

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

psi/ft = mud weight, ppg x 0.052 *Example:* 12.0 ppg fluid

psi/ft = 12.0 ppg x 0.052

psi/ft = 0.624

Pressure gradient, psi/ft, using mud weight, lb/ft³

psi/ft = mud weight, lb/ft³ x 0.006944 *Example:* 100 lb/ft³ fluid

psi/ft = 100 lb/ft³ x 0.006944

psi/ft = 0.6944

OR

psi/ft = mud weight, lb/ft³ ÷ 144 *Example:* 100 lb/ft³ fluid

psi/ft = 100 lb/ft³ ÷ 144

psi/ft = 0.6944

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

psi/ft = mud weight, SG x 0.433 *Example:* 1.0 SG fluid

psi/ft = 1.0 SG x 0.433

psi/ft = 0.433

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

ppg = pressure gradient, psi/ft ÷ 0.052 *Example:* 0.4992 psi/ft

ppg = 0.4992 psi/ft ÷ 0.052

ppg = 9.6

Convert pressure gradient, psi/ft, to mud weight, lb/ft³

lb/ft³ = pressure gradient, psi/ft ÷ 0.006944 *Example:* 0.6944 psi/ft

lb/ft³ = 0.6944 psi/ft ÷ 0.006944

lb/ft³ = 100

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

SG = pressure gradient, psi/ft 0.433 *Example:* 0.433 psi/ft

SG 0.433 psi/ft ÷ 0.433

SG = 1.0

2. Hydrostatic Pressure (HP)

Hydrostatic pressure using ppg and feet as the units of measure

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

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

HP = 13.5 ppg x 0.052 x 12,000 ft

HP = 8424 psi

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

HP = psi/ft x true vertical depth, ft

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

HP = 0.624 psi/ft x 8500 ft

HP = 5304 psi

Hydrostatic pressure, psi, using mud weight, lb/ft³

HP = mud weight, lb/ft³ x 0.006944 x TVD, ft

Example: mud weight = 90 lb/ft³ true vertical depth = 7500 ft

HP = 90 lb/ft³ x 0.006944 x 7500 ft

HP = 4687 psi

Hydrostatic pressure, psi, using meters as unit of depth

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

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

HP = 12.2 ppg x 0.052 x 3700 x 3.281

HP = 7,701 psi

3. Converting Pressure into Mud Weight

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

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

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

mud, ppg = 2600 psi ÷ 0.052 ÷ 5000 ft

mud = 10.0 ppg

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

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

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

mud wt, ppg = 3583 psi ÷ 0.052 ÷ 2000 m ÷ 3.281

mud wt = 10.5 ppg

4. Specific Gravity (SG)

Specific gravity using mud weight, ppg

SG = mud weight, ppg ÷ 8.33

Example: 15.0 ppg fluid

SG = 15.0 ppg ÷ 8.33

SG = 1.8

Specific gravity using pressure gradient, psi/ft

SG = pressure gradient, psi/ft ÷ 0.433

Example: pressure gradient = 0.624 psi/ft

SG = 0.624 psi/ft ÷ 0.433

SG = 1.44

Specific gravity using mud weight, lb/ft³

SG = mud weight, lb/ft³ ÷ 62.4

Example: Mud weight = 120 lb/ft³

SG = 120 lb/ft³ ÷ 62.4

SG = 1.92

Convert specific gravity to mud weight, ppg

mud weight, ppg = specific gravity × 8.33

Example: specific gravity = 1.80

mud wt, ppg = 1.80 × 8.33

mud wt = 15.0 ppg

Convert specific gravity to pressure gradient, psi/ft

psi/ft = specific gravity × 0.433

Example: specific gravity = 1.44

psi/ft = 1.44 × 0.433

psi/ft = 0.624

Convert specific gravity to mud weight, lb/ft³

lb/ft³ = specific gravity × 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

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

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

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

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

$$\text{ppg} = 1140 \text{ psi} \div 0.052 \div 4000 \text{ ft} + 10.0 \text{ ppg} \quad \text{ppg} = 15.48$$

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 = $95 \div 100 = 0.95$

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

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

Formula 2

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

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

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

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

$$PO, \text{ gpm} = 1385.4456 \times 0.00411 \times 80$$

$$PO = 455.5 \text{ gpm}$$

Duplex Pump Formula 1

$$0.000324 \times (\text{Liner Diameter, in.})^2 \times (\text{stroke length, in.}) = \underline{\hspace{2cm}} \text{ bbl/stk}$$

$$-0.000162 \times (\text{Liner Diameter, in.})^2 \times (\text{stroke length, in.}) = \underline{\hspace{2cm}} \text{ bbl/stk}$$

$$\text{Pump output @ 100\% eff} = \underline{\hspace{2cm}} \text{ bbl/stk}$$

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

$$0.000324 \times 5.5^2 \times 14 = 0.137214 \text{ bbl/stk}$$

$$-0.000162 \times 2.0^2 \times 14 = \underline{0.009072} \text{ bbl/stk}$$

$$\text{pump output 100\% eff} = 0.128142 \text{ bbl/stk}$$

Adjust pump output for 85% efficiency:

$$\text{Decimal equivalent} = 85 \div 100 = 0.85$$

$$PO @ 85\% = 0.128142 \text{ bbl/stk} \times 0.85$$

$$PO @ 85\% = 0.10892 \text{ bbl/stk}$$

Formula 2

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

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.:

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

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

$$PO @ 100\% = 0.128142 \text{ bbl/stk}$$

Adjust pump output for 85% efficiency:

$$PO @ 85\% = 0.128142 \text{ bbl/stk} \times 0.85$$

$$PO @ 85\% = 0.10892 \text{ bbl/stk}$$

8. Annular Velocity (AV)

Annular velocity (AV), ft/min

Formula 1

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

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

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

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

Formula 2

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

where Q = circulation rate, gpm, D_h = inside diameter of casing or hole size, in.

D_p = outside diameter of pipe, tubing or collars, in.

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

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

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

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

Formula 3

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

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

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

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

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

Annular velocity (AV), ft/sec

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

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

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

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

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

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

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

where AV = desired annular velocity, ft/min

Dh = inside diameter of casing or hole size, in.

Dp = outside diameter of pipe, tubing or collars, in.

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

$$PO = \frac{120 (12.25^2 - 45^2)}{24.5}$$

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

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

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

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 in. Dp = 4-1/2 in. pump output = 0.136 bbl/stk

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

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

$$SPM = 111.3$$

9. Capacity Formulas

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

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

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

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

Annular capacity = 0.12149 bbl/ft

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

Example: Hole size (Dh) = 12-1/4 in. Drill pipe OD (Dp) = 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 = $\frac{Dh^2 - Dp^2}{24.51}$

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

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

Annular capacity = 5.1 gal/ft

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

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

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

Annular capacity, ft/gal = 0.19598 ft/gal

e) Annular capacity, ft³/linft = $\frac{Dh^2 - Dp^2}{...}$

183.35

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

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

$$\text{Annular capacity} = 0.682097 \text{ ft}^3/\text{linft}$$

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

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

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

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

Annular capacity between casing and multiple strings of tubing

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

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

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.

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

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

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

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

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

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.

$$\text{Annular capacity ft/bbl} = \frac{1029.4}{}$$

$$6.184^2 - (2.375^2 + 2.375^2)$$

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

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

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

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

Example: Using two tubing strings of different size:

Dh = casing — 7.0 in. — 29 lb/ft ID = 6.184 in.

T₁ = tubing No. 1 — 2-3/8 in. OD = 2.375 in.

T₂ = 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.

T₁ = tubing No. 1 — 2-3/8 in. OD = 2.375 in.

T₂ = tubing No. 2 — 3-1/2 in. OD = 3.5 in.

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

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

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

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

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

Example: Using three strings of tubing:

Dh = casing — 9-5/8 in. — 47 lb/ft ID = 8.681 in.

T₁ = tubing No. 1 — 3-1/2 in. — OD = 3.5 in.

T₂ = tubing No. 2 — 3-1/2 in. — OD = 3.5 in.

T₃ = tubing No. 3 — 3-1/2 in. — OD = 3.5 in.

$$\text{Annular capacity} = \frac{8.6812 - (3.5^2 + 3.5^2 + 3.5^2)}{183.35}$$

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

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

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

$$\text{Annular capacity, linft/ft}^3 = \frac{183.35}{Dh_2 - [(T_1)^2 + (T_2)^2 + (T_3)^2]}$$

Example: Using three strings tubing of same size:

Dh = casing 9-5/8 in. 47 lb/ft ID = 8.681 in.

T₁ = tubing No. 1 3-1/2 in. OD = 3.5 in.

T₂ = tubing No. 2 3-1/2 in. OD = 3.5 in.

T₃ = 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 = $\frac{ID \text{ in.}^2}{1029.4}$ *Example:* Determine the capacity, bbl/ft, of a 12-1/4 in. hole:

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

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

b) Capacity, ft/bbl = $\frac{1029.4}{Dh^2}$ *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, ft³/linft = $\frac{ID^2}{18135}$ *Example:* Determine the capacity, ft³/linft, for a 6.0 in. hole:-

$$18135$$

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

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

f) Capacity, linft/ft³ = $\frac{183.35}{ID, \text{ in.}^2}$ *Example:* Determine the capacity, linft/ft³, for a 6.0 in. hole:

$$ID, \text{ in.}^2$$

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

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

Amount of cuttings drilled per foot of hole drilled

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

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

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

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

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

$$\text{Barrels} = 0.1166213$$

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

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

144

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

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

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

c) Total solids generated:

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

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

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

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

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

10. Control Drilling

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

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

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

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

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

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

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

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

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

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

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

$$\text{Step 1} \quad \text{Barrels} = \frac{\text{number of stands pulled} \times \text{average length per stand, ft} \times \text{pipe displacement displaced bbl/ft}}$$

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 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	

HP decrease = 133.52 psi

13. Loss of Overbalance Due to Falling Mud Level

Feet of pipe pulled DRY to lose overbalance

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

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

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

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

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

$$\text{Ft} = 2334$$

Feet of pipe pulled WET to lose overbalance

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

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

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

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

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

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

$$\text{Feet} = 516.8$$

14. Formation Temperature (FT)

FT, °F = (ambient surface temperature, °F) + (temp. increase °F per ft of depth x 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:

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

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

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

15. Hydraulic Horsepower (HHP)

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

where HHP = hydraulic horsepower P = circulating pressure, psi

Q = circulating rate, gpm

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

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

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

$$\text{HHP} = 894.98$$

16. Drill Pipe/Drill Collar Calculations

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

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

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

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

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

Drill collar OD = 8.0 in.

Drill collar ID = 2-13/16 in.

