allowed to increase.
- \( C_a \) = annular capacity, bbl/ft

**Example:**
Casing pressure increase per step \( = 100 \) psi
Gradient of mud \( (13.5 \text{ ppg} \times 0.052) \) \( = 0.70 \text{ psi/ft} \)
Annular capacity \( (D_h = 12-1/4 \text{ in.}; D_p = 5.0 \text{ in.}) \) \( = 0.1215 \text{ bbl/ft} \)

\[
V_{mud} = \frac{100 \text{ psi} \times 0.1215 \text{ bbl/ft}}{0.702 \text{ psi/ft}}
\]

\( V_{mud} = 17.3 \text{ bbl} \)

With no pipe in hole:
\[
V_{mud} = \frac{D_p \times C_h}{\text{gradient of mud, psi/ft}}
\]

**Example:**
Casing pressure increase per step \( = 100 \) psi
Gradient of mud \( (13.5 \text{ ppg} \times 0.052) \) \( = 0.702 \text{ psi/ft} \)
Hole capacity \( (12-1/4 \text{ in.}) \) \( = 0.1458 \text{ bbl/ft} \)

\[
V_{mud} = \frac{100 \text{ psi} \times 0.1458 \text{ bbl/ft}}{0.702 \text{ psi/ft}}
\]

\( V_{mud} = 20.77 \text{ bbl} \)

**Maximum Allowable Surface Pressure (MASP) Governed by the Formation**

\[
\text{MASP, psi} = (\text{maximum allowable — mud wt, in use,}) \times 0.052 \times \text{casing shoe TVD, ft}
\]

**Example:**
Maximum allowable mud weight \( = 15.0 \text{ ppg} \) (from leak-off test data)
Mud weight \( = 12.0 \text{ ppg} \)
Casing seat TVD \( = 8000 \text{ ft} \)

\[
\text{MASP} = (15.0 — 12.0) \times 0.052 \times 8000
\]

\( \text{MASP} = 1248 \text{ psi} \)

**Maximum Allowable Surface Pressure (MASP) Governed by Casing Burst Pressure**

\[
\text{MASP} = (\text{casing burst pressure x safety factor}) — (\text{mud wt in use — mud wt outside}) \times 0.052 \times \text{casing, shoe TVD ft}
\]

**Example:**
Casing — 10-3/4 in. — 51 lb/ft N-80
Mud weight behind casing \( = 9.4 \text{ ppg} \)
Casing setting depth \( = 8000 \text{ ft} \)

\[
\text{MASP} = (6070 \times 80%) — [(12.0 — 9.4) \times 0.052 \times 8000]
\]

\( \text{MASP} = 3774 \text{ psi} \)
6. **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):

Reduced casing pressure, psi = (shut-in casing pressure, psi) — (choke line pressure loss, psi)

*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 a straight line effect. While bringing the well on choke, to maintain a constant bottomhole pressure, the following chart should be used:

<table>
<thead>
<tr>
<th>Line</th>
<th>Strokes</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>3</td>
<td>38</td>
<td>38</td>
</tr>
<tr>
<td>4</td>
<td>44</td>
<td>44</td>
</tr>
<tr>
<td>5</td>
<td>50</td>
<td>50</td>
</tr>
</tbody>
</table>

Strokes side: Example: kill rate speed = 50 spm

Pressure side: Example. Shut-in casing pressure (SICP) = 800 psi
Choke line pressure loss (CLPL) = 300 psi

Divide choke line pressure loss (CLPL) by 4, because there are 4 steps on the chart:

\[
\text{psi/line} = \frac{(\text{CLPL})}{4} = 75 \text{ psi}
\]

<table>
<thead>
<tr>
<th>Line</th>
<th>Strokes</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>725</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>650</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>575</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>500</td>
<td></td>
</tr>
</tbody>
</table>
Maximum Allowable Mud Weight, ppg, Subsea Stack as Derived from Leak-off Test Data

Maximum allowable = \( \frac{(\text{leak-off test pressure})}{0.052} \div (\text{TVD, ft RKB}) + (\text{mud wt in use, ppg}) \)

Example: Leak-off test pressure = 800 psi
TVD from rotary bushing to casing shoe = 4000 ft
Mud in use = 9.2 ppg

Maximum allowable mud weight, ppg = \( \frac{800}{0.052} \div 4000 + 9.2 \)
Maximum allowable mud weight = 13.0 ppg

Maximum Allowable Shut-in Casing (Annulus) Pressure

\[
\text{MASICP} = (\text{maximum allowable mud wt in}) \times 0.052 \times (\text{RKB to casing shoe TVD, ft})
\]

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

\[
\text{MASICP} = (13.3 \text{ ppg} - 11.5 \text{ ppg}) \times 0.052 \times 4000 \text{ ft}
\]
MASICP = 374

Casing Burst Pressure — Subsea Stack

**Step 1** Determine the internal yield pressure of the casing from the “Dimensions and Strengths” section of cement company’s service handbook.

**Step 2** Correct internal yield pressure for safety factor. Some operators use 80%; some use 75%, and others use 70%:

Correct internal yield pressure, psi = (internal yield pressure, psi) x 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.

\[
\text{HP, psi} = (\text{mud weight in use, ppg}) \times 0.052 \times (\text{TVD, ft from RKB to mud line})
\]

**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):

CBP x (corrected internal yield pressure, psi) — (HP of mud in use, psi + HP of seawater, psi)

Example:  Determine the casing burst pressure, subsea stack, using the following data:

DATA: Mud weight = 10.0 ppg  Weight of seawater = 8.7 ppg
Air gap = 50 ft  Water depth = 1500 ft
Correction (safety) factor = 80%

Step 1  Determine the internal yield pressure of the casing from the “Dimension and Strengths” section of a cement company handbook:

9-5/8” casing — C-75, 53.5 lb/ft
Internal yield pressure = 7430 psi

Step 2  Correct internal yield pressure for safety factor:

Corrected internal yield pressure = 7430 psi x 0.80
Corrected internal yield pressure = 5944 psi

Step 3  Determine the hydrostatic pressure exerted by the mud in use:

HP of mud, psi = 10.0 ppg x 0.052 x (50 ft + 1500 ft)
HP of mud = 806 psi

Step 4  Determine the hydrostatic pressure exerted by the seawater:

HPsw = 8.7 ppg x 0.052 x 1500 ft
HPsw = 679 psi

Step 5  Determine the casing burst pressure:

Casing burst pressure = 5944 psi — 806 psi + 679 psi
Casing burst pressure = 5817 psi

Calculate Choke Line Pressure Loss (CLPL), Psi

\[
\text{CLPL} = \frac{0.000061 \times MW \times \text{length, ft} \times \text{GPM}^{1.86}}{\text{choke line ID, in.}^{4.86}}
\]

Example:  Determine the choke line pressure loss (CLPL), psi, using the following data:

DATA: Mud weight = 14.0 ppg  Choke line length = 2000 ft
Circulation rate = 225 gpm  Choke line ID = 2.5 in.

\[
\text{CLPL} = \frac{0.000061 \times 14.0 \text{ ppg} \times 2000 \text{ ft} \times 225^{1.86}}{2.5^{4.86}}
\]
CLPL = 40508.611
     85.899066
CLPL = 471.58 psi

**Velocity, Ft/Mm, Through the Choke Line**

\[
V, \text{ft/mm} = \frac{24.5 \times \text{gpm}}{\text{ID, in.}^2}
\]

*Example:* Determine the velocity, ft/mm, through the choke line using the following data:

Data: Circulation rate = 225 gpm Choke line ID = 2.5 in.

\[
V = \frac{24.5 \times 225}{2.5^2}
\]

\[
V = 882 \text{ ft/min}
\]

**Adjusting Choke Line Pressure Loss for a Higher Mud Weight**

\[
\text{New CLPL} = \frac{\text{higher mud wt, ppg \times CLPL}}{\text{old mud weight, ppg}}
\]

*Example:* Use the following data to determine the new estimated choke line pressure loss:

Data: Old mud weight = 13.5 ppg
New mud weight = 15.0 ppg
Old choke line pressure loss = 300 psi

\[
\text{New CLPL} = \frac{15.0 \text{ ppg} \times 300 \text{ psi}}{13.5 \text{ ppg}}
\]

\[
\text{New CLPL} = 333.33 \text{ psi}
\]

**Minimum Conductor Casing Setting Depth**

*Example:* Using the following data, determine the minimum setting depth of the conductor casing below the seabed:

Data: Maximum mud weight (to be used while drilling this interval) = 9.0 ppg
Water depth = 450 ft Gradient of seawater = 0.445 psi/ft
Air gap = 60 ft Formation fracture gradient = 0.68 psi/ft

**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:

\[ \text{psi} = 9.0 \text{ ppg} \times 0.052 \times (60 + 450 + \text{“y”}) \]
\[ \text{psi} = [9.0 \times 0.052 \times (60 + 450)] + (9.0 \times 0.052 \times \text{“y”}) \]
\[ \text{psi} = 238.68 + 0.468 \text{“y”} \]

Step 3  Minimum conductor casing setting depth:

\[ 200.25 + 0.68 \text{“y”} = 238.68 + 0.468 \text{“y”} \]
\[ 0.68 \text{“y”} - 0.468 \text{“y”} = 238.68 - 200.25 \]
\[ 0.212 \text{“y”} = 38.43 \]
\[ \frac{\text{“y”}}{0.212} = 181.3 \text{ ft} \]

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
- Depths - Water depth = 600 ft
- Formation fracture gradient = 0.58 psi/ft
- Seawater gradient = 0.445 psi/ft

Step 1  Determine total pressure at casing seat:

\[ \text{psi} = [0.58 (1225 - 600 - 75)] + (0.445 \times 600) \]
\[ \text{psi} = 319 + 267 \]
\[ \text{psi} = 586 \]

Step 2  Determine maximum mud weight:

Max mud wt = 586 psi ÷ 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
- Seawater gradient = 0.445 psi/ft
- Mud weight = 9.0 ppg
- Water depth = 700 ft
- Well depth = 2020 ft RKB
**Step 1** Determine bottomhole pressure:

\[ BHP = 9.0 \text{ ppg} \times 0.052 \times 2020 \text{ ft} \]

\[ BHP = 945.4 \text{ psi} \]

**Step 2** Determine bottomhole pressure with riser disconnected:

\[ BHP = (0.445 \times 700) + [9.0 \times 0.052 \times (2020 - 700 - 75)] \]

\[ BHP = 311.5 + 582.7 \]

\[ BHP = 894.2 \text{ psi} \]

**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:

<table>
<thead>
<tr>
<th>Data:</th>
<th>Total depth — RKB</th>
<th>Height of gas kick in casing</th>
<th>Original mud weight</th>
<th>Choke line pressure loss</th>
<th>Annulus (casing) pressure</th>
<th>Original mud in casing below gas</th>
<th>Gas gradient</th>
<th>Kill weight mud</th>
<th>Pressure loss in annulus</th>
<th>Air gap</th>
<th>Water depth</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>13,500 ft</td>
<td>1200 ft</td>
<td>12.0 ppg</td>
<td>220 psi</td>
<td>631 psi</td>
<td>5500 ft</td>
<td>0.12 psi/ft</td>
<td>12.7 ppg</td>
<td>75 psi</td>
<td>75 ft</td>
<td>1500 ft</td>
</tr>
</tbody>
</table>

**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:

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure in choke line</td>
<td>982.8 psi</td>
</tr>
<tr>
<td>Pressure of gas influx</td>
<td>144 psi</td>
</tr>
<tr>
<td>Original mud below gas in casing</td>
<td>3432 psi</td>
</tr>
<tr>
<td>Kill weight mud</td>
<td>3450.59 psi</td>
</tr>
<tr>
<td>Annulus (casing) pressure</td>
<td>630 psi</td>
</tr>
<tr>
<td>Choke line pressure loss</td>
<td>200 psi</td>
</tr>
<tr>
<td>Annular pressure loss</td>
<td>75 psi</td>
</tr>
</tbody>
</table>

\[ \text{Annulus (casing) pressure} = 982.8 \text{ psi} \]
\[ \text{Pressure of gas influx} = 144 \text{ psi} \]
\[ \text{Original mud below gas in casing} = 3432 \text{ psi} \]
\[ \text{Kill weight mud} = 3450.59 \text{ psi} \]
\[ \text{Choke line pressure loss} = 200 \text{ psi} \]
\[ \text{Annular pressure loss} = 75 \text{ psi} \]

7. 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 by pumping kill weight fluid down the tubing and in some cases down the casing.