Convert 13/16 to decimal equivalent: $13 \div 16 = 0.8125$

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 = $\frac{56.089844}{1029.4}$

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.

$$\text{Weight, lb/ft} = (8.0^2 - 2.8125^2) \times 2.66$$

$$\text{Weight, lb/ft} = 56.089844 \times 2.66$$

$$\text{Weight} = 149.19898 \text{ lb/ft}$$

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 = 2.8125 in.

$$\text{Weight, lb/ft} = (8.0^2 - 2.8125^2) \times 2.56$$

$$\text{Weight, lb/ft} = 56.089844 \times 2.56$$

Weight = 143.59 lb/ft

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

Basic formula

New circulating pressure, psi = present circulating pressure, psi X (new pump rate, spm ÷ old pump rate, spm)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 (30 spm ÷ 60 spm)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 “2” is a rounded-off number. To determine the exact factor, obtain two pressure readings at different pump rates and use the following formula:

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

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

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

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 (30 spm ÷ 60 spm)^{1.7768}

New circulating pressure, psi = 1800 psi x 0.2918299

New circulating pressure = 525 psi

18. Cost Per Foot

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

Example: Determine the drilling cost (CT), 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

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

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

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

19. Temperature Conversion Formulas

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

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

Example: Convert 95 °F to °C:

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

$$^{\circ}\text{C} = 35 \quad \quad \quad ^{\circ}\text{C} = 35$$

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

$$^{\circ}\text{F} = (^{\circ}\text{C} \times 9) \div 5 + 32 \quad \text{OR} \quad ^{\circ}\text{F} = 24 \times 1.8 + 32$$

Example: Convert 24 °C to °F:

$$^{\circ}\text{F} = (24 \times 9) \div 5 + 32 \quad \text{OR} \quad ^{\circ}\text{F} = 24 \times 1.8 + 32$$

$$^{\circ}\text{F} = 75.2 \quad \quad \quad ^{\circ}\text{F} = 75.2$$

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

$$^{\circ}\text{K} = ^{\circ}\text{C} + 273.16$$

Example: Convert 35 °C to °K:

$$^{\circ}\text{K} = 35 + 273.16$$

$$^{\circ}\text{K} = 308.16$$

Convert temperature, $^{\circ}\text{Fahrenheit (F)}$ to $^{\circ}\text{Rankine (R)}$

$$^{\circ}\text{R} = ^{\circ}\text{F} + 459.69$$

Example: Convert 260 $^{\circ}\text{F}$ to $^{\circ}\text{R}$:

$$^{\circ}\text{R} = 260 + 459.69$$

$$^{\circ}\text{R} = 719.69$$

Rule of thumb formulas for temperature conversion

a) Convert $^{\circ}\text{F}$ to $^{\circ}\text{C}$:
$$^{\circ}\text{C} = ^{\circ}\text{F} - 30 \div 2$$

Example: Convert 95 $^{\circ}\text{F}$ to $^{\circ}\text{C}$

$$^{\circ}\text{C} = 95 - 30 \div 2$$

$$^{\circ}\text{C} = 32.5$$

b) Convert $^{\circ}\text{C}$ to $^{\circ}\text{F}$:
$$^{\circ}\text{F} = ^{\circ}\text{C} \times 2 + 30$$

Example: Convert 24 $^{\circ}\text{C}$ to $^{\circ}\text{F}$

$$^{\circ}\text{F} = 24 \times 2 + 30$$

$$^{\circ}\text{F} = 78$$

CHAPTER TWO

BASIC CALCULATIONS

1. Volumes and Strokes

Drill string volume, barrels

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

Annular volume, barrels

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

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

$$\text{Strokes} = \text{barrels} \div \text{pump output, bbl/stk}$$

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 collars — 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: $\text{Barrels} = \frac{4.276^2}{1029.4} \times 9400 \text{ ft}$

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

$$\text{Barrels} = 166.94$$

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

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

$$\text{Barrels} = 5.24$$

c) Total drill string volume: $\text{Total drill string vol., bbl} = 166.94 \text{ bbl} + 5.24 \text{ bbl}$
 $\text{Total drill string vol.} = 172.18 \text{ bbl}$

Annular volume

a) Drill collar / open hole: $\text{Barrels} = \frac{12.25^2 - 8.0^2}{1029.4} \times 600 \text{ ft}$

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

$$\text{Barrels} = 50.16$$

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

$$\text{Barrels} = 0.12149 \times 4900 \text{ ft}$$
$$\text{Barrels} = 595.3$$

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

$$\text{Barrels} = 0.130307 \times 4500 \text{ ft}$$
$$\text{Barrels} = 586.38$$

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

Strokes

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

$$\text{Surface to bit strokes} = 172.16 \text{ bbl} \div 0.136 \text{ bbl/stk}$$
$$\text{Surface to bit strokes} = 1266$$

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

$$\text{Strokes} = \text{annular volume, bbl} \div \text{pump output, bbl/stk}$$

$$\text{Bit to surface strokes} = 1231.84 \text{ bbl} \div 0.136 \text{ bbl/stk}$$
$$\text{Bit to surface strokes} = 9058$$

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

$$\text{Strokes} = \text{drill string vol., bbl} + \text{annular vol., bbl} \div \text{pump output, bbl/stk}$$

$$\text{Total strokes} = (172.16 + 1231.84) \div 0.136$$
$$\text{Total strokes} = 1404 \div 0.136$$
$$\text{Total strokes} = 10,324$$

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:

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

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

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

Step 3 Length of slug in drill pipe:

Slug length, ft = pressure, psi ÷ difference in pressure gradient, psi/ft

Step 4 Volume of slug, barrels:

Slug vol., bbl = slug length, ft x 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 = 12.2 ppg x 0.052 x 184 ft
HP = 117 psi

Step 2 Difference in pressure gradient, psi/ft:

psi/ft = (13.2 ppg — 12.2 ppg) x 0.052
psi/ft = 0.052

Step 3 Length of slug in drill pipe, ft:

Slug length, ft = 117 psi ÷ 0.052
Slug length = 2250 ft

Step 4 Volume of slug, bbl:

Slug vol., bbl = 2250 ft x 0.01422 bbl/ft
Slug vol. = 32.0 bbl

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

Step 1 Length of slug in drill pipe, ft:

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

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

HP, psi = mud wt, ppg x 0.052 x 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 = 117psi

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:

$$P_1 V_1 = P_2 V_2$$

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

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

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

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

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

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

$$P_1 V_1 = P_2 V_2$$

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

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

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

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

Step 3 Determine 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:

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

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

Pre-charge pressure = 1000 psi + 445 psi = 1445 psi

Minimum pressure = 1200 psi + 445 psi = 1645 psi

Maximum pressure = 3000 psi + 445 psi = 3445 psi

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

$$P_1 V_1 = P_2 V_2 \qquad = \quad 1445 \text{ psi} \times 10 = 1645 \times V_2$$

$$\frac{14,450}{1645} = V_2$$

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

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

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

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

$$\frac{14450}{3445} = V_2$$

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

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

Step 4 Determine useable fluid volume per bottle:

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

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:

$$P, \text{psi} = \text{vol. removed, bbl} \div \text{total acc. vol., bbl} \times ((P_f \times P_s) \div (P_s - P_f))$$

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 psi Final accumulator pressure (P_f) = 2200 psi

Volume of fluid removed = 20 gal Total accumulator volume = 180 gal

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

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

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

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

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:

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

where SG = specific gravity of cuttings — bulk density

R_w = resulting weight with cuttings plus water, ppg

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

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

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

$$SG = 2.91$$

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:

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

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

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

Solution: a) Buoyancy factor (BF):

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

$$\text{BF} = 0.8168$$

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:

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

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

Round trip ton-miles (RT_{TM})

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

where RT_{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):

$$W_c = (300 \times 83 \times 0.8534) - (300 \times 13.3 \times 0.8534)$$

$$W_c = 21,250 - 3,405$$

$$W_c = 17,845 \text{ lb}$$

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

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

$$RT_{TM} = \frac{11.35 \times 4000 \times 4060 + 8000 \times 47,845}{5280 \times 2000}$$

10,560,000

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

$$RT_{TM} = 53.7$$

Drilling or “connection” ton-miles

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

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

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

where Td = drilling or “connection” ton-miles

T₂ = ton-miles for one round trip — depth where drilling stopped before coming out of hole.

T₁ = ton-miles for one round trip — depth where drilling started.

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

$$Td = 3 \times (64.6 - 53.7)$$

$$Td = 3 \times 10.9$$

$$Td = 32.7 \text{ ton-miles}$$

Ton-miles during coring operations

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

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

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

where Tc = ton-miles while coring

T₄ = ton-miles for one round trip — depth where coring stopped before coming out of hole

T₃ = 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:

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

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, ft³/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:

$$\begin{aligned}\text{Weight, lb/sk} &= 0.04 \times 94 \text{ lb/sk} \\ \text{Weight} &= 3.76 \text{ lb/sk}\end{aligned}$$

2) Total water requirement:

$$\begin{aligned}\text{Water} &= 5.1 \text{ (cement)} + 2.6 \text{ (bentonite)} \\ \text{Water} &= 7.7 \text{ gal/sk of cement}\end{aligned}$$

3) Volume of slurry:

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

$$\begin{aligned}\text{Vol. gallsk} &= 3.5938 + 0.1703 + 7.7 \\ \text{Vol.} &= 11.46 \text{ gal/sk}\end{aligned}$$

4) Slurry yield, ft³/sk:

$$\begin{aligned}\text{Yield, ft}^3/\text{sk} &= 11.46 \text{ gal/sk} \div 7.48 \text{ gal/ft}^3 \\ \text{Yield} &= 1.53 \text{ ft}^3/\text{sk}\end{aligned}$$

5) Slurry density, lb/gal:

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

$$\text{Density, lb/gal} = \frac{61.90}{11.46}$$

$$\text{Density} = 14.13 \text{ lb/gal}$$

Water requirements

a) Weight of materials, lb/sk:

$$\text{Weight, lb/sk} = 94 + (8.33 \times \text{vol of water, gal}) + (\% \text{ of additive} \times 94)$$

b) Volume of slurry, gal/sk:

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

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, galsk
	Slurry yield, ft ³ /sk	Check slurry weight, lb/gal

1) Weight of materials, lb/sk:

$$\text{Weight, lb/sk} = 94 + (0.06 \times 94) + (8.33 \times "y")$$

$$\text{Weight, lb/sk} = 94 + 5.64 + 8.33 "y"$$

$$\text{Weight} = 99.64 + 8.33 "y"$$

2) Volume of slurry, gal/sk:

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

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

$$\text{Vol, gal/sk} = 3.86$$

3) Water requirements using material balance equation

$$99.64 + 8.33 "y" = (3.86 + "y") \times 14.0$$

$$99.64 + 8.33 "y" = 54.04 + 14.0 "y"$$

$$99.64 - 54.04 = 14.0 "y" - 8.33 "y"$$

$$45.6 = 5.67 "y"$$

$$45.6 \div 5.67 = "y"$$

$$8.0 = "y" \text{ Thus , water required} = 8.0 \text{ gal/sk of cement}$$

4) Slurry yield, ft³/sk:

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

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

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

5) Check slurry density, lb/gal:

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

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

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

Field cement additive calculations

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

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

a) Volume of mixing water, gal:

$$\text{Volume} = 240 \text{ sk} \times 8.6 \text{ gal/sk}$$

$$\text{Volume} = 2064 \text{ gal}$$

b) Total weight, lb, of mixing water:

$$\text{Weight} = 2064 \text{ gal} \times 8.33 \text{ lb/gal}$$

$$\text{Weight} = 17,193 \text{ lb}$$

c) Bentonite requirement, Lb:

$$\text{Bentonite} = 17,193 \text{ lb} \times 0.015\%$$

$$\text{Bentonite} = 257.89 \text{ lb}$$

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:

$$\text{Weight} = 240 \text{ sk} \times 94 \text{ lb/sk}$$

$$\text{Weight} = 22,560 \text{ lb}$$

b) Halad = 0.5%

$$\text{Halad} = 22,560 \text{ lb} \times 0.005$$

$$\text{Halad} = 112.8 \text{ lb}$$

c) CFR-2 = 0.40%

$$\text{CFR-2} = 22,560 \text{ lb} \times 0.004$$

$$\text{CFR-2} = 90.24 \text{ lb}$$

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

	Water Requirement gal/94 lb/sk	Specific Gravity
API Class Cement		
Class A & B	5.2	3.14

Formulas and Calculations

Class C	6.3	3.14
Class D & E	4.3	3.14
Class G	5.0	3.14
Class H	4.3 — 5.2	3.14
Chem Comp Cement	6.3	3.14
Attapulgate	1.3/2% in cement	2.89
Cement Fondu	4.5	3.23

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

	Water Requirement gal/94 lb/sk	Specific Gravity
Lumnite Cement	4.5	3.20
Trinity Lite-weight Cement	9.7	2.80
Bentonite	1.3/2% in cement	2.65
Calcium Carbonate Powder	0	1.96
Calcium Chloride	0	1.96
Cal-Seal (Gypsum Cement)	4.5	2.70
CFR-1	0	1.63
CFR-2	0	1.30
D-Air-1	0	1.35
D-Air-2	0	1.005
Diacel A	0	2.62
Diacel D	3.3-7.4/10% in cement	2.10
Diacel LWL	0 (up to 0.7%) 0.8:1/1% in cement	1.36
Gilsonite	2/50-lb/ft ³	1.07
Halad-9	0(up to 5%) 0.4-0.5 over 5%	1.22
Halad 14	0	1.31
HR-4	0	1.56
HR-5	0	1.41
HR-7	0	1.30
HR-12	0	1.22
HR-15	0	1.57
Hydrated Lime	14.4	2.20
Hydromite	2.82	2.15
Iron Carbonate	0	3.70
LA-2 Latex	0.8	1.10
NF-D	0	1.30
Perlite regular	4/8 lb/ft ³	2.20
Perlite 6	6/38 lb/ft ³	—
Pozmix A	4.6 — 5	2.46
Salt (NaCl)	0	2.17

Formulas and Calculations

Sand Ottawa	0	2.63
Silica flour	1.6/35% in cement	2.63
Coarse silica	0	2.63
Spacer sperse	0	1.32
Spacer mix (liquid)	0	0.932
Tuf Additive No. 1	0	1.23
Tuf Additive No. 2	0	0.88
Tuf Plug	0	1.28

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

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

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

Water requirement of cement = 4.3 gal/sk

Water requirement of additive (hematite) = 0.34 gal/sk

Specific gravity of cement = 3.14

Specific gravity of additive (hematite) = 5.02

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

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

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

x = 15.1 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:

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

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

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

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

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:

Casing capacity, bbl = casing capacity, bbl/ft x feet of casing to the float collar

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

Strokes = casing capacity, bbl $\div$ pump output, bbl/stk

Example: From the data listed below determine the following:

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

Data: Casing setting depth = 3000 ft Hole size = 17-1/2 in.
Casing 54.5 lb/ft = 13-3/8 in. Casing ID = 12.615 in.
Float collar (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:

$$\text{Annular capacity, ft}^3/\text{ft} = \frac{17.5^2 - 12.615^2}{183.35}$$

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

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

b) Casing capacity, ft³/ft:

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

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

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

c) Casing capacity, bbl/ft:

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

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

1029.4

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 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:

$$\text{Annular capacity, ft}^3/\text{ft} = \frac{D_h, \text{ in.}^2 - D_p, \text{ in.}^2}{183, 35}$$

b) Casing capacity, ft³/ft:

$$\text{Casing capacity, ft}^3/\text{ft} = \frac{ID, \text{ in.}^2}{183 .35}$$

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:

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

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

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

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

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

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

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

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

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

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

1. Height, ft, of the cement in the annulus
2. Amount, ft³, 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 ft³/sk
Excess volume = 50%

Step 1 Determine the following capacities:

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

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

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

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

b) Casing capacity, ft³/ft:

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

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

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

Step 2 Determine the slurry volume, ft³:

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

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

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

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

$$\begin{aligned}\text{Feet} &= (575 \text{ ft}^3 - 86.79 \text{ ft}^3) \div 0.6946 \text{ ft}^3/\text{ft} \div 1.50 \\ \text{Feet} &= 468.58\end{aligned}$$

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

$$\begin{aligned}\text{Depth} &= 3000 \text{ ft} - 468.58 \text{ ft} \\ \text{Depth} &= 2531.42 \text{ ft}\end{aligned}$$

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

$$\begin{aligned}\text{Barrels} &= 2900 \text{ ft} \times 0.01776 \text{ bbl}/\text{ft} \\ \text{Barrels} &= 51.5\end{aligned}$$

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

$$\begin{aligned}\text{Strokes} &= 51.5 \text{ bbl} \div 0.136 \text{ bbl}/\text{stk} \\ \text{Strokes} &= 379\end{aligned}$$

11. Setting a Balanced Cement Plug

Step 1 Determine the following capacities:

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

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

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

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

c) Hole or casing capacity, ft³/ft:

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

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

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

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

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

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:

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

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:

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

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:

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

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:

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

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:

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

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

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

$$\text{Sacks of cement} = 129$$

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

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

$$\text{Spacer vol} = 1.018 \text{ bbl}$$

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

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

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

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

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

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

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

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

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

A cement plug with 100 sk of cement is to be used in an 8-1/2 in. hole. Use 1.15 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:

$$\text{Feet} = 100 \text{ sk} \times 1.15 \text{ ft}^3/\text{sk} \div 0.3941 \text{ ft}^3/\text{ft} \div 1.50$$

$$\text{Feet} = 194.5$$

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

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

$$P_D = 684 \text{ psi}$$

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

Mud wt, ppg = pressure required $\div 0.052 \div$ casing length, ft to balance forces, psi

New mud weight, ppg

Mud wt, ppg = mud wt increase, ppg $\div$ 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) Upward force, lb = pressure, psi $\times$ area, sq in.

d) Difference in = upward force, lb — downward force, lb 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

area, sq in. = 13.3752 $\times$ 0.7854

area, = 140.5 sq in.

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

Force, lb = 140.5 sq in. $\times$ 60 psi

Force = 8430 lb

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

Weight, lb = 54.5 lb/ft $\times$ 164 ft $\times$ 0.8656

Weight = 7737 lb

Determine the difference in force, lb

Differential force, lb = downward force, lb — upward force, lb

Differential force, lb = 7737 lb — 8430 lb

Differential force = — 693 lb

Therefore: Unless the casing is tied down or stuck, it could 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

$$\text{New mud wt, ppg} = 8.8 \text{ ppg} + 0.6 \text{ ppg}$$
$$\text{New mud wt} = 9.4 \text{ ppg}$$

Check the forces with the new mud weight

a) $\text{psi/ft} = (15.8 - 9.4) \times 0.052$

$$\text{psi/ft} = 0.3328$$

b) $\text{psi} = 0.3328 \text{ psi/ft} \times 164 \text{ ft}$

$$\text{psi} = 54.58$$

c) Upward force, lb = $54.58 \text{ psi} \times 140.5 \text{ sq in.}$

$$\text{Upward force} = 7668 \text{ lb}$$

d) Differential force, lb = downward force — upward force

$$\text{Differential force, lb} = 7737 \text{ lb} - 7668 \text{ lb}$$
$$\text{Differential force} = + 69 \text{ lb}$$

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)
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 bbl/ft + 0.0583 bbl/ft = 0.0657 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 Water added = 150 bbl required to fill annulus
Weight of water = 8.33 ppg Annular capacity = 0.1279 bbl/ft (12-1/4 x 5.0 in.)
TVD = 10,000 ft

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**

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

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

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

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

Determine free point constant (FPC)

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

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

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

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

$$\text{FPC} = (452 - 3.826^2 \times 0.7854) \times 2500$$

$$\text{FPC} = 4,407 \times 2500$$

$$\text{FPC} = 11,017.5$$

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:

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

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

Method 2

$$\text{Free pipe, ft} = \frac{735,294 \times e \times W_{dp}}{}$$

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 lb/ft

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

Free pipe = 10,547 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:

Height ft = amount of overbalance, psi $\div$ 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

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:

$$\text{Height, ft} = 225 \text{ psi} \div 0.2184 \text{ psi/ft}$$

$$\text{Height} = 1030 \text{ ft}$$

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:

$$\text{VopI bbl} = \text{annular capacity, bbl/ft} \times \text{section length, ft} \times \text{washout factor}$$

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

$$\text{Barrels} = \text{Barrels required in annulus plus barrels to be left in drill string}$$

Step 4 Determine drill string capacity, bbl:

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

Step 5 Determine strokes required to pump pill:

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

Step 6 Determine number of barrels required to chase pill:

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

Step 7 Determine strokes required to chase pill:

$$\text{Strokes} = \frac{\text{bbl required to chase pill}}{\text{bbl/stk}} + \text{strokes required to displace surface system}$$

Step 8 Total strokes required to spot the pill:

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

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:

Data:	Well depth	= 10,000 ft	Pump output	= 0.117 bbl/stk
	Hole diameter	= 8-1/2 in.	Washout factor	= 20%
	Drill pipe	= 5.0 in. 19.5 lb/ft	Drill collars	= 6-1/2 in. OD x 2-1/2 in. ID
	capacity	= 0.01776 bbl/ft	capacity	= 0.006 1 bbl/ft
	length	= 9400 ft	length	= 600 ft

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

Step 1 Annular capacity around drill pipe and drill collars:

a) Annular capacity around drill collars:

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

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

b) Annular capacity around drill pipe:

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

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

Step 2 Determine total volume of pill required in annulus:

a) Volume opposite drill collars:

$$\begin{aligned}\text{Vol, bbl} &= 0.02914 \text{ bbl/ft} \times 600 \text{ ft} \times 1.20 \\ \text{Vol} &= 21.0 \text{ bbl}\end{aligned}$$

b) Volume opposite drill pipe:

$$\begin{aligned}\text{Vol, bbl} &= 0.0459 \text{ bbl/ft} \times 200 \text{ ft} \times 1.20 \\ \text{Vol} &= 11.0 \text{ bbl}\end{aligned}$$

c) Total volume bbl, required in annulus:

$$\begin{aligned}\text{Vol, bbl} &= 21.0 \text{ bbl} + 11.0 \text{ bbl} \\ \text{Vol} &= 32.0 \text{ bbl}\end{aligned}$$

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

$$\begin{aligned}\text{Barrels} &= 32.0 \text{ bbl (annulus)} + 24.0 \text{ bbl (drill pipe)} \\ \text{Barrels} &= 56.0 \text{ bbl}\end{aligned}$$