The Bullheading method of killing a well is primarily used in the following situations:

a) Tubing in the well with a packer set. No communication exists between tubing and annulus.
b) Tubing in the well, influx in the annulus, and for some reason, cannot circulate through the tubing.
c) No tubing in the well. Influx in the casing. Bullheading is simplest, fastest, and safest method to use to kill the well.

NOTE: Tubing could be well off bottom also.

d) In drilling operations, bullheading has been used successfully in areas where hydrogen sulphide is a possibility.

Example calculations involved in bullheading operations:

Using the information given below, the necessary calculations will be performed to kill the well by bullheading. The example calculations will pertain to “a” above:
DATA: Depth of perforations = 6480 ft  
Fracture gradient = 0.862 psi/ft  
Formation pressure gradient = 0.401 psi/ft  
Tubing hydrostatic pressure (THP) = 326 psi  
Shut-in tubing pressure = 2000 psi  
Tubing = 2-7/8 in. — 6.5 lb/ft  
Tubing capacity = 0.00579 bbl/ft  
Tubing internal yield pressure = 7260 psi  
Kill fluid density = 8.4 ppg

NOTE: Determine the best pump rate to use. The pump rate must exceed the rate of gas bubble migration up the tubing. The rate of gas bubble migration, ft/hr, in a shut-in well can be determined by the following formula:

Rate of gas migration, ft/hr = \( \frac{\text{increase in pressure per/hr, psi}}{\text{completion fluid gradient, psi/ft}} \)

Solution: Calculate the maximum allowable tubing (surface) pressure (MATP) for formation fracture:

a) MATP, initial, with influx in the tubing:

\[
\text{MATP, initial} = (\text{fracture gradient, psi/ft} \times \text{depth of perforations, ft}) - (\text{tubing hydrostatic pressure, psi})
\]

MATP, initial = (0.862 psi/ft x 6480 ft) — 326 psi  
MATP, initial = 5586 psi — 326 psi  
MATP, initial = 5260 psi

b) MATP, final, with kill fluid in tubing:

\[
\text{MATP, final} = (\text{fracture gradient, psi/ft} \times \text{depth of perforations, ft}) - (\text{tubing hydrostatic pressure, psi})
\]

MATP, final = (0.862 x 6480) — (8.4 x 0.052 x 6480)  
MATP, final = 5586 psi — 2830 psi  
MATP, final = 2756 psi

Determine tubing capacity:

Tubing capacity, bbl = tubing length, ft x tubing capacity, bbl/ft

Tubing capacity bbl, = 6480 ft x 0.00579 bbl/ft  
Tubing capacity = 37.5 bbl
Plot these values as shown below:

![Figure 4-3. Tubing pressure profile.](image)

**Lubricate and Bleed**

The lubricate and bleed method involves alternately pumping a kill fluid into the tubing or into the casing if there is no tubing in the well, allowing the kill fluid to fall, then bleeding off a volume of gas until kill fluid reaches the choke. As each volume of kill fluid is pumped into the tubing, the SITP should decrease by a calculated value until the well is eventually killed.

This method is often used for two reasons: 1) shut-in pressures approach the rated working pressure of the wellhead or tubing and dynamic pumping pressure may exceed the limits, as in the case of bullheading, and 2) either to completely kill the well or lower the SITP to a value where other kill methods can be safely employed without exceeding rated limits.

This method can also be applied when the wellbore or perforations are lugged, rendering bullheading useless. In this case, the well can be killed without necessitating 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 minimise 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:

\[
\begin{align*}
\text{TVD} & = 6500 \text{ ft} & \text{Depth of perforations} & = 6450 \text{ ft} \\
\text{SITP} & = 2830 \text{ psi} & \text{Tubing} & = 6.5 \text{ lb/ft-N-80} & = 2-7/8 \text{ in.} \\
\text{Kill fluid density} & = 9.0 \text{ ppg} & \text{Wellhead working pressure} & = 3000 \text{ psi} \\
\text{Tubing internal yield} & = 10,570 \text{ psi} & \text{Tubing capacity} & = 0.00579 \text{ bbl/ft} & (172.76 \text{ ft/bbl})
\end{align*}
\]

Calculations: Calculate the expected pressure reduction for each barrel of kill fluid pumped:

\[
\text{psi/bbl} = \text{tubing capacity, ft/bbl x 0.052 x kill weight fluid, ppg} \\
\text{psi/bbl} = 172.76 \text{ ft/bbl x 0.052 x 9.0 ppg} \\
\text{psi/bbl} = 80.85
\]

For each one barrel pumped, the SITP will be reduced by 80.85 psi.

Calculate tubing capacity, bbl, to the perforations:

\[
\text{bbl} = \text{tubing capacity, bbl/ft x depth to perforations, ft} \\
\text{bbl} = 0.00579 \text{ bbl/ft x 6450 ft} \\
\text{bbl} = 37.3 \text{ bbl}
\]

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 1/4 to 1 hour depending on gas density, pressure, and tubing size.
6. Open the choke and bleed gas until 9.0 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 not to allow fluid to fall, but rather, for gas to migrate up through the kill fluid. Gas migrates at rates of 1000 to 2000 ft/hr. Therefore considerable time is required for fluid to fall or migrate to 6500 ft. Therefore, after pumping, it is important to wait several minutes before bleeding gas to prevent bleeding off kill fluid through the choke.
References


Various Well Control Schools/Courses/Manuals
- NL Baroid, Houston, Texas
- Milchem Well Control, Houston, Texas
- Petroleum Extension Service, Univ. of Texas, Houston, Texas
- Aberdeen Well Control School, Gene Wilson, Aberdeen, Scotland
CHAPTER FIVE

ENGINEERING CALCULATIONS
1. **Bit Nozzle Selection — Optimised Hydraulics**

These series of formulas will determine the correct jet sizes when optimising for jet impact or hydraulic horsepower and optimum flow rate for two or three nozzles.

1. **Nozzle area, sq in.**
   
   \[
   \text{Nozzle area, sq in.} = \frac{N1^2 + N2^2 + N3^2}{1303.8}
   \]

2. **Bit nozzle pressure loss, psi (Pb):**
   
   \[
   Pb = \frac{\text{gpm}^2 \times \text{MW, ppg}}{10858 \times \text{nozzle area, sq in.}^2}
   \]

3. **Total pressure losses except bit nozzle pressure loss, psi (Pc):**
   
   \[Pc_1 \text{ & } Pc_2 = \text{circulating pressure, psi — bit nozzle pressure Loss.}\]

4. **Determine slope of line M:**
   
   \[M = \log \left( \frac{Pc_1}{Pc_2} \right) \div \log \left( \frac{Q_1}{Q_2} \right)\]

5. **Optimum pressure losses (Popt)**
   
   a) **For impact force:**
      
      \[Popt = \frac{2}{M+2} \times Pmax\]
   
   b) **For hydraulic horsepower:**
      
      \[Popt = \frac{1}{M+1} \times Pmax\]

6. **For optimum flow rate (Qopt):**
   
   a) **For impact force:**
      
      \[Qopt, \text{gpm} = \frac{(Popt)^{1+M} \times Q1}{Pmax}\]
   
   b) **For hydraulic horsepower:**
      
      \[Qopt, \text{gpm} = \frac{(Popt)^{1+M} \times Q1}{Pmax}\]

7. **To determine pressure at the bit (Pb):**
   
   \[Pb = Pmax - Popt\]

8. **To determine nozzle area, sq in.:**
   
   \[\text{Nozzle area, sq in.} = \sqrt{\frac{Qopt^2 \times \text{MW, ppg}}{10858 \times Pmax}}\]

9. **To determine nozzles, 32nd in. for three nozzles:**
   
   \[\text{Nozzles} = \sqrt{\frac{\text{Nozzle area, sq in.} \times 32}{3 \times 0.7854}}\]

10. **To determine nozzles, 32nd in. for two nozzles:**
    
    \[\text{Nozzles} = \sqrt{\frac{\text{Nozzle area, sq in.} \times 32}{2 \times 0.7854}}\]
**Example:** Optimise 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
- Maximum surface pressure = 3000 psi
- Pump rate 1 = 420 gpm
- Pump pressure 1 = 3000 psi
- Pump rate 2 = 275 gpm
- Pump pressure 2 = 1300 psi
- Jet sizes = 17-17-17

1. **Nozzle area, sq in.:**

   \[
   \text{Nozzle area, sq in.} = \frac{17^2 + 17^2 + 17^2}{1303.8}
   \]

   Nozzle area, sq in. = 0.664979

2. **Bit nozzle pressure loss, psi (Pb):**

   \[
   Pb_1 = \frac{420^2 \times 13.0}{10858 \times 0.6649792}
   \]

   \[
   Pb_1 = 478 \text{ psi}
   \]

   \[
   Pb_2 = \frac{275^2 \times 13.0}{10858 \times 0.6649792}
   \]

   \[
   Pb_2 = 205 \text{ psi}
   \]

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):**

   \[
   M = \log \left( \frac{2522 \div 1095}{420 \div 275} \right)
   \]

   \[
   M = 0.3623309
   \]

   M = 0.1839166

   M = 1.97

5. **Determine optimum pressure losses, psi (Popt):**

   a) **For impact force:**

   \[
   Popt = \frac{2}{1.97 + 2} \times 3000
   \]

   \[
   Popt = 1511 \text{ psi}
   \]
b) For hydraulic horsepower: \[ P_{opt} = \frac{1}{1.97 + 1} x 3000 \]
\[ P_{opt} = 1010 \text{ psi} \]

6. Determine optimum flow rate (Q_{opt}):

a) For impact force: \[ Q_{opt, gpm} = \frac{(1511)^{1+0.97}}{3000} x 420 \]
\[ Q_{opt} = 297 \text{ gpm} \]

b) For hydraulic horsepower: \[ Q_{opt, gpm} = \frac{(1010)^{1+0.97}}{3000} x 420 \]
\[ Q_{opt} = 242 \text{ gpm} \]