Step 4 Determine drill string capacity:

a) Drill collar capacity, bbl:

$$\begin{aligned}\text{Capacity, bbl} &= 0.0062 \text{ bbl/ft} \times 600 \text{ ft} \\ \text{Capacity} &= 3.72 \text{ bbl}\end{aligned}$$

b) Drill pipe capacity, bbl:

$$\begin{aligned}\text{Capacity, bbl} &= 0.01776 \text{ bbl/ft} \times 9400 \text{ ft} \\ \text{Capacity} &= 166.94 \text{ bbl}\end{aligned}$$

c) Total drill string capacity, bbl:

$$\begin{aligned}\text{Capacity, bbl} &= 3.72 \text{ bbl} + 166.94 \text{ bbl} \\ \text{Capacity} &= 170.6 \text{ bbl}\end{aligned}$$

Step 5 Determine strokes required to pump pill:

$$\begin{aligned}\text{Strokes} &= 56 \text{ bbl} \div 0.117 \text{ bbl/stk} \\ \text{Strokes} &= 479\end{aligned}$$

Step 6 Determine bbl required to chase pill:

$$\begin{aligned}\text{Barrels} &= 170.6 \text{ bbl} - 24 \text{ bbl} \\ \text{Barrels} &= 146.6\end{aligned}$$

Step 7 Determine strokes required to chase pill:

$$\begin{aligned}\text{Strokes} &= 146.6 \text{ bbl} \div 0.117 \text{ bbl/stk} + 80 \text{ stk} \\ \text{Strokes} &= 1333\end{aligned}$$

Step 8 Determine strokes required to spot the pill:

$$\begin{aligned}\text{Total strokes} &= 479 + 1333 \\ \text{Total strokes} &= 1812\end{aligned}$$

18. Pressure Required to Break Circulation

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

$$P_{gs} = (y \div 300 \div d) L$$

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

$$P_{gs} = (10 \div 300 \div 4.276) 12,000 \text{ ft}$$

$$P_{gs} = 0.007795 \times 12,000 \text{ ft}$$

$$P_{gs} = 93.5 \text{ psi}$$

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

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

$$P_{gs} = y \div [300 (D_h, \text{ in.} - D_p, \text{ in.})] \times L$$

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
 $D_h = 12\text{-}1/4$ in. $D_p = 5.0$ in.

$$P_{gs} = 10 \div [300 \times (12.25 - 5.0)] \times 12,000 \text{ ft}$$

$$P_{gs} = 10 \div 2175 \times 12,000 \text{ ft}$$

$$P_{gs} = 55.2 \text{ psi}$$

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

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CHAPTER THREE

DRILLING FLUIDS

1. Increase Mud Density

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

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

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

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

$$\text{Barite, sk/100 bbl} = \frac{2940}{21.0}$$

$$\text{Barite} = 140 \text{ sk/ 100 bbl}$$

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

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

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

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

$$\text{Volume increase, per 100 bbl} = \frac{200}{21}$$

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

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

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

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

$$\text{Starting volume, bbl} = \frac{2100}{23}$$

$$\text{Starting volume} = 91.3 \text{ bbl}$$

Mud weight increase with calcium carbonate (SG — 2.7)

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

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

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

$$\text{Sacks/ 100 bbl} = \frac{945 (13.0 - 12.0)}{22.5 - 13.0}$$

$$\text{Sacks/ 100 bbl} = \frac{945}{9.5}$$

$$\text{Sacks/ 100 bbl} = 99.5$$

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

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

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

$$\text{Volume increase, per 100 bbl} = \frac{100 (13.0 - 12.0)}{22.5 - 13.0}$$

$$\text{Volume increase, per 100 bbl} = \frac{100}{9.5}$$

Volume increase = 10.53 bbl per 100 bbl

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:

$$\text{Starting volume, bbl} = \frac{100(22.5 - 13.0)}{22.5 - 12.0}$$

$$\text{Starting volume, bbl} = \frac{950}{10.5}$$

$$\text{Starting volume} = 90.5 \text{ bbl}$$

Mud weight increase with hematite (SG — 4.8)

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

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

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

$$\text{Hematite, sk/100 bbl} = \frac{3360}{26}$$

$$\text{Hematite} = 129.2 \text{ sk/100 bbl}$$

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

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

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

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

$$\text{Volume increase, per 100 bbl} = \frac{200}{26}$$

$$\text{Volume increase} = 7.7 \text{ bbl per 100 bbl}$$

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

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

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:

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

$$\text{Starting volume, bbl} = \frac{2600}{28}$$

$$\text{Starting volume} = 92.9 \text{ bbl}$$

2. Dilution

Mud weight reduction with water

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

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

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

$$\text{Water, bbl} = \frac{2000}{3.67}$$

$$\text{Water} = 54.5 \text{ bbl}$$

Mud weight reduction with diesel oil

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

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

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

$$\text{Diesel, bbl} = \frac{200}{5.0}$$

$$\text{Diesel} = 40 \text{ bbl}$$

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/ft³, etc.)
 V_2 = volume of fluid 2 (bbl, gal, etc.) D_2 = density of fluid 2 (ppg, lb/ft³, etc.)
 V_F = volume of final fluid mix D_F = density of final fluid mix

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

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

Given: 400 bbl of 11.0 ppg mud on hand, and
 400 bbl of 14.0 ppg mud on hand

Solution: let V_1 = bbl of 11.0 ppg mud
 V_2 = bbl of 14.0 ppg mud

then a) $V_1 + V_2 = 300 \text{ bbl}$
 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:

$$\begin{array}{rcl} \text{b)} & (11.0) (V_1) + (14.0) (V_2) & = 3450 \\ \text{— a)} & (11.0) (V_1) + (11.0) (V_2) & = 3300 \\ & \underline{0} & (3.0) (V_2) = 150 \\ & & 3 \quad V_2 = 150 \end{array}$$

$$V_2 = \frac{150}{3}$$

$$V_2 = 50$$

Therefore: $V_2 = 50 \text{ bbl of } 14.0 \text{ ppg mud}$
 $V_1 + V_2 = 300 \text{ bbl}$
 $V_1 = 300 - 50$
 $V_1 = 250 \text{ bbl of } 11.0 \text{ ppg mud}$

Check: $V_1 = 50 \text{ bbl}$ $D_1 = 14.0 \text{ ppg}$
 $V_2 = 150 \text{ bbl}$ $D_2 = 11.0 \text{ ppg}$
 $V_F = 300 \text{ bbl}$ $D_F = \text{final density, ppg}$

$$\begin{array}{rcl} (50) (14.0) + (250) (11.0) & = & 300 D_F \\ 700 + 2750 & = & 300 D_F \end{array}$$

$$\begin{aligned} 3450 &= 300 D_F \\ 3450 \div 300 &= D_F \\ 11.5 \text{ ppg} &= D_F \end{aligned}$$

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 = bbl of 11.0 ppg mud D_1 = density of 11.0 ppg mud
 V_2 = bbl of 14.0 ppg mud D_2 = density of 14.0 ppg mud
 V_F = final volume, bbl D_F = final density, ppg

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

$$\begin{aligned} (400)(11.0) + (400)(14.0) &= 800 D_F \\ 4400 + 5600 &= 800 D_F \\ 10,000 &= 800 D_F \\ 10,000 \div 800 &= D_F \\ 12.5 \text{ ppg} &= D_F \end{aligned}$$

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, $D_1 = 7.0$ ppg
The weight of water, $D_2 = 8.33$ ppg

$$\begin{aligned} (0.75)(7.0) + (0.25)(8.33) &= (0.75 + 0.25) D_F \\ 5.25 + 2.0825 &= 1.0 D_F \\ 7.33 &= D_F \end{aligned}$$

Therefore: The density of the oil/water mixture = 7.33 ppg

Starting volume of liquid (oil plus water) required to prepare a desired volume of mud

$$SV = \frac{35 - W_2}{35 - W_1} \times DV$$

where SV = starting volume, bbl W_1 = initial density of oil/water mixture, ppg
 W_2 = desired density, ppg Dv = desired volume, bbl

Example: $W_1 = 7.33$ ppg (o/w ratio — 75/25) $W_2 = 16.0$ ppg Dv = 100 bbl

Solution:

$$SV = \frac{35 - 16}{35 - 7.33} \times 100$$

$$SV = \frac{19}{27.67} \times 100$$

$$SV = 0.68666 \times 100$$

$$SV = 68.7 \text{ bbl}$$

Oil/water ratio from retort data

Obtain the percent-by-volume oil and percent-by-volume water from retort analysis or mud still analysis. From the data obtained, the oil/water ratio is calculated as follows:

$$\text{a) \% oil in liquid phase} = \frac{\% \text{ by vol oil}}{\% \text{ by vol oil} + \% \text{ by vol water}} \times 100$$

$$\text{b) \% water in liquid phase} = \frac{\% \text{ by vol water}}{\% \text{ by vol oil} + \% \text{ by vol water}} \times 100$$

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:

$$\text{a) \% oil in liquid phase} = \frac{51}{51 + 17} \times 100$$

$$\% \text{ oil in liquid phase} = 75$$

$$\text{b) \% water in liquid phase} = \frac{17}{51 + 17} \times 100$$

$$\% \text{ water in liquid phase} = 25$$

c) Result: Therefore, the oil/water ratio is reported as 75/25: 75% oil and 25% water.

Changing oil/water ratio

NOTE: If the oil/water ratio is to be increased, add oil; if it is to be decreased, add water.

Retort analysis: % by volume oil = 51
 % by volume water = 17
 % by volume solids = 32

The oil/water ratio is 75/25.

Example 1: Increase the oil/water ratio to 80/20:

In 100 bbl of this mud, there are 68 bbl of liquid (oil plus water). To increase the oil/water ratio, add oil. The total liquid volume will be increased by the volume of the oil added, but the water volume will not change. The 17 bbl of water now in the mud represents 25% of the liquid volume, but it will represent only 20% of the new liquid volume.