7. Determine pressure losses at the bit (Pb):

a) For impact force: \[ P_{b} = 3000 \text{ psi} - 1511 \text{ psi} \]
\[ P_{b} = 1489 \text{ psi} \]

b) For hydraulic horsepower: \[ P_{b} = 3000 \text{ psi} - 1010 \text{ psi} \]
\[ P_{b} = 1990 \text{ psi} \]

8. Determine nozzle area, sq in.:

a) For impact force: \[ \text{Nozzles area, sq. in.} = \sqrt{\frac{297^2 x 13.0}{10858 x 1489}} \]
\[ \text{Nozzles area, sq. in.} = \sqrt{0.070927} \]
\[ \text{Nozzle area, sq. in.} = 0.26632 \]

b) For hydraulic horsepower: \[ \text{Nozzles area, sq. in.} = \sqrt{\frac{242^2 x 13.0}{10858 x 1990}} \]
\[ \text{Nozzles area, sq. in.} = \sqrt{0.03523} \]
\[ \text{Nozzle area, sq. in.} = 0.1877 \]

9. Determine nozzle size, 32nd in.:

a) For impact force: \[ \text{Nozzles} = \sqrt{\frac{0.26632}{3 x 0.7854}} x 32 \]
\[ \text{Nozzles} = 10.76 \]

b) For hydraulic horsepower: \[ \text{Nozzles} = \sqrt{\frac{0.1877}{3 x 0.7854}} x 32 \]
\[ \text{Nozzles} = 9.03 \]
**Formulas and Calculations**

**NOTE:** Usually the nozzle size will have a decimal fraction. The fraction times 3 will determine how many nozzles should be larger than that calculated.

a) For impact force: \[ 0.76 \times 3 = 2.28 \text{ rounded to 2} \]
so: 1 jet = 10/32nds
2 jets = 11/32nds

b) For hydraulic horsepower: \[ 0.03 \times 3 = 0.09 \text{ rounded to 0} \]
so: 3 jets = 9/32 nd in.

10. Determine nozzles, 32nd in. for two nozzles:

a) For impact force: \[ \text{Nozzles} = \sqrt{\frac{0.26632}{2 \times 0.7854} \times 32} \]
Nozzles = 13.18 sq in.

b) For hydraulic horsepower: \[ \text{Nozzles} = \sqrt{\frac{0.1877}{2 \times 0.7854} \times 32} \]
Nozzles = 11.06 sq in.

### 2. Hydraulics Analysis

This sequence of calculations is designed to quickly and accurately analyse various parameters of existing bit hydraulics.

1. Annular velocity, ft/mm (AV):
   \[ \text{AV} = \frac{24.5 \times Q}{Dh^2 - Dp^2} \]

2. Jet nozzle pressure loss, psi (Pb):
   \[ \text{Pb} = 156.5 \times \frac{Q^2 \times MW}{[(N_1)^2 + (N_2)^2 + (N_3)^2]^2} \]

3. System hydraulic horsepower available (Sys HHP):
   \[ \text{SysHHP} = \frac{\text{surface, psi} \times Q}{1714} \]

4. Hydraulic horsepower at bit (HHPb):
   \[ \text{HHPb} = \frac{Q \times Pb}{1714} \]

5. Hydraulic horsepower per square inch of bit diameter:
   \[ \text{HHPb/sq in.} = \frac{\text{HHPb} \times 1.27}{\text{bit size}^2} \]

6. Percent pressure loss at bit (% psib):
   \[ \%\text{psib} = \frac{\text{Pb}}{\text{surface, psi}} \times 100 \]

7. Jet velocity, ft/sec (Vn):
   \[ \text{Vn} = \frac{417.2 \times Q}{(N_1)^2 + (N_2)^2 + (N_3)^2} \]

8. Impact force, lb, at bit (IF):
   \[ \text{IF} = \frac{(\text{MW}) \times (\text{Vn}) \times (Q)}{1930} \]
9. Impact force per square inch of bit area (IF/sq in.): 

\[ IF/sq \text{ in.} = \frac{IF}{\text{bit size}^2} \]

**Nomenclature:**

- \( AV \) = annular velocity, ft/mm
- \( Q \) = circulation rate, gpm
- \( Dh \) = hole diameter, in.
- \( Dp \) = pipe or collar OD, in.
- \( MW \) = mud weight, ppg
- \( N_1, N_2, N_3 \) = jet nozzle sizes, 32nd in.
- \( Pb \) = bit nozzle pressure loss, psi
- \( Vn \) = jet velocity, ft/sec
- \( HHP \) = hydraulic horsepower at bit
- \( IF \) = impact force, lb

\( IF/sq \text{ in.} = \) impact force lb/sq in of bit diameter

**Example:**

Mud weight = 12.0 ppg
Nozzle size 1 = 12-32nd/in.
Nozzle size 2 = 12-32nd/in.
Nozzle size 3 = 12-32nd/in.

1. Annular velocity, ft/mm:

\[ AV = \frac{24.5 \times 520}{12.25^2 - 5.0^2} \]
\[ AV = 12740 \]
\[ AV = 102 \text{ ft/mm} \]

2. Jet nozzle pressure loss:

\[ Pb = \frac{156.5 \times 520^2 \times 12.0}{(12^2 + 12^2 + 12^2)^2} \]
\[ Pb = 2721 \text{ psi} \]

3. System hydraulic horsepower available:

\[ \text{Sys HHP} = \frac{3000 \times 520}{1714} \]
\[ \text{Sys HHP} = 910 \]

4. Hydraulic horsepower at bit:

\[ \text{HHPb} = \frac{2721 \times 520}{1714} \]
\[ \text{HHPb} = 826 \]

5. Hydraulic horsepower per square inch of bit area:

\[ \text{HHP/sq in.} = \frac{826 \times 1.27}{12.252} \]
\[ \text{HHP/sq in.} = 6.99 \]

6. Percent pressure loss at bit:

\[ \% \text{ psib} = \frac{2721 \times 100}{3000} \]
\[ \% \text{ psib} = 90.7 \]
7. Jet velocity, ft/sec: 
\[ V_n = \frac{417.2 \times 520}{12^2 + 12^2 + 12^2} \]
\[ V_n = 216944 \]
\[ V_n = 502 \text{ ft/sec} \]

8. Impact force, lb: 
\[ IF = \frac{12.0 \times 502 \times 520}{1930} \]
\[ IF = 1623 \text{ lb} \]

9. Impact force per square inch of bit area: 
\[ \frac{IF}{\text{sq in.}} = \frac{1623 \times 1.27}{12.25^2} \]
\[ \frac{IF}{\text{sq in.}} = 13.7 \]

---

### 3. Critical Annular Velocity and Critical Flow Rate

1. Determine \( n \): 
\[ n = 3.32 \log \frac{\phi 600}{\phi 300} \]

2. Determine \( K \): 
\[ K = \frac{\phi 600}{1022^n} \]

3. Determine \( X \): 
\[ X = \frac{81600 (Kp) (n)^{0.387}}{(Dh - Dp)^n} \cdot MW \]

4. Determine critical annular velocity: 
\[ AV_c = \frac{(X)^{1 + \frac{2}{n}}}{24.5} \]

5. Determine critical flow rate: 
\[ GPM_c = AV_c \frac{(Dh^2 - Dp^2)}{24.5} \]

**Nomenclature:**

- \( n \) = dimensionless
- \( K \) = dimensionless
- \( X \) = dimensionless
- \( \phi 600 \) = 600 viscometer dial reading
- \( \phi 300 \) = 300 viscometer dial reading
- \( Dh \) = hole diameter, in.
- \( Dp \) = pipe or collar OD, in.
- \( MW \) = mud weight, ppg
- \( Avc \) = critical annular velocity, ft/mm
- \( GPMc \) = critical flow rate, gpm

**Example:**
- Mud weight = 14.0 ppg
- \( \phi 600 = 64 \)
- \( \phi 300 = 37 \)
- Hole diameter = 8.5 in.
- Pipe OD = 7.0 in.
1. Determine n: 
   \[ n = 3.32 \log_{37} 64 \]
   \[ n = 0.79 \]

2. Determine K: 
   \[ K = \frac{64}{1022^{0.79}} \]
   \[ K = 0.2684 \]

3. Determine X: 
   \[ X = \frac{81600(0.2684)(0.79)0.387}{8.5 - 70.79 \times 14.0} \]
   \[ X = \frac{19967.413}{19.2859} \]
   \[ X = 1035 \]

4. Determine critical annular velocity: 
   \[ AV_c = \frac{(1035)^{1 \div (2 - 0.79)}}{0.8264} \]
   \[ AV_c = 310 \text{ ft/mm} \]

5. Determine critical flow rate: 
   \[ GPM_c = 310 \frac{(8.52 - 7.02)}{24.5} \]
   \[ GPM_c = 294 \text{ gpm} \]

4. “d” Exponent

The “d” exponent is derived from the general drilling equation: 
   \[ R \div N = a(W^d \div D) \]

where:
- \( R \) = penetration rate
- \( N \) = rotary speed, rpm
- \( W \) = weight on bit, lb
- \( a \) = a constant, dimensionless
- \( d \) = exponent in general drilling equation, dimensionless

“d” exponent equation: 
   \[ d = \log \left( \frac{R}{60N} \right) \div \log \left( \frac{12W}{1000D} \right) \]

where:
- \( d \) = \( d \) exponent, dimensionless
- \( R \) = penetration rate, ft/hr
- \( N \) = rotary speed, rpm
- \( W \) = weight on bit, 1,000 lb
- \( D \) = bit size, in.

Example: \( R = 30 \text{ ft/hr} \) \( N = 120 \text{ rpm} \) \( W = 35,000 \text{ lb} \) \( D = 8.5 \text{ in.} \)

Solution:
   \[ d = \log \left( \frac{30}{60 \times 120} \right) \div \log \left( \frac{12 \times 35}{1000 \times 8.5} \right) \]
   \[ d = \log \left( \frac{30}{7200} \right) \div \log \left( \frac{420}{8500} \right) \]
   \[ d = \log 0.0042 \div \log 0.0494 \]
   \[ d = \frac{2.377}{1.306} \]
   \[ d = 1.82 \]
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:

\[ d_c = d \left( \frac{MW_1}{MW_2} \right) \]

where  
\( d_c \) = corrected “d” exponent  
\( MW_1 \) = normal mud weight — 9.0 ppg  
\( MW_2 \) = actual mud weight, ppg

Example:  
\( d = 1.64 \)  
\( MW_1 = 9.0 \text{ ppg} \)  
\( MW_2 = 12.7 \text{ ppg} \)

Solution:  
\[ d_c = 1.64 \left( \frac{9.0}{12.7} \right) \]
\[ d_c = 1.64 \times 0.71 \]
\[ d_c = 1.16 \]

5. **Cuttings Slip Velocity**

These calculations give the slip velocity of a cutting of a specific size and weight in a given fluid. The annular velocity and the cutting net rise velocity are also calculated.

**Method 1**

Annular velocity, ft/mm:  
\[ AV = 24.5 \times \frac{Q}{Dh^2 - Dp^2} \]

Cuttings slip velocity, ft/mm:  
\[ Vs = 0.45 \left( \frac{PV}{MW(Dp)} \right) \left[ \sqrt{36,800 \div (PV \div (MW)(Dp))^2} \times (Dp)((DenP \div MW) - 1) + 1^{\frac{1}{2}} \right] \]

where  
\( Vs \) = slip velocity, ft/min  
\( PV \) = plastic viscosity, cps  
\( MW \) = mud weight, ppg  
\( Dp \) = diameter of particle, in.  
\( DenP \) = density of particle, ppg

**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/mm:  
\[ AV = \frac{24.5 \times 520}{12.25^2 - 5.0^2} \]
\[ AV = 102 \text{ ft/min} \]
Cuttings slip velocity, ft/mm:

\[ Vs = 0.45\left(\frac{13}{\sqrt{36,800 \div (13 \div (11 \times 0.25))^2 \times 0.25((22 \div 11) - 1) + 1^{-1}}\right) \]

\[ Vs = 0.45\left[4.7271 \sqrt{36,800 \div [4.727]^2 \times 0.25 \times 1 + 1 - 1}\right] \]

\[ Vs = 2.12715 \sqrt{412.68639 - 1} \]

\[ Vs = 2.12715 \times 19.3146 \]

\[ Vs = 41.085 \text{ ft/mm} \]

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 \( n \):

\[ n = 3.32 \log \frac{\phi_{600}}{\phi_{300}} \]

2. Determine \( K \):

\[ K = \frac{\phi_{600}}{511^n} \]

3. Determine annular velocity, ft/mm:

\[ v = \frac{24.5 \times Q}{Dh^2 - Dp^2} \]

4. Determine viscosity (\( \mu \)):

\[ \mu = \left(\frac{2.4v}{2n + 1}\right)x\left(\frac{200K(Dh - Dp)}{Dh-Dp\times3n}\right)\times175 \times DiaP \]

\[ MW^{0.333} \times \mu^{0.333} \]

5. Slip velocity (\( Vs \)), ft/mm:

\[ Vs = \frac{(DensP - MW)^{0.667} \times 175 \times DiaP}{MW^{0.333} \times \mu^{0.333}} \]

Nomenclature:

\( n \) = dimensionless
\( K \) = dimensionless
\( \phi_{600} \) = 600 viscometer dial reading
\( \phi_{300} \) = 300 viscometer dial reading
\( Dp \) = pipe or collar OD, in.
\( v \) = annular velocity, ft/min
\( \mu \) = mud viscosity, cps

Example: Using the data listed below, determine the annular velocity, cuttings slip velocity, and the cutting net rise velocity:

DATA:

Mud weight = 11.0 ppg
Yield point = 10 lb/100 sq. ft
Hole diameter = 12.25 in.
Drill pipe OD = 5.0 in.
Plastic viscosity = 13 cps
Diameter of particle = 0.25 in.
Density of particle = 22.0 ppg
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/mm: 
\[ v = \frac{24.5 \times 520}{12.25^2 - 5.0^2} \]
\[ v = \frac{12.740}{125.06} \]
\[ v = 102 \text{ ft/min} \]

4. Determine mud viscosity, cps:
\[ \mu = \left( \frac{2.4 \times 102 \times 2(0.64599) + 1}{12.25 - 5.0} \right)^{0.64599} \times \frac{200 \times 0.4094 \times (12.25 - 5)}{3 \times 0.64599} \]
\[ \mu = \left( \frac{2448 \times 2.292}{7.25 \times 1.938} \right)^{0.64599} \times 593.63 \]
\[ \mu = \left( \frac{33.76 \times 1.1827}{1.1827} \right)^{0.64599} \times 5.82 \]
\[ \mu = 10.82 \times 5.82 \]
\[ \mu = 63 \text{ cps} \]

5. Determine slip velocity \( (V_s) \), ft/mm: 
\[ V_s = \left( \frac{22 - 11}{11^{0.333} \times 63^{0.333}} \right)^{0.667} \times 175 \times 0.25 \]
\[ V_s = \frac{4.95 \times 175 \times 0.25}{2.222 \times 3.97} \]
\[ V_s = 216.56 \]
\[ V_s = 8.82 \]
\[ V_s = 24.55 \text{ ft/min} \]

6. Determine cuttings net rise velocity, ft/mm: 
Annular velocity = 102 ft/mm
Cuttings slip velocity = 24.55 ft/mm
Cuttings net rise velocity = 77.45 ft/mm
6. **Surge and Swab Pressures**

**Method 1**

1. Determine \( n \):
   \[
   n = 3.32 \log \frac{\phi_{600}}{\phi_{300}}
   \]

2. Determine \( K \):
   \[
   K = \frac{\phi_{600}}{511^n}
   \]

3. Determine velocity, \( v \)\( \text{ft/min} \):
   For plugged flow:
   \[
   v = \left[ 0.45 + \frac{D_p^2}{D_h^2 - D_p^2} \right] V_p
   \]
   For open pipe:
   \[
   v = \left[ 0.45 + \frac{D_p^2 - D_i^2}{D_h^2 - D_p^2 + D_i^2} \right] V_p
   \]

4. Maximum pipe velocity:
   \[
   V_m = 1.5 \times v
   \]

5. Determine pressure losses:
   \[
   P_s = \left( \frac{2.4 V_m}{D_h - D_p} \right)^n \times \frac{2n + 1}{3n} \times \frac{K L}{300 (D_h - D_p)}
   \]

**Nomenclature:**

- \( n \) = dimensionless
- \( K \) = dimensionless
- \( \phi_{600} \) = 600 viscometer dial reading
- \( \phi_{300} \) = 300 viscometer dial reading
- \( D_p \) = drill pipe or drill collar OD, in.
- \( D_i \) = drill pipe or drill collar ID, in.
- \( D_h \) = hole diameter, in.
- \( V_p \) = pipe velocity, \( \text{ft/min} \)
- \( V_m \) = maximum pipe velocity, \( \text{ft/mm} \)
- \( L \) = pipe length, ft
- \( P_s \) = pressure loss, psi
- \( V_m \) = fluid velocity, \( \text{ft/min} \)
- \( L \) = pipe length, ft
- \( K \) = pipe velocity, \( \text{ft/min} \)

**Example 1:** Determine surge pressure for plugged pipe:

**Data:**
- Well depth = 15,000 ft
- Hole size = 7-7/8 in.
- Drill collar length = 700 ft
- Average pipe running speed = 270 ft/mm
- Drill collar = 6-1/4” OD x 2-3/4” ID
- Viscometer readings: \( \phi_{600} = 140 \), \( \phi_{300} = 80 \)

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/mm:  

\[ v = \left( 0.45 + \frac{4.5^2}{7.875^2 - 4.5^2} \right) \times 270 \]

\[ v = (0.45 + 0.484) \times 270 \]

\[ v = 252 \, \text{ft/min} \]

4. Determine maximum pipe velocity, ft/min:  

\[ V_m = 1.5 \times 252 \]

\[ V_m = 378 \, \text{ft/min} \]

5. Determine pressure losses, psi:  

\[ P_s = \left[ 2.4 \times 378 \times \frac{2(0.8069) + 1}{3(0.8069)} \times \frac{(0.522)(14300)}{300(7.875 - 4.5)} \right] \times \frac{7.875 - 4.5}{3(0.8069)} \]

\[ P_s = (268.8 \times 1.1798) \times \frac{7464.5}{1012.5} \]

\[ P_s = 97.098 \times 7.37 \]

\[ P_s = 716 \, \text{psi surge pressure} \]

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/mm:  

\[ v = \left( 0.45 + \frac{4.5^2 - 3.82^2}{7.875^2 - 4.5^2 + 3.82^2} \right) \times 270 \]

\[ v = (0.45 + 5.66) \times 270 \]

\[ v = 56.4 \]

\[ v = (0.45 + 0.100) \times 270 \]

\[ v = 149 \, \text{ft/mm} \]

2. Maximum pipe velocity, ft/mm:  

\[ V_m = 149 \times 1.5 \]

\[ V_m = 224 \, \text{ft/mm} \]

3. Pressure loss, psi:  

\[ P_s = \left[ 2.4 \times 224 \times \frac{2(0.8069) + 1}{3(0.8069)} \times \frac{(0.522)(14300)}{300(7.875 - 4.5)} \right] \times \frac{7.875 - 4.5}{3(0.8069)} \]

\[ P_s = (159.29 \times 1.0798) \times \frac{7464.5}{1012.5} \]

\[ P_s = 63.66 \times 7.37 \]

\[ P_s = 469 \, \text{psi surge pressure} \]

Therefore, this pressure would be added to the hydrostatic pressure of the mud in the wellbore.
If, however, the swab pressure is desired, this pressure would be subtracted from the hydrostatic pressure of the mud in the wellbore.

**Method 2**

Surge and swab pressures

Assume:  
1) Plugged pipe  
2) Laminar flow around drill pipe  
3) Turbulent flow around drill collars

These calculations outline the procedure and calculations necessary to determine the increase or decrease in equivalent mud weight (bottomhole pressure) due to pressure surges caused by pulling or running pipe. These calculations assume that the end of the pipe is plugged (as in running casing with a float shoe or drill pipe with bit and jet nozzles in place), not open ended.

A. Surge pressure around drill pipe:

1. Estimated annular fluid velocity ($v$) around drill pipe:  
   $$v = \left[ 0.45 + \frac{Dp^2}{Dh^2 - Dp^2} \right] Vp$$

2. Maximum pipe velocity ($V_m$):  
   $$V_m = v \times 1.5$$

3. Determine $n$:  
   $$n = 3.32 \log \frac{\phi_{600}}{\phi_{300}}$$

4. Determine $K$:  
   $$K = \frac{\phi_{600}}{511^n}$$

5. Calculate the shear rate ($Y_m$) of the mud moving around the pipe:  
   $$Y_m = \frac{2.4 \times V_m}{Dh - Dp}$$

6. Calculate the shear stress ($T$) of the mud moving around the pipe:  
   $$T = K \times (Y_m)^n$$

7. Calculate the pressure ($P_s$) decrease for the interval:  
   $$P_s = 3.33 \left( \frac{T \times L}{Dh - Dp} \right) x \frac{1000}{1000}$$

B. Surge pressure around drill collars:

1. Calculate the estimated annular fluid velocity ($v$) around the drill collars:  
   $$v = \left[ 0.45 + \frac{Dp^2}{Dh^2 - Dp^2} \right] Vp$$

2. Calculate maximum pipe velocity ($V_m$):  
   $$V_m = v \times 1.5$$
Formulas and Calculations

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flow rate (Q):

\[ Q = \frac{V_m \left[ (D_h)^2 - (D_p)^2 \right]}{24.5} \]

4. Calculate the pressure loss for each interval (Ps):

\[ Ps = 0.000077 \times MW^{0.8} \times Q^{1.8} \times PV^{0.2} \times L \]

\[ (D_h - D_p)^{3} \times (D_h + D_p)^{1.8} \]

C. Total surge pressures converted to mud weight:

Total surge (or swab) pressures: \[ \text{psi} = Ps \text{ (drill pipe)} + Ps \text{ (drill collars)} \]