Therefore: let x = final liquid volume

then, $0.20x = 17$

$$x = 17 \div 0.20$$

$$x = 85 \text{ bbl}$$

The new liquid volume = 85 bbl

Barrels of oil to be added:

Oil, bbl = new liquid vol — original liquid vol

Oil, bbl = 85 — 68

Oil = 17 bbl oil per 100 bbl of mud

Check the calculations. If the calculated amount of liquid is added, what will be the resulting oil/water ratio?

$$\% \text{ oil in liquid phase} = \frac{\text{original vol oil} + \text{new vol oil}}{\text{original liquid oil} + \text{new oil added}} \times 100$$

$$\% \text{ oil in liquid phase} = \frac{51+17}{68+17} \times 100$$

$$\% \text{ oil in liquid phase} = 80$$

$$\% \text{ water would then be: } 100 - 80 = 20$$

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

$$\text{Water, bbl} = 73 - 68$$

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)

$$SW = (5.88 \times 10^{-8}) \times [(\text{ppm Cl})^{1.2} + 1] \times \% \text{ by vol water}$$

Step 2 Percent by volume suspended solids (SS)

$$SS = 100 - \% \text{ by vol oil} - \% \text{ by vol SW}$$

Step 3 Average specific gravity of saltwater (ASG_{sw})

$$ASG_{sw} = (\text{ppm Cl})^{0.95} \times (1.94 \times 10^{-6}) + 1$$

Step 4 Average specific gravity of solids (ASG)

$$ASG = \frac{(12 \times MW) - (\% \text{ by vol SW} \times ASG_{sw}) - (0.84 \times \% \text{ by vol oil})}{SS}$$

Step 5 Average specific gravity of solids (ASG)

$$ASG = \frac{(12 \times MW) - \% \text{ by vol water} - \% \text{ by vol oil}}{\% \text{ by vol solids}}$$

Step 6 Percent by volume low gravity solids (LGS)

$$\text{LGS} = \frac{\% \text{ by volume solids} \times (4.2 - \text{ASG})}{1.6}$$

Step 7 Percent by volume barite

$$\text{Barite, \% by vol} = \% \text{ by vol solids} - \% \text{ by vol LGS}$$

Step 8 Pounds per barrel barite

$$\text{Barite, lb/bbl} = \% \text{ by vol barite} \times 14.71$$

Step 9 Bentonite determination

If cation exchange capacity (CEC)/methylene blue test (MBT) of shale and mud are KNOWN:

a) Bentonite, lb/bbl:

$$\text{Bentonite, lb/bbl} = 1 \div (1 - (S \div 65) \times (M - 9 \times (S \div 65))) \times \% \text{ by vol LGS}$$

Where S = CEC of shale M = CEC of mud

b) Bentonite, % by volume:

$$\text{Bent, \% by vol} = \text{bentonite, lb/bbl} \div 9.1$$

If the cation exchange capacity (CEC)/methylene blue (MBT) of SHALE is UNKNOWN:

$$\text{a) Bentonite, \% by volume} = \frac{M - \% \text{ by volume LGS}}{8}$$

where M = CEC of mud

$$\text{b) Bentonite, lb/bbl} = \text{bentonite, \% by vol} \times 9.1$$

Step 10 Drilled solids, % by volume

$$\text{Drilled solids, \% by vol} = \text{LGS, \% by vol} - \text{bentonite, \% by vol}$$

Step 11 Drilled solids, lb/bbl

$$\text{Drilled solids, lb/bbl} = \text{drilled solids, \% by vol} \times 9.1$$

<i>Example:</i> 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)

$$SW = [(5.88 \times 10^{-8})(73,000)^{1.2} + 1] \times 57$$

$$SW = [(5.88^{-8} \times 685468.39) + 1] \times 57$$

$$SW = (0.0403055 + 1) \times 57$$

$$SW = 59.2974 \text{ percent by volume}$$

2. Percent by volume suspended solids (SS)

$$SS = 100 - 7.5 - 59.2974$$

$$SS = 33.2026 \text{ percent by volume}$$

3. Average specific gravity of saltwater (ASG_{sw})

$$ASG_{sw} = [(73,000)^{0.95} - (1.94 \times 10^{-6})] + 1$$

$$ASG_{sw} = (41,701.984 \times 1.94^{-6}) + 1$$

$$ASG_{sw} = 0.0809018 + 1$$

$$ASG_{sw} = 1.0809$$

4. Average specific gravity of solids (ASG)

$$ASO = \frac{(12 \times 16) - (59.2974 \times 1.0809) - (0.84 \times 7.5)}{33.2026}$$

$$ASG = \frac{121.60544}{33.2026}$$

$$ASG = 3.6625$$

5. Because a high chloride example is being used, Step 5 is omitted.

6. Percent by volume low gravity solids (LGS)

$$LGS = \frac{33.2026 \times (4.2 - 3.6625)}{1.6}$$

$$LGS = 11.154 \text{ percent by volume}$$

7. Percent by volume barite

$$\text{Barite, \% by volume} = 33.2026 - 11.154$$

$$\text{Barite} = 22.0486 \text{ \% by volume}$$

8. Barite, lb/bbl

$$\text{Barite, lb/bbl} = 22.0486 \times 14.71$$

$$\text{Barite} = 324.3349 \text{ lb/bbl}$$

9. Bentonite determination

$$a) \text{ lb/bbl} = 1 \div (1 - (7 \div 65) \times (30 - 9 \times (7 \div 65))) \times 11.154$$

$$\text{lb/bbl} = 1.1206897 \times 2.2615385 \times 11.154$$

$$\text{Bent} = 28.26965 \text{ lb/bbl}$$

b) Bentonite, % by volume

$$\text{Bent, \% by vol} = 28.2696 \div 9.1$$

$$\text{Bent} = 3.10655\% \text{ by vol}$$

10. Drilled solids, percent by volume

$$\text{Drilled solids, \% by vol} = 11.154 - 3.10655$$

$$\text{Drilled solids} = 8.047\% \text{ by vol}$$

11. Drilled solids, pounds per barrel

$$\text{Drilled solids, lb/bbl} = 8.047 \times 9.1$$

$$\text{Drilled solids} = 73.2277 \text{ lb/bbl}$$

6. Solids Fractions

Maximum recommended solids fractions (SF)

$$\text{SF} = (2.917 \times \text{MW}) - 14.17$$

Maximum recommended low gravity solids (LGS)

$$\text{LGS} = ((\text{SF} \div 100) - [0.3125 \times ((\text{MW} \div 8.33) - 1)]) \times 200$$

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:

$$\text{SF} = (2.917 \times 14.0) - 14.17$$

$$\text{SF} = 40.838 - 14.17$$

$$\text{SF} = 26.67\% \text{ by volume}$$

Low gravity solids (LOS), % by volume:

$$\text{LGS} = ((26.67 \div 100) - [0.3125 \times ((14.0 \div 8.33) - 1)]) \times 200$$

$$\text{LGS} = 0.2667 - (0.3125 \times 0.6807) \times 200$$

$$\text{LGS} = (0.2667 - 0.2127) \times 200$$

$$\text{LGS} = 0.054 \times 200$$

$$\text{LGS} = 10.8 \% \text{ by volume}$$

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:

$$V_{wm} = \frac{1000 (6 - 4)}{4}$$

$$V_{wm} = \frac{2000}{4}$$

$$V_{wm} = 500 \text{ bbl}$$

If dilution is done with a 2% bentonite slurry, the total would be:

$$V_{wm} = \frac{1000 (6 - 4)}{4 - 2}$$

$$V_{wm} = \frac{2000}{2}$$

$$V_{wm} = 1000 \text{ bbl}$$

8. Displacement — Barrels of Water/Slurry Required

$$V_{wm} = \frac{V_m (F_{ct} - F_{cop})}{F_{ct} - F_{ca}}$$

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%:

$$V_{wm} = \frac{1000(6 - 4)}{6}$$

$$V_{wm} = \frac{2000}{6}$$

$$V_{wm} = 333 \text{ bbl}$$

If displacement is done by adding 2% bentonite slurry, the total volume would be:

$$V_{wm} = \frac{1000(6 - 4)}{6 - 2}$$

$$V_{wm} = \frac{2000}{4}$$

$$V_{wm} = 500 \text{ bbl}$$

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):

$$\text{Volume fraction of solids (SF): } SF = \frac{MW - 8.22}{13.37}$$

$$\text{Mass rate of solids (MS): } MS = 19,530 \times SF \times \frac{V}{T}$$

$$\text{Volume rate of water (WR): } WR = 900 (1 - SF) \frac{V}{T}$$

where SF = fraction percentage of solids

MW = average density of discarded mud, ppg

MS = mass rate of solids removed by one cone of a hydrocyclone, lb/hr

V = volume of slurry sample collected, quarts

T = time to collect slurry sample, seconds

WR = volume of water ejected by one cone of a hydrocyclone, gal/hr

Example: Average weight of slurry sample collected = 16.0 ppg
Sample collected in 45 seconds
Volume of slurry sample collected 2 quarts

a) Volume fraction of solids: $SF = \frac{16.0 - 8.33}{13.37}$

$$SF = 0.5737$$

b) Mass rate of solids: $MS = 19,530 \times 0.5737 \times \frac{2.}{45}$

$$MS = 11,204.36 \times 0.0444$$
$$MS = 497.97 \text{ lb/hr}$$

c) Volume rate of water: $WR = 900 (1 - 0.5737) - \frac{2.}{45}$

$$WR = 900 \times 0.4263 \times 0.0444$$
$$WR = 17.0 \text{ gal/hr}$$

10. Evaluation of Centrifuge

a) Underflow mud volume:

$$QU = \frac{[QM \times (MW - PO)] - [QW \times (PO - PW)]}{PU - PO}$$

b) Fraction of old mud in Underflow:

$$FU = \frac{35 - PU}{35 - MW + (QW \div QM) \times (35 - PW)}$$

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
QM = mud volume into centrifuge, gal/m

PU = Underflow mud density, ppg
PW = dilution water density, ppg

Formulas and Calculations

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:

$$FU = \frac{35 - 23.4}{35 - 16.2 + [(10.5 \div 16.5) \times (35 - 8.34)]}$$

$$FU = \frac{11.6}{18.8 + (0.63636 \times 26.66)}$$

$$FU = 0.324\%$$

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:

$$QB = 16.5 - 7.4 - 8.20 - (7.55 \div 21.7) - (2.01 \div 21.7) \times 35$$

$$QB = 16.5 - 7.4 - 8.20 - 0.348 - 0.0926 \times 35$$

$$QB = 0.4594 \times 35$$

$$QB = 16.079 \text{ lb/mm}$$

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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

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)

Formulas and Calculations

$$= \text{SIDPP} \text{ _____ psi} \div 0.052 \div \text{TVD} \text{ _____ ft} + \text{OMW} \text{ _____ ppg} = \text{_____ ppg}$$

Initial Circulating Pressure (ICP)

$$= \text{SIDPP} \text{ _____ psi} + \text{KRP} \text{ _____ psi} = \text{_____ psi}$$

Final Circulating Pressure (FCP)

$$= \text{KWM} \text{ _____ ppg} \times \text{KRP} \text{ _____ psi} \div \text{OMW} \text{ _____ ppg} = \text{_____ psi}$$

Psi/stroke

$$\text{ICP psi} - \text{FCP} \text{ _____ psi} \div \text{strokes to bit} \text{ _____} = \text{_____ psi/stk}$$

Pressure Chart

Strokes	Pressure	
0		< Initial Circulating Pressure
Strokes to Bit >		<Final Circulating Pressure

Example: Use the following data and fill out a kill sheet:

Data:	Original mud weight	= 9.6 ppg
	Measured depth	= 10,525 ft
	Kill rate pressure @ 50 spm	= 1000 psi
	Kill rate pressure @ 30 spm	= 600 psi
	Drill string:	

Formulas and Calculations

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/stk
Leak-off test with 9.0 ppg mud	= 1130 psi
Casing setting depth	= 4000 ft
Shut-in drill pipe pressure	= 480 psi
Shut-in casing pressure	= 600 psi
Pit volume gain	= 35 bbl
True vertical depth	= 10,000 ft

Calculations

Drill string volume:

Drill pipe capacity 0.01776 bbl/ft 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

Strokes to bit = 1335 stk

Bit to casing strokes: Open hole volume = 779.15 bbl ÷ 0.136 bbl/stk

Bit to casing strokes = 5729 stk

Bit to surface strokes: Annular volume = 1300.35 bbl 0.136 bbl/stk

Bit to surface strokes = 9561 stk

Kill weight mud (KWM) $480 \text{ psi} \div 0.052 \div 10,000 \text{ ft} + 9.6 \text{ ppg}$ = 10.5 ppg

Initial circulating pressure (ICP) $480 \text{ psi} + 1000 \text{ psi}$ = 1480 psi

Final circulating pressure (FCP) $10.5 \text{ ppg} \times 1000 \text{ psi} \div 9.6 \text{ ppg}$ = 1094 psi

Pressure Chart

Strokes to bit = $1335 \div 10 = 133.5$

Therefore, strokes will increase by 133.5 per line:

Pressure Chart

	Strokes	Pressure
133.5 rounded up	0	
133.5 + 133.5 =	134	
+ 133.5 =	267	
+ 133.5 =	401	
+ 133.5 =	534	
+ 133.5 =	668	
+ 133.5 =	801	
+ 133.5 =	935	
+ 133.5 =	1068	
+ 133.5 =	1202	
+ 133.5 =	1335	

Pressure

ICP (1480) psi — FCP (1094) $\div 10 = 38.6 \text{ psi}$

Therefore, the pressure will decrease by 38.6 psi per line.