D. If surge pressure is desired: \[ \text{SP, ppg} = Ps \div 0.052 \div \text{TVD, ft} + \text{“+” MW, ppg} \]

E. If swab pressure is desired: \[ \text{SP, ppg} = Ps \div 0.052 \div \text{TVD, ft} - \text{“−” MW, ppg} \]

Example:

Determine both the surge and swab pressure for the data listed below:

Data:
- Mud weight = 15.0 ppg
- Plastic viscosity = 60 cps
- Yield point = 20 lb/100 sq ft
- Hole diameter = 7-7/8 in.
- Drill pipe OD = 4-1/2 in.
- Drill pipe length = 14,300 ft
- Drill collar OD = 6-1/4 in.
- Drill collar length = 700 ft
- Pipe running speed = 270 ft/min

A. Around drill pipe:

1. Calculate annular fluid velocity (v) around drill pipe:

\[ v = \left[ 0.45 + \frac{(45)^2}{7.875^2 - 4.5^2} \right] \times 270 \]

\[ v = [0.45 + 0.4848] \times 270 \]

\[ v = 253 \text{ ft/min} \]

2. Calculate maximum pipe velocity (V_m):

\[ V_m = 253 \times 1.5 \]

\[ V_m = 379 \text{ ft/min} \]

NOTE: Determine n and K from the plastic viscosity and yield point as follows:

\[ PV + YP = \phi 300 \text{ reading} \]

\[ \phi 300 \text{ reading} + PV = \phi 600 \text{ reading} \]

Example:

\[ PV = 60 \quad YP = 20 \]

\[ 60 + 20 = 80 \text{ (} \phi 300 \text{ reading}) \quad 80 + 60 = 140 \text{ (} \phi 600 \text{ reading}) \]

3. Calculate n:

\[ n = 3.32 \log \frac{80}{140} \]

\[ n = 0.8069 \]

4. Calculate K:

\[ K = \frac{80}{511^{0.8069}} \]

\[ K = 0.522 \]
5. Calculate the shear rate \((Y_m)\) of the mud moving around the pipe:

\[
Y_m = \frac{2.4 \times 379}{(7.875 - 4.5)}
\]

\[
Y_m = 269.5
\]

6. Calculate the shear stress \((T)\) of the mud moving around the pipe:

\[
T = 0.522 \times (269.5)^{0.8069}
\]

\[
T = 0.522 \times 91.457
\]

\[
T = 47.74
\]

7. Calculate the pressure decrease \((P_s)\) for the interval:

\[
P_s = \frac{3.33 \times (47.7)}{(7.875 - 4.5)} \times \frac{14,300}{1000}
\]

\[
P_s = 47.064 \times 14.3
\]

\[
P_s = 673 \text{ psi}
\]

B. Around drill collars:

1. Calculate the estimated annular fluid velocity \((v)\) around the drill collars:

\[
v = \left[ 0.45 + \frac{6.25^2}{(7.875^2 - 6.25^2)} \right] 270
\]

\[
v = (0.45 + 1.70) \times 270
\]

\[
v = 581 \text{ ft/mm}
\]

2. Calculate maximum pipe velocity \((V_m)\):

\[
V_m = 581 \times 1.5
\]

\[
V_m = 871.54 \text{ ft/mm}
\]

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flow-rate \((Q)\):

\[
Q = \frac{871.54 \times (7.875^2 - 6.25^2)}{24.5}
\]

\[
Q = \frac{20004.567}{24.5}
\]

\[
Q = 816.5
\]

4. Calculate the pressure loss \((P_s)\) for the interval:

\[
P_s = \frac{0.000077 \times 15^{0.8} \times 816^{1.8} \times 60^{0.2} \times 700}{(7.875 - 6.25)^3 \times (7.875 + 6.25)^{1.8}}
\]

\[
P_s = 185837.9
\]

\[
P_s = 504.126
\]

\[
P_s = 368.6 \text{ psi}
\]

C. Total pressures:

\[
\text{psi} = 672.9 \text{ psi} + 368.6 \text{ psi}
\]

\[
\text{psi} = 1041.5 \text{ psi}
\]

D. Pressure converted to mud weight, ppg:

\[
\text{ppg} = \frac{1041.5 \text{ psi}}{0.052} \div \frac{15,000 \text{ ft}}{15,000 \text{ ft}}
\]

\[
\text{ppg} = 1.34
\]
E. If surge pressure is desired:  
Surge pressure, ppg = 15.0 ppg + 1.34 ppg  
Surge pressure = 16.34 ppg

F. If swab pressure is desired:  
Swab pressure, ppg = 15.0 ppg — 1.34 ppg  
Swab pressure = 13.66 ppg

7. **Equivalent Circulation Density (ECD)**

1. Determine n:  
\[ n = 3.32 \log \frac{\phi_{600}}{\phi_{300}} \]

2. Determine K:  
\[ K = \frac{\phi_{600}}{511^n} \]

3. Determine annular velocity \( (v) \), ft/mm:  
\[ v = \frac{24.5 \times Q}{D_h^2 - D_p^2} \]

4. Determine critical velocity \( (V_c) \), ft/mm:  
\[ V_c = \frac{(3.878 \times 10^4 \times K)_{1+\left(2-n\right)} \times \left(\frac{2.4}{3n} \times n + 1\right)^{(n+\left(2-n\right))}}{M_W \times D_h - D_p} \]

5. Pressure loss for laminar flow \( (P_s) \), psi:  
\[ P_s = \left(\frac{2.4v}{3n} \times \frac{2n+1}{3n} \times KL}{D_h - D_p} \times \frac{300}{3n} \times \frac{D_h - D_p}{D_h + D_p} \]

6. Pressure loss for turbulent flow \( (P_s) \), psi:  
\[ P_s = 7.7 \times 10^{-5} \times M_W^{0.8} \times Q^{1.8} \times PV^{0.2} \times L \]

7. Determine equivalent circulating density (ECD), ppg:  
\[ ECD, \ ppg = P_s - 0.052 \ TVD, \ ft + 0 \ MW, \ ppg \]

**Example:**  
Equivalent circulating density (ECD), ppg:

**Data:**  
Mud weight = 12.5 ppg  
Plastic viscosity = 24 cps  
Yield point = 12 lb/100 sq ft  
Circulation rate = 400 gpm  
Drill collar OD = 6.5 in.  
Drill pipe OD = 5.0 in  
Drill collar length = 700 ft  
Drill pipe length = 11,300 ft  
True vertical depth = 12,000 ft  
Hole diameter = 8.5 in.

**NOTE:** If \( \phi_{600} \) and \( \phi_{300} \) 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 \( \phi_{300} \) reading.  
\[ 36 + 24 = 60 \]  
Thus, 60 is the \( \phi_{600} \) reading.
1. Determine n: 
\[ n = \frac{3.3210g 60}{36} \]
\[ n = 0.7365 \]

2. Determine K: 
\[ K = \frac{36}{511^{0.7365}} \]
\[ K = 0.3644 \]

3a. Determine annular velocity (v), ft/mm, around drill pipe: 
\[ v = \frac{24.5 \times 400}{8.5^2 - 5.0^2} \]
\[ v = 207 \text{ ft/mm} \]

3b. Determine annular velocity (v), ft/mm, around drill collars: 
\[ v = \frac{24.5 \times 400}{8.5^2 - 6.5^2} \]
\[ v = 327 \text{ ft/mm} \]

4a. Determine critical velocity (Vc), ft/mm, around drill pipe: 
\[ Vc = \left(3.878 \times 10^4 \times 0.3644\right)^{1+(2-0.7365)} \times \frac{2.4}{8.5-5.0} \times \frac{2(0.7365)+1}{3(0.7365)}^{(0.7365 + (2-0.7365))} \]
\[ Vc = (1130.5)^{0.791} \times (0.76749)^{0.5829} \]
\[ Vc = 260 \times 0.857 \]
\[ Yc = 223 \text{ ft/mm} \]

4b. Determine critical velocity (Yc), ft/mm, around drill collars: 
\[ Vc = \left(3.878 \times 10^4 \times 0.3644\right)^{1+(2-0.7365)} \times \frac{2.4}{8.5-6.5} \times \frac{2(0.7365)+1}{3(0.7365)}^{(0.7365 + (2-0.7365))} \]
\[ Vc = (1130.5)^{0.791} \times (1.343)^{0.5829} \]
\[ Vc = 260 \times 1.18756 \]
\[ Vc = 309 \text{ ft/mm} \]

Therefore: 
- Drill pipe: 207 ft/mm (v) is less than 223 ft/mm (Vc), Laminar flow, so use Equation 5 for pressure loss.
- Drill collars: 327 ft/mm (v) is greater than 309 ft/mm (Vc) turbulent flow, so use Equation 6 for pressure loss.

5. Pressure loss opposite drill pipe:
\[ Ps = \left[ \frac{2.4 \times 207 \times 2(0.7365)+1}{3(0.7365)} \right]^{0.7365} \times \frac{0.3644 \times 11,300}{300(8.5-5.0)} \]
\[ Ps = \left[ \frac{2.4 \times 207 \times 2(0.7365)+1}{3(0.7365)} \right]^{0.7365} \times \frac{3.644 \times 11,300}{300(8.5-5.0)} \]
\[ Ps = (141.9 \times 1.11926)^{0.7365} \times 3.9216 \]
\[ Ps = 41.78 \times 3.9216 \]
\[ Ps = 163.8 \text{ psi} \]
6. Pressure loss opposite drill collars:

\[ Ps = 7.7 \times 10^{-5} \times 12.5^{0.8} \times 400^{1.8} \times 24^{0.2} \times 700 \]

\[ (8.5 - 6.5)^3 \times (8.5 + 6.5)^{1.8} \]

Ps = \frac{37056.7}{8 \times 130.9} \approx 35.4 \text{ psi} \\

Total pressure losses: \quad \text{psi} = 163.8 \text{ psi} + 35.4 \text{ psi} \\
\quad \text{psi} = 199.2 \text{ psi} \\

7. Determine equivalent circulating density (ECD), ppg:

ECD, ppg = 199.2 psi \div 0.052 \div 12,000 \text{ ft} + 12.5 \text{ ppg} \\
ECD \quad = 12.82 \text{ ppg} 

9. Fracture Gradient Determination - Surface Application

Method 1: Matthews and Kelly Method

\[ F = \frac{P}{D} + Ki \frac{\sigma}{D} \]

where \( F \) = fracture gradient, psi/ft \quad \quad P = \text{formation pore pressure, psi} \\
\( \sigma \) = matrix stress at point of interest, psi \quad \quad D = \text{depth at point of interest, TVD, ft} \\
Ki = \text{matrix stress coefficient, dimensionless} \\

Procedure:

1. Obtain formation pore pressure, \( P \), from electric logs, density measurements, or from mud logging personnel.

2. Assume 1.0 psi/ft as overburden pressure (S) and calculate \( \sigma \) as follows: \( \sigma = S - P \)

3. Determine the depth for determining Ki by: \( D = \frac{\sigma}{0.535} \)

4. From Matrix Stress Coefficient chart, determine Ki:
4. From Matrix Stress Coefficient chart, determine $\lambda_i$.

Figure 5-1. Matrix stress coefficient chart

5. Determine fracture gradient, psi/ft: 
   \[ F = \frac{P}{D} + K_i \times \frac{\sigma}{D} \]

6. Determine fracture pressure, psi: 
   \[ F, \text{ psi} = F \times D \]

7. Determine maximum mud density, ppg: 
   \[ MW, \text{ ppg} = \frac{F}{0.052} \]

Example: Casing setting depth = 12,000 ft

Formation pore pressure (Louisiana Gulf Coast) = 12.0 ppg

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 = \[ K_i = 0.79 \text{ psi/ft} \]

5. \[ F = \frac{7488}{12,000} + 0.79 \times \frac{4512}{12,000} \]
   \[ F = 0.624 \text{ psi/ft} + 0.297 \text{ psi/ft} \]
   \[ F = 0.92 \text{ psi/ft} \]

6. Fracture pressure, psi = \[ 0.92 \text{ psi/ft} \times 12,000 \text{ ft} \]
   \[ \text{Fracture pressure} = 11,040 \text{ psi} \]

7. Maximum mud density, ppg = \[ \frac{0.92 \text{ psi/ft}}{0.052} \]
   \[ \text{Maximum mud density} = 17.69 \text{ ppg} \]

**Method 2: Ben Eaton Method**

\[ F = \left( \frac{S}{D} \right) - \left( \frac{P_f}{D} \right) + \frac{y}{(1 - y)} + \left( \frac{P_f}{D} \right) \]

where
   \[ \frac{S}{D} = \text{overburden gradient, psi/ft} \]
   \[ \frac{P_f}{D} = \text{formation pressure gradient at depth of interest, psi/ft} \]
   \[ y = \text{Poisson’s ratio} \]

Procedure:
1. Obtain overburden gradient from “Overburden Stress Gradient Chart.”
2. Obtain formation pressure gradient from electric logs, density measurements, or from logging operations.
3. Obtain Poisson’s ratio from “Poisson’s Ratio Chart.”
4. Determine fracture gradient using above equation.
5. Determine fracture pressure, psi: \[ \text{psi} = F \times D \]
6. Determine maximum mud density, ppg: \[ \text{ppg} = F \div 0.052 \]

*Example:* Casing setting depth = 12,000 ft, Formation pore pressure = 12.0 ppg
1. Determine \( S/D \) from chart = depth = 12,000 ft \( S/D = 0.96 \text{ psi/ft} \)
2. \( P_f/D = 12.0 \text{ ppg} \times 0.052 = 0.624 \text{ psi/ft} \)
3. Poisson’s Ratio from chart = 0.47 psi/ft
4. Determine fracture gradient:

\[ F = (0.96 - 0.6243) \left( \frac{0.47}{1 - 0.47} \right) + 0.624 \]

\[ F = 0.336 \times 0.88679 + 0.624 \]

\[ F = 0.29796 + 0.624 \]

\[ F = 0.92 \text{ psi/ft} \]

5. Determine fracture pressure:

\[ \text{psi} = 0.92 \text{ psi/ft} \times 12,000 \text{ ft} \]

\[ \text{psi} = 11,040 \]

6. Determine maximum mud density:

\[ \text{ppg} = \frac{0.92 \text{ psi/ft}}{0.052} \]

\[ \text{ppg} = 17.69 \]

9. 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

Water depth = 2000 ft

Density of seawater = 8.9 ppg

Feet of casing below mud-line = 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:

   \[ \text{Equivalent feet} = \frac{926 \text{ psi}}{0.92 \text{ psi/ft}} \]
2. Determine depth for fracture gradient determination: Depth, ft = 4000 ft + 1006 ft
   Depth = 5006 ft

3. Using Eaton’s Fracture Gradient Chart, determine the fracture gradient at a depth of 5006 ft:

   From chart: Enter chart at a depth of 5006 ft; intersect the 9.0 ppg line; then proceed up and read the fracture gradient at the top of the chart:

   Fracture gradient = 14.7 ppg

4. Determine the fracture pressure: psi = 14.7 ppg x 0.052 x 5006 ft
   psi = 3827

5. Convert the fracture gradient relative to the flow-line: Fc = 3827 psi 0.052 ÷ 6100 ft
   Fc = 12.06 ppg

where Fc is the fracture gradient, corrected for water depth, and air gap.
Directional Drilling Calculations

Directional Survey Calculations

The following are the two most commonly used methods to calculate directional surveys:

1. Angle Averaging Method

North = \( MD \times \sin(\frac{I_1 + I_2}{2}) \times \cos(\frac{A_1 + A_2}{2}) \)

East = \( MD \times \sin(\frac{I_1 + I_2}{2}) \times \sin(\frac{A_1 + A_2}{2}) \)

Vert. = \( MD \times \cos(\frac{I_1 + I_2}{2}) \)

---

Figure 5-3 Eaton’s Fracture gradient chart
2. Radius of Curvature Method

North = \( \frac{MD(\cos I_1 - \cos I_2)(\sin A_2 - \sin A_1)}{(I_2 - I_1)(A_2 - A_1)} \)

East = \( \frac{MD(\cos I_1 - \cos I_2)(\cos A_2 - \cos A_1)}{(I_2 - I_1)(A_2 - A_1)} \)

Vert. = \( \frac{MD(\sin I_2 - \sin I_1)}{(I_2 - I_1)} \)

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:

<table>
<thead>
<tr>
<th>Survey 1</th>
<th>Survey 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth, ft</td>
<td>7482</td>
</tr>
<tr>
<td>Inclination, degrees</td>
<td>4</td>
</tr>
<tr>
<td>Azimuth, degrees</td>
<td>10</td>
</tr>
</tbody>
</table>

Angle Averaging Method:

North = \( 300 \times \sin \left( \frac{4 + 8}{2} \right) \times \cos \left( \frac{10+35}{2} \right) \)

North = \( 300 \times \sin (6) \times \cos (22.5) \)
North = \( 300 \times 0.104528 \times 0.923879 \)
North = 28.97 ft

East = \( 300 \times \sin \left( \frac{4 + 8}{2} \right) \times \sin \left( \frac{10+35}{2} \right) \)

East = \( 300 \times \sin (6) \times \sin (22.5) \)
East = \( 300 \times 0.104528 \times 0.38268 \)
East = 12.0 ft

Vert. = \( 300 \times \cos \left( \frac{4 + 8}{2} \right) \)

Vert. = \( 300 \times \cos (6) \)
Vert. = \( 300 \times 0.99452 \)
Vert. = 298.35 ft
Radius of Curvature Method:

North = \( \frac{300(\cos 4 - \cos 8)(\sin 35 - \sin 10)}{(8 - 4)(35 - 10)} \)

North = \( \frac{300 (0.99756 - 0.99026)(0.57357 - 0.173648)}{4 \times 25} \)

North = 0.874629 \div 100
North = 0.008746 \times 57.3^2
North = 28.56 \text{ ft}

East = \( \frac{300(\cos 4 - \cos 8)(\cos 10 - \cos 35)}{(8 - 4)(35 - 10)} \)

East = \( \frac{300 (0.99756 - 0.99026)(0.9848 - 0.81915)}{4 \times 25} \)

East = \( \frac{300 (0.0073)(0.16565)}{100} \)
East = 0.36277 \div 100
East = 0.0036277 \times 57.3^2
East = 11.91 \text{ ft}

Vert. = \( \frac{300 (\sin 8 - \sin 4)}{(8 - 4)} \)

Vert. = \( \frac{300 (0.13917 - 0.06976)}{(8 - 4)} \)

Vert. = 300 \times 0.069414 \div 4
Vert. = 300 \times 0.069414 \div 4
Vert. = 5.20605 \times 57.3
Vert. = 298.3 \text{ ft}

**Deviation/Departure Calculation**

Deviation is defined as departure of the wellbore from the vertical, measured by the horizontal distance from the rotary table to the target. The amount of deviation is a function of the drift angle (inclination) and hole depth.
The following diagram illustrates how to determine the deviation/departure:

**Figure 5-4. Deviation/Departure**

To calculate the deviation/departure (CD), ft:

\[ CD, \text{ ft} = \sin I \times BD \]

*Example:* Kick off point (KOP) is a distance 2000 ft from the surface. MD is 8000 ft. Hole angle (inclination) is 20 degrees. Therefore the distance from KOP to MD = 6000 ft (BD):

\[ CD, \text{ ft} = \sin 20 \times 6000 \text{ ft} \]
\[ CD = 2052 \text{ ft} \]

From this calculation, the measured depth (MD) is 2052 ft away from vertical.

**Dogleg Severity Calculation**

**Method 1**

Dogleg severity (DLS) is usually given in degrees/100 ft. The following formula provides dogleg severity in degrees/100 ft and is based on the Radius of Curvature Method:

\[ DLS = \{ \cos^{-1} \left[ (\cos I_1 \times \cos I_2) + (\sin I_1 \times \sin I_2) \times \cos (A_2 - A_1) \right] \} \times \left( \frac{100}{CL} \right) \]

For metric calculation, substitute \( \times \left( \frac{30}{CL} \right) \) i.e.

\[ DLS = \{ \cos^{-1} \left[ (\cos I_1 \times \cos I_2) + (\sin I_1 \times \sin I_2) \times \cos (A_2 - A_1) \right] \} \times \left( \frac{30}{CL} \right) \]

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
- \(^{\text{Azimuth}} = \text{azimuth change between surveys, degrees}\)
Formulas and Calculations

Example:

<table>
<thead>
<tr>
<th></th>
<th>Survey 1</th>
<th>Survey 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth, ft</td>
<td>4231</td>
<td>4262</td>
</tr>
<tr>
<td>Inclination, degrees</td>
<td>13.5</td>
<td>14.7</td>
</tr>
<tr>
<td>Azimuth, degrees</td>
<td>N 10 E</td>
<td>N 19 E</td>
</tr>
</tbody>
</table>

DLS = \[ \cos^{-1} \left[ \left( \cos 13.5 \times \cos 14.7 \right) + \left( \sin 13.5 \times \sin 14.7 \times \cos (19 - 10) \right) \right] \times \left( \frac{100}{31} \right) \\
DLS = \left[ \cos^{-1} \left( \left( 0.9723699 \times 0.9672677 \right) + \left( 0.2334453 \times 0.2537579 \times 0.9876883 \right) \right) \right] \times \left( \frac{100}{31} \right) \\
DLS = \left[ \cos^{-1} \left( 0.940542 + 0.0585092 \right) \right] \times \left( \frac{100}{31} \right) \\
DLS = 2.4960847 \times \left( \frac{100}{31} \right) \\
DLS = 8.051886 degrees/100 ft

Method 2

This method of calculating dogleg severity is based on the tangential method:

DLS = \[ \frac{100}{L \left[ \sin I_1 \times \sin I_2 \left( \sin A_1 \times \sin A_2 + \cos A_1 \times \cos A_2 \right) + \cos I_1 \times \cos I_2 \right]} \]

where  
DLS = dogleg severity, degrees/100 ft 
L = course length, ft 
I_1, I_2 = inclination (angle) at upper and lower surveys, degrees 
A_1, A_2 = direction at upper and lower surveys, degrees

Example:

<table>
<thead>
<tr>
<th></th>
<th>Survey 1</th>
<th>Survey 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
<td>4231</td>
<td>4262</td>
</tr>
<tr>
<td>Inclination, degrees</td>
<td>13.5</td>
<td>14.7</td>
</tr>
<tr>
<td>Azimuth, degrees</td>
<td>N 10 E</td>
<td>N 19 E</td>
</tr>
</tbody>
</table>

DLS = \[ \frac{100}{31 \left[ \sin 13.5 \times \sin 14.7 \left( \sin 10 \times \sin 19 \right) + \left( \cos 10 \times \cos 119 \right) + \left( \cos 13.5 \times \cos 14.7 \right) \right]} \]

DLS = \[ \frac{100}{30.969} \]
DLS = 3.229 degrees/100 ft

Available Weight on Bit in Directional Wells

A directionally drilled well requires that a correction be made in total drill collar weight because only a portion of the total weight will be available to the bit:

P = W \times \cos I

where  
P = partial weight available for bit 
Cos = cosine 
I = degrees inclination (angle) 
W = total weight of collars
Example: \[ W = 45,000 \text{ lb} \quad I = 25 \text{ degrees} \]

\[ P = 45,000 \times \cos 25 \]
\[ P = 45,000 \times 0.9063 \]
\[ P = 40,784 \text{ lb} \]

Thus, the available weight on bit is 40,784 lb.