Pressure Chart

	Strokes	Pressure	
1480 — 38.6 =	0	1480	< ICP
— 38.6 =		1441	
— 38.6 =		1403	
— 38.6 =		1364	
— 38.6 =		1326	
— 38.6 =		1287	
— 38.6 =		1248	
— 38.6 =		1210	
— 38.6 =		1171	
— 38.6 =		1133	
— 38.6 =		1094	< FCP

Trip Margin (TM)

TM = Yield point ÷ 11.7(Dh, in. — Dp, in.)

Example: Yield point = 10 lb/100 sq ft; Dh = 8.5 in.; Dp = 4.5 in.

TM = 10 ÷ 11.7 (8.5 — 4.5)

TM = 0.2 ppg

Determine Psi/stk

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

psi/stk = $\frac{1480 - 1094}{1335}$

psi/stk = 0.289 1

The pressure side of the chart will be as follows:

Pressure Chart

Strokes	Pressure
0	1480

Formulas and Calculations

	1450
	1400
	1350
	1300
	1250
	1200
	1150
	1100
	1094

Adjust the strokes as necessary.

For line 2: How many strokes will be required to decrease the pressure from 1480 psi to 1450 psi?

$$1480 \text{ psi} - 1450 \text{ psi} = 30 \text{ psi}$$

$$30 \text{ psi} \div 0.2891 \text{ psi/stk} = 104 \text{ strokes}$$

For lines 3 to 7: How many strokes will be required to decrease the pressure by 50 psi increments?

Therefore, the new pressure chart will be as follows:

Pressure Chart

	Strokes	Pressure
	0	1480
104	104	1450
104 + 173 =	277	1400
+ 173 =	450	1350
+ 173 =	623	1300
+ 173 =	796	1250
+ 173 =	969	1200
+ 173 =	1142	1150
+ 173 =	1315	1100
	1335	1094

Kill Sheet With a Tapered String

$$\text{psi @ } \underline{\hspace{2cm}} \text{ strokes} = \text{ICP} - [(\text{DPL} \div \text{DSL}) \times (\text{ICP} - \text{FCP})]$$

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:

$$7000 \text{ ft} \times 0.01776 \text{ bbl/ft} \div 0.117 \text{ bbl/stk} = 1063$$

$$6000 \text{ ft} \times 0.00742 \text{ bbl/ft} \div 0.117 \text{ bbl/stk} = 381$$

$$2000 \text{ ft} \times 0.0022 \text{ bbl/ft} \div 0.117 \text{ bbl/stk} = 38$$

$$\text{Total strokes} = 1482$$

Data from kill sheet

Initial drill pipe circulating pressure (ICP) = 1780 psi

Final drill pipe circulating pressure (FCP) = 1067 psi

Step 2 Determine interim pressure for the 5.0 in. drill pipe at 1063 strokes:

$$\begin{aligned} \text{psi @ 1063 strokes} &= 1780 - [(7000 \div 15,000) \times (1780 - 1067)] \\ &= 1780 - (0.4666 \times 713) \\ &= 1780 - 333 \\ &= 1447 \text{ psi} \end{aligned}$$

Step 3 Determine interim pressure for 5.0 in. plus 3-1/2 in. drill pipe
(1063 + 381) = 1444 strokes:

$$\begin{aligned} \text{psi @ 1444 strokes} &= 1780 - [(11,300 \div 15,000) \times (1780 - 1067)] \\ &= 1780 - (0.86666 \times 713) \\ &= 1780 - 618 \\ &= 1162 \text{ psi} \end{aligned}$$

Step 4 Plot data on graph paper

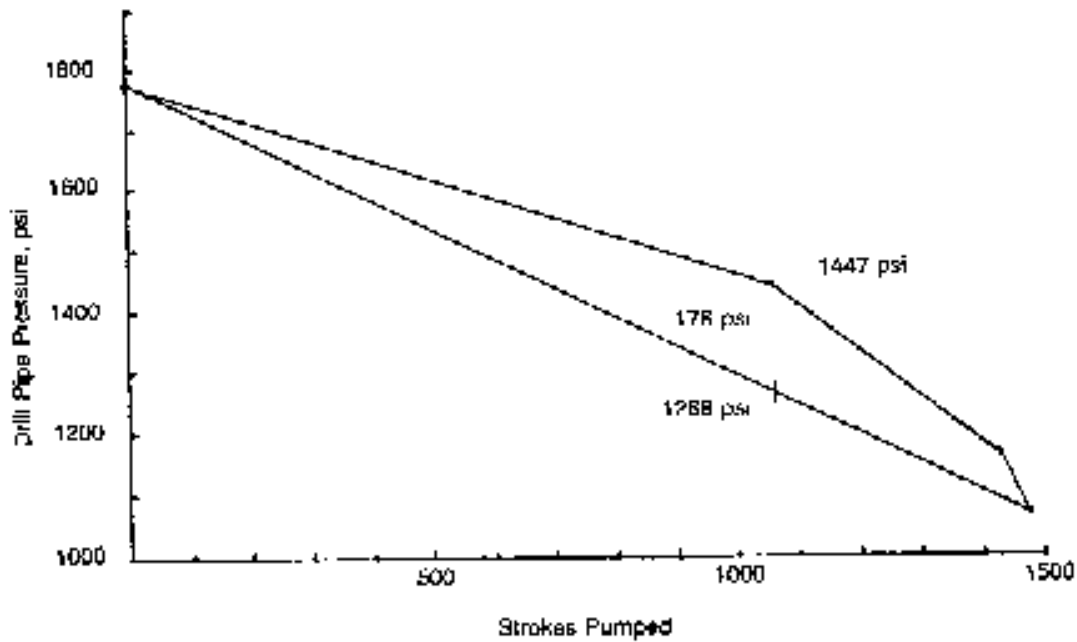


Figure 4-1. Data from kill sheet.

Note. After pumping 1062 strokes, if a straight line would have been plotted, the well would have been underbalanced by 178 psi.

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:

Strokes = drill pipe capacity, bbl/ft x measured depth to KOP, ft x pump output, bbl/stk

Determine strokes from KOP to TD:

Strokes = drill string capacity, bbl/ft x measured depth to TD, ft x pump output, bbl/stk

Kill weight mud: $KWM = SIDPP \div 0.052 \div TVD + OMW$

Initial circulating pressure: $ICP = SIDPP + KRP$

Final circulating pressure: $FCP = KWM \times KRP \div OMW$

Hydrostatic pressure increase from surface to KOP:

psi = $(KWM - OMW) \times 0.052 \times TVD @ KOP$

Friction pressure increase to KOP:

$$FP = (FCP - KRP) \times MD @ KOP \div MD @ TD$$

Circulating pressure when KWM gets to KOP:

$$CP \sim KOP = ICP - HP \text{ increase to KOP} + \text{friction pressure increase, psi}$$

Note: At this point, compare this circulating pressure to the value obtained when using a regular kill sheet.

<i>Example:</i>	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:

$$\begin{aligned} \text{Strokes} &= 0.01776 \text{ bbl/ft} \times 5000 \text{ ft} \div 0.136 \text{ bbl/stk} \\ \text{Strokes} &= 653 \end{aligned}$$

Strokes from KOP to TD:

$$\begin{aligned} \text{Strokes} &= 0.01776 \text{ bbl/ft} \times 10,000 \text{ ft} \div 0.136 \text{ bbl/stk} \\ \text{Strokes} &= 1306 \end{aligned}$$

Total strokes from surface to bit:

$$\text{Surface to bit strokes} = 653 + 1306$$

$$\text{Surface to bit strokes} = 1959$$

Kill weight mud (KWM):

$$KWM = 800 \text{ psi} \times 0.052 + 10,000 \text{ ft} \times 9.6 \text{ ppg}$$

$$KWM = 11.1 \text{ ppg}$$

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:

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:

$$FP_{\max} = (12.0 + 4.0) \times 0.052 \times 12,000 \text{ ft}$$

$$FP_{\max} = 9984 \text{ psi}$$

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

$$\text{Fracture, psi} = \frac{(\text{estimated fracture} + \text{safety factor, ppg}) \times 0.052 \times (\text{casing shoe TVD, ft})}{(\text{gradient, ppg})}$$

Note: A safety factor is added to ensure the formation fractures before BOP pressure rating is exceeded.

Step 2 Determine the hydrostatic pressure of gas in the wellbore (HP_{gas}):

$$HP_{\text{gas}} = \text{gas gradient, psi/ft} \times \text{casing shoe TVD, ft}$$

Step 3 Determine the maximum anticipated surface pressure (MASP), psi:

<i>Example:</i> 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 = $(14.2 + 1.0) \times 0.052 \times 4000 \text{ ft}$
Fracture pressure, psi = 3162 psi

Step 2 $HP_{\text{gas}} = 0.12 \times 4000 \text{ ft}$
 $HP_{\text{gas}} = 480 \text{ psi}$

Step 3 $MASP = 3162 - 480$
 $MASP = 2682 \text{ psi}$

Sizing Diverter Lines

Determine diverter line inside diameter, in., equal to the area between the inside diameter of the casing and the outside diameter of drill pipe in use:

Diverter line ID, in. = $\sqrt{I_b - b_p^2}$

Example: Casing— 13-3/8 in. — J-55 — 61 lb/ft ID = 12.515 in.
Drill pipe — 19.5 lb/ft OD = 5.0 in.

Determine the diverter line inside diameter that will equal the area between the casing and drill pipe:

Diverter line ID, in. = $\text{sq. root } (12.515^2 - 5.0^2)$
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 = $\frac{(\text{equiv. Test mud wt, ppg} - \text{mud wt in use, ppg}) \times 0.052 \times (\text{casing seat, TVD ft})}{1}$

Example: Mud weight = 9.2 ppg
Casing shoe TVD = 4000 ft
Equivalent test mud weight = 13.2 ppg

Solution: Surface pressure = $(13.2 - 9.2) \times 0.052 \times 4000$ 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 = $\frac{(\text{estimated fracture gradient} - \text{mud wt in use, ppg}) \times 0.052 \times (\text{casing shoe TVD, ft})}{1}$

Example: Mud weight = 9.6 ppg Casing shoe TVD = 4000 ft

Estimated fracture gradient = 14.4 ppg

Solution: Estimated leak-off pressure = $(14.4 - 9.6) \times 0.052 \times 4000$ ft
 Estimated leak-off pressure = $4.8 \times 0.052 \times 4000$
 Estimated leak-off pressure = 998 psi

Maximum Allowable Mud Weight From Leak-off Test Data

Max allowable mud weight, ppg = $(\text{leak off pressure, psi}) \div 0.052 \div (\text{casing shoe TVD, ft}) + (\text{mud wt in use, ppg})$

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 = $1040 \div 0.052 \div 4000 + 10.0$
Max allowable mud weight, ppg = 15.0 ppg

Maximum Allowable Shut-in Casing Pressure (MASLCP) also called maximum allowable shut-in annular pressure (MASP):

MASICP = $(\text{maximum allowable mud weight, ppg} - \text{mud wt in use, ppg}) \times 0.052 \times (\text{casing shoe TVD, ft})$
(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 = $(15.0 - 12.2) \times 0.052 \times 4000$ ft
MASICP = 582 psi

Kick Tolerance Factor (KTF)

KTF = $\frac{\text{Casing shoe TVD, ft}}{\text{well depth}} \times (\text{maximum allowable mud wt, ppg} - \text{mud wt in use, ppg})$

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

$$\text{KTF} = (4000 \text{ ft} \div 10,000 \text{ ft}) \times (14.2 \text{ ppg} - 10.0 \text{ ppg})$$
$$\text{KTF} = 1.68 \text{ ppg}$$

Maximum Surface Pressure From Kick Tolerance Data

Maximum surface pressure = kick tolerance factor, ppg $\times$ 0.052 $\times$ TYD, ft

Example: Determine the maximum surface pressure, psi, using the following data:

$$\text{Maximum surface pressure} = 1.68 \text{ ppg} \times 0.052 \times 10,000 \text{ ft}$$
$$\text{Maximum surface pressure} = 874 \text{ psi}$$

Maximum Formation Pressure (FP) That Can be Controlled When Shutting-in a Well

Maximum FP, psi = (kick tolerance factor, ppg + mud wt in use, ppg) $\times$ 0.052 $\times$ 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

$$\text{Maximum FP, psi} = (1.68 \text{ ppg} + 10.0 \text{ ppg}) \times 0.052 \times 10,000 \text{ ft}$$
$$\text{Maximum FP} = 6074 \text{ psi}$$

Maximum Influx Height Possible to Equal Maximum Allowable Shut-in Casing Pressure (MASICP)

Influx height = MASICP, psi $\div$ (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 $\times$ 0.052) = 0.52 psi/ft
Gradient of influx = 0.12 psi/ft

$$\text{Influx height} = 874 \text{ psi} \div (0.52 \text{ psi/ft} - 0.12 \text{ psi/ft})$$
$$\text{Influx height} = 2185 \text{ ft}$$

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: ft = 2185 ft — 500 ft
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

$$\text{MASICP} = P_L - [D \times (\text{mud wt}_2 - \text{mud wt}_1)] 0.052$$

where MASICP = maximum allowable shut-in casing (annulus) pressure, psi

P_L = leak-off pressure, psi

D = true vertical depth to casing shoe, ft

Mud wt_2 = new mud wt, ppg

Mud wt_1 = original mud wt, ppg

Example: Leak-off pressure at casing setting depth (TVD) of 4000 ft was 1040 psi with 10.0 ppg in use. Determine the maximum allowable shut-in casing pressure with a mud weight of 12.5 ppg:

MASICP = 1040 psi — [4000 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

$$\text{FP, psi} = \text{SIDPP, psi} + (\text{mud wt, ppg} \times 0.052 \times \text{TVD, ft})$$

Example: Determine the formation pressure using the following data:

$$\begin{array}{ll} \text{Shut-in drill pipe pressure} = 500 \text{ psi} & \text{Mud weight in drill pipe} = 9.6 \text{ ppg} \\ \text{True vertical depth} = 10,000 \text{ ft} & \end{array}$$

$$\text{FP, psi} = 500 \text{ psi} + (9.6 \text{ ppg} \times 0.052 \times 10,000 \text{ ft})$$

$$\text{FP, psi} = 500 \text{ psi} + 4992 \text{ psi}$$

$$\text{FP} = 5492 \text{ psi}$$

Bottom hole Pressure (BHP) With the Well Shut-in on a Kick

$$\text{BHP, psi} = \text{SIDPP, psi} + (\text{mud wt, ppg} \times 0.052 \times \text{TVD, ft})$$

Example: Determine the bottom hole pressure (BHP) with the well shut-in on a kick:

$$\begin{array}{ll} \text{Shut-in drill pipe pressure} = 500 \text{ psi} & \text{Mud weight in drill pipe} = 9.6 \text{ ppg} \\ \text{True vertical depth} = 10,000 \text{ ft} & \end{array}$$

$$\text{BHP, psi} = 500 \text{ psi} + (9.6 \text{ ppg} \times 0.052 \times 10,000 \text{ ft})$$

$$\text{BHP, psi} = 500 \text{ psi} + 4992 \text{ psi}$$

$$\text{BHP} = 5492 \text{ psi}$$

Shut-in Drill Pipe Pressure (SIDPP)

$$\text{SIDPP, psi} = \text{formation pressure, psi} - (\text{mud wt, ppg} \times 0.052 \times \text{TVD, ft})$$

Example: Determine the shut-in drill pipe pressure using the following data:

$$\begin{array}{ll} \text{Formation pressure} = 12,480 \text{ psi} & \text{Mud weight in drill pipe} = 15.0 \text{ ppg} \\ \text{True vertical depth} = 15,000 \text{ ft} & \end{array}$$

$$\text{SIDPP, psi} = 12,480 \text{ psi} - (15.0 \text{ ppg} \times 0.052 \times 15,000 \text{ ft})$$

$$\text{SIDPP, psi} = 12,480 \text{ psi} - 11,700 \text{ psi}$$

$$\text{SIDPP} = 780 \text{ psi}$$

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

SICP, psi = 12,480 — [(15.0 x 0.052 x 14,600) + (0.12 x 400)]

SICP, psi = 12,480 — 11,388 + 48

SICP = 1044 psi

Height, Ft, of Influx

Height of influx, ft = pit gain, bbl ÷ annular capacity, bbl/ft

Example 1: Determine the height, ft, of the influx using the following data:

Pit gain = 20 bbl Annular capacity — DC/OH = 0.02914 bbl/ft
(Dh = 8.5 in. — Dp = 6.5)

Height of influx, ft = 20 bbl ÷ 0.02914 bbl/ft

Height of influx = 686 ft

Example 2: Determine the height, ft, of the influx using the following data:

Pit gain = 20 bbl Hole size = 8.5 in.
Drill collar OD = 6.5 in. Drill collar length = 450 ft
Drill pipe OD = 5.0 in.

Determine annular capacity, bbl/ft, for DC/OH:

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

Annular capacity = 0.02914 bbl/ft

Determine the number of barrels opposite the drill collars:

Barrels = length of collars x annular capacity

Barrels = 450 ft x 0.02914 bbl/ft

Barrels = 13.1

Determine annular capacity, bbl/ft, opposite drill pipe:

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

Annular capacity = 0.0459 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:

Shut-in casing pressure = 1044 psi Height of influx = 400 ft

Shut-in drill pipe pressure = 780 psi Mud weight = 15.0 ppg

Influx weight, ppg = 15.0 ppg — ((1044 — 780) ÷ 400 x 0.052)

Influx weight, ppg = 15.0 ppg — $\frac{264}{20.8}$

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 = 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:

$$\text{Rate of gas migration, ft/hr} = \frac{\text{increase in casing pressure, psi/hr}}{\text{pressure gradient of mud weight in use, psi/ft}}$$

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

$$\text{Rate of gas migration, ft/hr} = 200 \text{ psi/hr} \div 0.624 \text{ psi/ft}$$

$$\text{Rate of gas migration} = 320.5 \text{ ft/hr}$$

Hydrostatic Pressure Decrease at TD Caused by Gas Cut Mud

Method 1:

$$\text{HP decrease, psi} = \frac{100 (\text{weight of uncut mud, ppg} - \text{weight of gas cut mud, ppg})}{\text{weight of gas cut mud, ppg}}$$

Example: Determine the hydrostatic pressure decrease mud using the following data:

$$\text{Weight of uncut mud} = 18.0 \text{ ppg} \quad \text{Weight of gas cut mud} = 9.0 \text{ ppg}$$

$$\text{HP decrease, psi} = \frac{100 \times (18.0 \text{ ppg} - 9.0 \text{ ppg})}{9.0 \text{ ppg}}$$

$$\text{HP Decrease} = 100 \text{ psi}$$

Method 2: $P = (MG \div C) V$

where P	= reduction in bottomhole pressure, psi	MG	= mud gradient, psi/ft
C	= annular volume, bbl/ft	V	= pit gain, bbl

Example:

$$\begin{aligned} \text{MG} &= 0.624 \text{ psi/ft} \\ \text{C} &= 0.0459 \text{ bbl/ft (Dh = 8.5 in.; Dp = 5.0 in.)} \\ \text{V} &= 20 \text{ bbl} \end{aligned}$$

Solution:

$$\begin{aligned} P &= (0.624 \text{ psi/ft} \div 0.0459 \text{ bbl/ft}) \times 20 \\ P &= 13.59 \times 20 \\ P &= 271.9 \text{ psi} \end{aligned}$$

Maximum Surface Pressure From a Gas Kick in a Water Base Mud

$$\text{MSP}_{\text{gk}} = 0.2 \sqrt{P \times V \times \text{KWM} \div C}$$

where MSP_{gk} = maximum surface pressure resulting from a gas kick in a water base mud

$$P = \text{formation pressure, psi}$$

$$V = \text{pit gain, bbl}$$

KWM = kill weight mud, ppg
 C = annular capacity, bbl/ft

Example: P = 12,480 psi V = 20 bbl
 KWM = 16.0 ppg C = 0.0505 bbl/ft (Dh = 8.5 in. x Dp = 4.5 in.)

Solution: $MSP_{gk} = 0.2 \sqrt{\frac{12,480 \times 20 \times 16.0}{0.0505}}$

$MSP_{gk} = 0.2 \sqrt{79081188}$

$MSP_{gk} = 0.2 \times 8892.76$

$MSP_{gk} = 1779 \text{ psi}$

Maximum Pit Gain From Gas Kick in a Water Base Mud

$$MPG_{gk} = 4 \sqrt{\frac{P \times V \times C}{KWM}}$$

where MPG_{gk} = maximum pit gain resulting from a gas kick in a water base mud

P = formation pressure, psi

V = original pit gain, bbl

C = annular capacity, bbl/ft

KWM = kill weight mud, ppg

Example: P = 12,480 psi V = 20 bbl C = 0.0505 bbl/ft (8.5 in. x 4.5 in.)