**Determining True Vertical Depth**

The following is a simple method of correcting for the TVD on directional wells. This calculation will give 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:

\[ \text{TVD}_2 = \cos I \times \text{CL} + \text{TVD}_1 \]

where \( \text{TVD}_2 = \) new true vertical depth, ft  
\( \text{TVD}_1 = \) last true vertical depth, ft  
\( \text{CL} = \) course length — number of feet since last survey  
\( \cos = \) cosine

Example: 
TVD (last survey) = 8500 ft  
Deviation angle = 40 degrees  
Course length = 30 ft

Solution: 
\[ \text{TVD}_2 = \cos 40 \times 30 \text{ ft} + 8500 \text{ ft} \]
\[ \text{TVD}_2 = 0.766 \times 30 \text{ ft} + 8500 \text{ ft} \]
\[ \text{TVD}_2 = 22.98 \text{ ft} + 8500 \text{ ft} \]
\[ \text{TVD}_2 = 8522.98 \text{ ft} \]

**11. Miscellaneous Equations and Calculations**

**Surface Equipment Pressure Losses**

\[ \text{SEpl} = C \times MW \times \left( \frac{Q}{100} \right)^{1.86} \]

where \( \text{SEpl} = \) surface equipment pressure loss, psi  
\( Q = \) circulation rate, gpm  
\( C = \) friction factor for type of surface equipment  
\( W = \) mud weight, ppg

<table>
<thead>
<tr>
<th>Type of Surface Equipment</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.0</td>
</tr>
<tr>
<td>2</td>
<td>0.36</td>
</tr>
<tr>
<td>3</td>
<td>0.22</td>
</tr>
<tr>
<td>4</td>
<td>0.15</td>
</tr>
</tbody>
</table>
Example: Surface equipment type = 3  C = 0.22
Mud weight = 11.8 ppg  Circulation rate = 350 gpm

\[ SEpl = 0.22 \times 11.8 \times (350)^{1.86} \]
\[ SEpl = 2.596 \times (35)^{1.86} \]
\[ SEpl = 2.596 \times 10.279372 \]
\[ SEpl = 26.69 \text{ psi} \]

Drill Stem Bore Pressure Losses

\[ P = \frac{0.000061 \times MW \times L \times Q^{1.86}}{d^{4.86}} \]

where  
\( P \) = drill stem bore pressure losses, psi  
\( MW \) = 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.

\[ P = \frac{0.000061 \times 10.9 \times 6500 \times (350)^{1.86}}{4.276^{4.86}} \]
\[ P = 4.32185 \times 53946.909 \]
\[ P = 199.89 \text{ psi} \]

Annular Pressure Losses

\[ P = (1.4327 \times 10^{-7}) \times MW \times L \times V^{2} \]

\[ \frac{Dh}{Dp} \]

where  
\( P \) = annular pressure losses, psi  
\( MW \) = mud weight, ppg  
\( L \) = length, ft  
\( V \) = annular velocity, ft/mm  
\( Dh \) = 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.

\[ v = \frac{24.5 \times 350}{8.5^{2} - 5.0^{2}} \]
\[ v = 8575 \]
\[ v = 47.25 \]
\[ v = 181 \text{ ft/min} \]
Determine annular pressure losses, psi:  
\[ P = \left( 1.4327 \times 10^{-7} \times 12.5 \times 6500 \times 181^2 \right) \frac{\text{8.5} - \text{5.0}}{3.5} \]
\[ P = 381.36 \]
\[ P = 108.96 \text{ psi} \]

**Pressure Loss Through Common Pipe Fittings**

\[ P = \frac{K \times MW \times Q^2}{12,031 \times A^2} \]

where  
- \( P \) = pressure loss through common pipe fittings  
- \( A \) = area of pipe, sq in.  
- \( K \) = loss coefficient (See chart below)  
- \( MW \) = weight of fluid, ppg  
- \( Q \) = circulation rate, gpm

**List of Loss Coefficients (K)**

- \( K = 0.42 \) for 45 degree ELL  
- \( K = 1.80 \) for tee  
- \( K = 0.19 \) for open gate valve  
- \( K = 0.90 \) for 90 degree ELL  
- \( K = 1.80 \) for return bend  
- \( K = 2.20 \) for return bend  
- \( K = 2.20 \) for return bend  
- \( K = 0.85 \) for open butterfly valve

**Example:**  
- \( K = 0.90 \) for 90 degree ELL  
- \( MW = 8.33 \) ppg (water)  
- \( Q = 100 \) gpm  
- \( A = 12.5664 \) sq. in. (4.0 in. ID pipe)

\[ P = 0.90 \times 8.33 \times 100^2 \]
\[ 12,031 \times 12.5664^2 \]
\[ P = 74970 \]
\[ 1899868.3 \]
\[ P = 0.03946 \text{ psi} \]

**Minimum Flow-rate for PDC Bits**

Minimum flow-rate, gpm = 12.72 x bit diameter, in.\(^{1.47}\)

**Example:**  
Determine the minimum flow-rate for a 12-1/4 in. PDC bit:

Minimum flow-rate, gpm = 12.72 x 12.25\(^{1.47}\)  
Minimum flow-rate, gpm = 12.72 x 39.77  
Minimum flow-rate = 505.87 gpm
Critical RPM: RPM to Avoid Due to Excessive Vibration (Accurate to Approximately 15%)

Critical RPM = \( \frac{33055 \times \sqrt{OD, in.^2 + ID, in.^2}}{L, \text{ ft}^2} \)

Example:  
L = length of one joint of drill pipe = 31 ft  
OD = drill pipe outside diameter = 5.0 in.  
ID = drill pipe inside diameter = 4.276 in.

Critical RPM = \( \frac{33055 \times \sqrt{5.0^2 + 4.276^2}}{312} \)

Critical RPM = \( \frac{33055 \times \sqrt{43.284}}{961} \)

Critical RPM = 34.3965 x 6.579  
Critical RPM = 226.296

NOTE: As a rule of thumb, for 5.0 in. drill pipe, do not exceed 200 RPM at any depth.
References

### APPENDIX A

#### Table A-1
CAPACITY AND DISPLACEMENT
(English System)

<table>
<thead>
<tr>
<th>Size OD in.</th>
<th>Size ID in.</th>
<th>WEIGHT lb/ft</th>
<th>CAPACITY bbl/ft</th>
<th>DISPLACEMENT bbl/ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>2-3/8</td>
<td>1.815</td>
<td>6.65</td>
<td>0.01730</td>
<td>0.00320</td>
</tr>
<tr>
<td>2-7/8</td>
<td>2.150</td>
<td>10.40</td>
<td>0.00449</td>
<td>0.00354</td>
</tr>
<tr>
<td>3-1/2</td>
<td>2.764</td>
<td>13.30</td>
<td>0.00742</td>
<td>0.00448</td>
</tr>
<tr>
<td>3-1/2</td>
<td>2.602</td>
<td>15.50</td>
<td>0.00658</td>
<td>0.00532</td>
</tr>
<tr>
<td>4</td>
<td>3.340</td>
<td>14.00</td>
<td>0.01084</td>
<td>0.00471</td>
</tr>
<tr>
<td>4-1/2</td>
<td>3.826</td>
<td>16.60</td>
<td>0.01422</td>
<td>0.00545</td>
</tr>
<tr>
<td>4-1/2</td>
<td>3.640</td>
<td>20.00</td>
<td>0.01287</td>
<td>0.00680</td>
</tr>
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<td>0.02294</td>
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#### Table A-2
HEAVY WEIGHT DRILL PIPE AND DISPLACEMENT

<table>
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<tr>
<th>Size OD in.</th>
<th>Size ID in.</th>
<th>WEIGHT lb/ft</th>
<th>CAPACITY bbl/ft</th>
<th>DISPLACEMENT bbl/ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-1/2</td>
<td>2.0625</td>
<td>25.3</td>
<td>0.00421</td>
<td>0.00921</td>
</tr>
<tr>
<td>4</td>
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</table>

Additional capacities, bbl/ft, displacements, bbl/ft and weight, lb/ft can be determined from the following:

- Capacity, bbl/ft = \( \frac{\text{ID, in.}^2}{1029.4} \)
- Displacement, bbl/ft = \( \frac{\text{DH, in.} - \text{DP, in.}^2}{1029.4} \)
- Weight, lb/ft = Displacement, bbl/ft \times 2747 \text{ lb/bbl}
### Table A-3
CAPACITY AND DISPLACEMENT
(Metric System)
DRILL PIPE

<table>
<thead>
<tr>
<th>Size OD</th>
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<th>CAPACITY</th>
<th>DISPLACEMENT</th>
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<td>in.</td>
<td>lb/ft</td>
<td>ltrs/ft</td>
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## DRILL COLLAR CAPACITY AND DISPLACEMENT

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<th>3¼&quot;</th>
<th>3½&quot;</th>
<th>3¾&quot;</th>
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1. **Tank Capacity Determinations**

**Rectangular Tanks with Flat Bottoms**

![Diagram of a rectangular tank with flat bottom]

Volume, bbl = \( \frac{\text{length, ft} \times \text{width, ft} \times \text{depth, ft}}{5.61} \)

*Example 1:* Determine the total capacity of a rectangular tank with flat bottom using the following data:

- Length = 30 ft
- Width = 10 ft
- Depth = 8 ft

Volume, bbl = \( \frac{30 \times 10 \times 8}{5.61} \)

Volume = 427.84 bbl

*Example 2:* Determine the capacity of this same tank with only 5-1/2 ft of fluid in it:

Volume, bbl = \( \frac{30 \times 10 \times 5.5}{5.61} \)

Volume = 294.12 bbl

**Rectangular Tanks with Sloping Sides:**

![Diagram of a rectangular tank with sloping sides]

Volume bbl = \( \frac{\text{length, ft} \times (\text{depth, ft} (\text{top}) + \text{width, ft} + \text{top}^2))}{5.62} \)

*Example:* Determine the total tank capacity using the following data:

- Length = 30 ft
- Width, (top) = 10 ft
- Depth = 8 ft
- Width\(_2\), (bottom) = 6 ft
Volume, bbl = \(\frac{30 \text{ ft} \times [8 \text{ ft} \times (10 \text{ ft} + 6 \text{ ft})]}{5.62}\)

Volume, bbl = \(\frac{30 \text{ ft} \times 128}{5.62}\)

Volume = 683.3 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 \hspace{1cm} Diameter = 10 ft

**NOTE:** The radius (r) is one half of the diameter: \(r = \frac{10}{2} = 5\)

Volume, bbl = \(\frac{3.14 \times 5^2 \times 15 \text{ ft}}{5.61}\)

Volume bbl = 1177.5

Volume = 209.89 bbl

**Tapered Cylindrical Tanks:**

a) Volume of cylindrical section: \(V_c = 0.1781 \times 3.14 \times R_c^2 \times H_c\)

b) Volume of tapered section: \(V_t = 0.059 \times 3.14 \times H_t \times (R_c^2 + R_b^2 + R_b R_c)\)
where \( V_c = \text{volume of cylindrical section, bbl} \)
\( R_c = \text{radius of cylindrical section, ft} \)
\( H_c = \text{height of cylindrical section, ft} \)
\( V_t = \text{volume of tapered section, bbl} \)
\( H_t = \text{height of tapered section, ft} \)
\( R_b = \text{radius at bottom, ft} \)

Example: Determine the total volume of a cylindrical tank with the following dimensions:

- Height of cylindrical section = 5.0 ft
- Radius of cylindrical section = 6.0 ft
- Height of tapered section = 10.0 ft
- Radius at bottom = 1.0 ft

Solution:

a) Volume of the cylindrical section:
\[
V_c = 0.1781 \times 3.14 \times 6.02 \times 5.0
\]
\[
V_c = 100.66 \text{ bbl}
\]

b) Volume of tapered section:
\[
V_t = 0.059 \times 3.14 \times 10 \times (6^2 + 1^2 + 1 \times 6)
\]
\[
V_t = 1.8526 \times 36 + 1 + 6
\]
\[
V_t = 1.8526 \times 43
\]
\[
V_t = 79.66 \text{ bbl}
\]

c) Total volume:
\[
bbl = 100.66 \text{ bbl} + 79.66 \text{ bbl}
\]
\[
bbl = 180.32
\]

**Horizontal Cylindrical Tank:**

a) Total tank capacity:
\[
\text{Volume, bbl} = \frac{3.14 \times r^2 \times L}{42} (7.48)
\]

b) Partial volume;
\[
\text{Vol. ft}^3 = L \left[ 0.017453 \times r^2 \times \cos^{-1} (r - h) - \text{sq. root} (2hr - h^2 (r - h)) \right]
\]

*Example I:* Determine the total volume of the following tank;

- Length = 30 ft
- Radius = 4 ft

a) Total tank capacity;
\[
\text{Volume, bbl} = \frac{3.14 \times 42^2 \times 30 \times 7.48}{48}
\]
\[
\text{Volume, bbl} = 11273.856
\]
\[
\text{Volume} = 234.87 \text{ bbl}
\]
Example 2: Determine the volume if there are only 2 feet of fluid in this tank; (h = 2 ft)

Volume, \( \text{ft}^3 \) = 30 \([0.017453 \times 4^2 \times \cos^{-1} (4 - (2÷4)) - \text{sq. root} \ (2 \times 2 \times 4 - 2^2) \times (4 - 2)]\)

Volume, \( \text{ft}^3 \) = 30 \([0.279248 \times \cos^{-1} (0.5) - \text{sq. root} \ 12 \times (2)]\)

Volume, \( \text{ft}^3 \) = 30 \((0.279248 \times 60 - 3.464 \times 2)\)

Volume, \( \text{ft}^3 \) = 30 \times 9.827

Volume \( = 294 \text{ ft}^3 \)

To convert volume, \( \text{ft}^3 \), to barrels, multiply by 0.1781.
To convert volume, \( \text{ft}^3 \), to gallons, multiply by 7.4805.

Therefore, 2 feet of fluid in this tank would result in;

Volume, bbl \( = 294 \text{ ft}^3 \times 0.1781\)

Volume \( = 52.36 \text{ bbl} \)

NOTE: This is only applicable until the tank is half full \( (r - h) \). After that, calculate total volume of the tank and subtract the empty space.

The empty space can be calculated by \( h = \text{height of empty space} \).
## APPENDIX B

### Conversion Factors

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<th>TO</th>
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| **Circulation Rate**    |                 |                |
| Barrels/min             | Gallons/min     | 42.0           |
| Cubic feet/min          | Cubic meters/sec| 4.72 x 10^-4   |
| Cubic feet/min          | Gallons/min     | 7.48           |
| Cubic feet/mm           | Litres/min      | 28.32          |
| Cubic meters/sec        | Gallons/min     | 15850          |
| Cubic meters/sec        | Cubic feet/min  | 2118           |
| Cubic meters/sec        | Litres/min      | 60000          |
| Gallons/min             | Barrels/ruin    | 0.0238         |
| Gallons/min             | Cubic feet/min  | 0.134          |
| Gallons/min             | Litres/min      | 3.79           |
| Gallons/min             | Cubic meters/sec| 6.309 x 10^5   |
| Litres/min              | Cubic meters/sec| 1.667 x 10^5   |
| Litres/min              | Cubic feet/min  | 0.0353         |
| Litres/min              | Gallons/min     | 0.264          |

| **Impact Force**        |                 |                |
| Pounds                  | Dynes           | 4.45 x 10^-5   |
| Pounds                  | Kilograms       | 0.454          |
| Pounds                  | Newtons         | 4.448          |
| Dynes                   | Pounds          | 2.25 x 10^-6   |
## Formulas and Calculations

### TO CONVERT FROM

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### Length

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<td>Meters</td>
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<td>3.281</td>
</tr>
</tbody>
</table>

### Mud Weight

<table>
<thead>
<tr>
<th>Pounds/gallon</th>
<th>Pounds/cu ft</th>
<th>7.48</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pounds/gallon</td>
<td>Specific gravity</td>
<td>0.120</td>
</tr>
<tr>
<td>Pounds/gallon</td>
<td>Grams/cu cm</td>
<td>0.1198</td>
</tr>
<tr>
<td>Grams/cu cm</td>
<td>Pounds/gallon</td>
<td>8.347</td>
</tr>
<tr>
<td>Pounds/cu ft</td>
<td>Pounds/gallon</td>
<td>0.134</td>
</tr>
<tr>
<td>Specific gravity</td>
<td>Pounds/gallon</td>
<td>8.34</td>
</tr>
</tbody>
</table>

### Power

<table>
<thead>
<tr>
<th>Horsepower</th>
<th>Horsepower (metric)</th>
<th>1.014</th>
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<tbody>
<tr>
<td>Horsepower</td>
<td>Kilowatts</td>
<td>0.746</td>
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<tr>
<td>Horsepower</td>
<td>Foot pounds/sec</td>
<td>550</td>
</tr>
<tr>
<td>Horsepower (metric)</td>
<td>Horsepower</td>
<td>0.986</td>
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<tr>
<td>Horsepower (metric)</td>
<td>Foot pounds/sec</td>
<td>542.5</td>
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<tr>
<td>Kilowatts</td>
<td>Horsepower</td>
<td>1.341</td>
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<tr>
<td>Foot pounds/sec</td>
<td>Horsepower</td>
<td>0.00181</td>
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### Pressure

<table>
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<th>Atmospheres</th>
<th>Pounds/sq. in.</th>
<th>14.696</th>
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<tbody>
<tr>
<td>Atmospheres</td>
<td>Kgs/sq. cm</td>
<td>1.033</td>
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<tr>
<td>Atmospheres</td>
<td>Pascals</td>
<td>$1.013 \times 10^3$</td>
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<tr>
<td>Kilograms/sq. cm</td>
<td>Atmospheres</td>
<td>0.9678</td>
</tr>
<tr>
<td>Kilograms/sq. cm</td>
<td>Pounds/sq. in.</td>
<td>14.223</td>
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<tr>
<td>Kilograms/sq. cm</td>
<td>Atmospheres</td>
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<tr>
<td>Pounds/sq. in.</td>
<td>Atmospheres</td>
<td>0.680</td>
</tr>
<tr>
<td>Pounds/sq. in.</td>
<td>Kgs/sq. cm</td>
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<tr>
<td>Pounds/sq. in.</td>
<td>Pascals</td>
<td>$6.894 \times 10^3$</td>
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## Formulas and Calculations

<table>
<thead>
<tr>
<th>TO CONVERT FROM</th>
<th>TO</th>
<th>MULTIPLY BY</th>
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<tbody>
<tr>
<td><strong>Velocity</strong></td>
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<td></td>
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<tr>
<td>Feet/sec</td>
<td>Meters/sec</td>
<td>0.305</td>
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<tr>
<td>Feet/mm</td>
<td>Meters/sec</td>
<td>5.08 x 10^3</td>
</tr>
<tr>
<td>Meters/sec</td>
<td>Feet/mm</td>
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<tr>
<td>Meters/sec</td>
<td>Feet/sec</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Volume</strong></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Barrels</td>
<td>Gallons</td>
<td>42</td>
</tr>
<tr>
<td>Cubic centimetres</td>
<td>Cubic feet</td>
<td>3.531 x 10^3</td>
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<tr>
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<td>Cubic inches</td>
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<td>Cubic centimetres</td>
<td>Cubic meters</td>
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<tr>
<td>Cubic centimetres</td>
<td>Gallons</td>
<td>2.642 x 10^{-4}</td>
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<tr>
<td>Cubic centimetres</td>
<td>Litters</td>
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<td>Cubic feet</td>
<td>Cubic centimetres</td>
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<tr>
<td>Cubic feet</td>
<td>Cubic inches</td>
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<tr>
<td>Cubic feet</td>
<td>Cubic meters</td>
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<tr>
<td>Cubic feet</td>
<td>Gallons</td>
<td>7.48</td>
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<tr>
<td>Cubic feet</td>
<td>Litters</td>
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<tr>
<td>Cubic inches</td>
<td>Cubic centimetres</td>
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<tr>
<td>Cubic inches</td>
<td>Cubic feet</td>
<td>5.787 x 10^{-4}</td>
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<tr>
<td>Cubic inches</td>
<td>Cubic meters</td>
<td>1.639 x 10^{-5}</td>
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<tr>
<td>Cubic inches</td>
<td>Gallons</td>
<td>4.329 x 10^{-3}</td>
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<tr>
<td>Cubic inches</td>
<td>Litres</td>
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<tr>
<td>Cubic meters</td>
<td>Cubic centimetres</td>
<td>10^6</td>
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<td>Cubic meters</td>
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<tr>
<td>Gallons</td>
<td>Cubic inches</td>
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<tr>
<td>Gallons</td>
<td>Cubic meters</td>
<td>3.785 x 10^{-4}</td>
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<tr>
<td>Gallons</td>
<td>Litres</td>
<td>3.785</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Weight</strong></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Pounds</td>
<td>Tons (metric)</td>
<td>4.535 x 10^4</td>
</tr>
<tr>
<td>Tons (metric)</td>
<td>Pounds</td>
<td>2205</td>
</tr>
<tr>
<td>Tons (metric)</td>
<td>Kilograms</td>
<td>1000</td>
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