Solution: $MPG_{gk} = 4 \sqrt{\frac{12,480 \times 20 \times 0.0505}{16.0}}$

$MPG_{gk} = 4 \sqrt{787.8}$

$MPG_{gk} = 4 \times 28.06$

$MPG_{gk} = 112.3 \text{ bbl}$

Maximum Pressures When Circulating Out a Kick (Moore Equations)

The following equations will be used:

1. Determine formation pressure, psi: **Pb = SIDP + (mud wt, ppg x 0.052 x TVD, ft)**
2. Determine the height of the influx, ft: **hi = pit gain, bbl ÷ annular capacity, bbl/ft**
3. Determine pressure exerted by the influx, psi: **Pi = Pb — [Pm (D — X) + SICP]**
4. Determine gradient of influx, psi/ft: **Ci = Pi ÷ hi**
5. Determine Temperature, °R, at depth of interest: **Tdi = 70°F + (0.012°F/ft. x Di) + 460**
6. Determine A for unweighted mud: **A = Pb — [Pm (D — X) — Pi]**
7. Determine pressure at depth of interest: **Pdi = A + (A² + pm Pb Zdi T°Rdi hi)^{1/2}**

$$2 \quad 4 \quad Zb \quad Tb$$

8. Determine kill weight mud, ppg: **KWM, ppg = SIDPP ÷ 0.052 ÷ TVD, ft + 0MW, ppg**

9. Determine gradient of kill weight mud, psi/ft: **pKWM = KWM, ppg x 0.052**

10. Determine FEET that drill string volume will occupy in the annulus:

$$Di = \text{drill string vol, bbl} \div \text{annular capacity, bbl/ft}$$

11. Determine A for weighted mud: **A = Pb — [pm (D — X) — Pi] + [Di (pKWM — pm)]**

Example: Assumed conditions:

Well depth	= 10,000 ft	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:

$$C_i = 72 \text{ psi} \div 625 \text{ ft}$$

$$C_i = 0.1152 \text{ psi/ft}$$

5. Determine height and pressure of influx around drill pipe:

$$h = 20 \text{ bbl} \div 0.05 \text{ bbl/ft}$$

$$h = 400 \text{ ft}$$

$$P_i = 0.1152 \text{ psi/ft} \times 400 \text{ ft}$$

$$P_i = 46 \text{ psi}$$

6. Determine $T^\circ\text{R}$ at TD and at shoe:

$$\begin{aligned} T^\circ\text{R} @ 10,000 \text{ ft} &= 70 + (0.012 \times 10,000) + 460 \\ &= 70 + 120 + 460 \end{aligned}$$

$$T^\circ\text{R} @ 10,000\text{ft} = 650$$

$$\begin{aligned} T^\circ\text{R} @ 2500 \text{ ft} &= 70 + (0.012 \times 2500) + 460 \\ &= 70 + 30 + 460 \end{aligned}$$

$$T^\circ\text{R} @ 2500\text{ft} = 560$$

7. Determine A:

$$A = 5252 \text{ psi} - [0.4992 (10,000 - 2500) + 46]$$

$$A = 5252 \text{ psi} - (3744 - 46)$$

$$A = 1462 \text{ psi}$$

8. Determine maximum pressure at shoe with drillers method:

$$P_{2500} = \frac{1462}{2} + \left[\frac{1462^2}{4} \frac{(0.4992)(5252)(1)(560)(400)}{(1)(650)} \right]^{1/2}$$

$$= 731 + (534361 + 903512)12$$

$$= 731 + 1199$$

$$P_{2500} = 1930 \text{ psi}$$

Determine maximum pressure at surface with drillers method:

1. Determine A:

$$A = 5252 - [0.4992 (10,000) + 46]$$

$$A = 5252 - (4992 + 46)$$

$$A = 214 \text{ psi}$$

2. Determine maximum pressure at surface with drillers method:

$$P_s = \frac{214}{2} + \left[\frac{214^2}{4} \frac{(0.4992)(5252)(1)(530)(400)}{650} \right]^{1/2}$$

$$= 107 + (11449 + 855109)^{1/2}$$

$$= 107 + 931$$

$$P_s = 1038 \text{ psi}$$

Determine maximum pressure at shoe with wait and weight method:

1. Determine kill weight mud:

$$\text{KWM, ppg} = 260 \text{ psi} \div 0.052 \div 10,000 \text{ ft} + 9.6 \text{ ppg}$$

$$\text{KWM, ppg} = 10.1 \text{ ppg}$$

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:

$$D_i = 135.625 \text{ bbl} \div 0.05 \text{ bbl/ft}$$

$$D_i = 2712.5$$

5. Determine A:

$$A = 5252 - [0.5252 (10,000 - 2500) - 46] + (2712.5 (0.5252 - 0.4992))$$

$$A = 5252 - (3939 - 46) + 70.6$$

$$A = 1337.5$$

6. Determine maximum pressure at shoe with wait and weight method:

$$P_{2500} = \frac{1337.5}{2} + \left[\frac{1337.5^2}{4} + \frac{(0.5252)(5252)(1)(560)(400)}{(1)(650)} \right]^{1/2}$$

$$= 668.75 + (447226 + 950569.98)^{1/2}$$

$$= 668.75 + 1182.28$$

$$= 1851 \text{ psi}$$

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:

$$P_s = \frac{12.25}{2} + \left[\frac{24.5^2}{4} + \frac{(0.5252)(5252)(1)(560)(400)}{(fl(650))} \right]^{1/2}$$

$$P_s = 12.25 + (150.0625 + 95069.98)^{1/2}$$

$$P_s = 12.25 + 975.049$$

$$P_s = 987 \text{ psi}$$

Nomenclature:

A	= pressure at top of gas bubble, psi
Ci	= gradient of influx, psi/ft
D	= total depth, ft
Di	= feet in annulus occupied by drill string volume
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:

$$Q = 0.007 \times md \times D_p \times L \div U \times \ln(Re \div R_w) \times 1,440$$

where Q = flow rate, bbl/min md = permeability, millidarcys
 Dp = pressure differential, psi L = length of section open to wellbore, ft
 U = viscosity of intruding gas, centipoise Re = radius of drainage, ft
 Rw = radius of wellbore, ft

Example: md = 200 md Dp = 624 psi L = 20ft U = 0.3cp ln(Re ÷ Rw) = 2.0

$$Q = 0.007 \times 200 \times 624 \times 20 \div 0.3 \times 2.0 \times 1440$$

$$Q = 20 \text{ bbl/min}$$

Therefore: If one minute is required to shut-in the well, a pit gain of ' 20 bbl occurs in addition to the gain incurred while drilling the 20-ft section.

Example: Dh — 9-5/8 in. casing — 43.5 lb/ft = 8.755 in. ID Mud weight = 10.5 ppg

$$\text{psi/bbl} = \frac{1029.4}{8.755^2} \times 0.052 \times 10.5 \text{ ppg}$$

$$\begin{aligned}\text{psi/bbl} &= 13.429872 \times 0.052 \times 10.5 \text{ ppg} \\ \text{psi/bbl} &= 7.33\end{aligned}$$

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:

$$\begin{aligned}\text{FP, psi} &= 13.5 \text{ ppg} \times 0.052 \times 12,500 \text{ ft} \\ \text{FP} &= 8775 \text{ psi}\end{aligned}$$

Determine oil hydrostatic pressure:

$$\begin{aligned}\text{psi} &= (0.5 \times 8.33) \times 0.052 \times 12,500 \text{ ft} \\ \text{psi} &= 2707\end{aligned}$$

Determine surface pressure:

$$\begin{aligned}\text{Surface pressure, psi} &= 8775 \text{ psi} - 2707 \text{ psi} \\ \text{Surface pressure} &= 6068 \text{ psi}\end{aligned}$$

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:

$$\text{Drill pipe length, ft} = (\text{required drill pipe weight, lb}) \div (\text{drill pipe weight, lb/ft} \times \text{factor buoyancy})$$

$$\text{Drill pipe length, ft} = 55,094 \text{ lb} \div (19.5 \text{ lb/ft} \times 0.8092)$$

$$\text{Drill pipe length, ft} = 3492 \text{ ft}$$

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 pressure, psi = (weight of one stand of collars, lb) ÷ (area of drill collars, sq in.)

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 = (147 lb/ft x 92 ft) ÷ (8² x 0.7854)

Minimum surface pressure, psi = 13,524 ÷ 50.2656 sq in.

Minimum surface pressure = 269 psi

Height Gain From Stripping into Influx

$$\text{Height, ft} = \frac{L(Cdp + Ddp)}{Ca}$$

where L = length of pipe stripped, ft

Cdp = capacity of drill pipe, drill collars, or tubing, bbl/ft

Ddp = displacement of drill pipe, drill collars or tubing, bbl/ft

Ca = annular capacity, bbl/ft

Example: If 300 ft of 5.0 in. drill pipe — 19.5 lb/ft is stripped into an influx in a 12-1/4 in. hole, determine the height, ft, gained:

DATA: Drill pipe capacity = 0.01776 bbl/ft Length drill pipe stripped = 300 ft
Drill pipe displacement = 0.00755 bbl/ft Annular capacity = 0.1215 bbl/ft

Solution: Height, ft = $\frac{300(0.01776 + 0.00755)}{0.1215}$

$$\text{Height} = 62.5 \text{ ft}$$

Casing Pressure Increase From Stripping Into Influx

psi = (gain in height, ft) x (gradient of mud, psi/ft — 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

$$\text{psi} = 62.5 \text{ ft} \times (0.65 - 0.12)$$

$$\text{psi} = 33 \text{ psi}$$

Volume of Mud to Bleed to Maintain Constant Bottomhole Pressure with a Gas Bubble Rising

With pipe in the hole: $V_{\text{mud}} = \frac{D_p \times C_a}{\text{gradient of mud, psi/ft}}$

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 ppg x 0.052) = 0.70 psi/ft
Annular capacity ($D_h = 12\text{-}1/4$ in.; $D_p = 5.0$ in.) = 0.1215 bbl/ft

$$V_{\text{mud}} = \frac{100 \text{ psi} \times 0.1215 \text{ bbl/ft}}{0.702 \text{ psi/ft}}$$

$$V_{\text{mud}} = 17.3 \text{ bbl}$$

With no pipe in the hole: $V_{\text{mud}} = \frac{D_p \times C_h}{\text{gradient of mud, psi/ft}}$

Example: Casing pressure increase per step = 100 psi
Gradient of mud (13.5 ppg x 0.052) = 0.702 psi/ft
Hole capacity (12-1/4 in.) = 0.1458 bbl/ft

$$V_{\text{mud}} = \frac{100 \text{ psi} \times 0.1458 \text{ bbl/ft}}{0.702 \text{ psi/ft}}$$

$$V_{\text{mud}} = 20.77 \text{ bbl}$$

Maximum Allowable Surface Pressure (MASP) Governed by the Formation

MASP, psi = (maximum allowable — mud wt, in use,) 0.052 x casing shoe TVD, ft
(mud wt, ppg ppg)

Example: Maximum allowable mud weight = 15.0 ppg (from leak-off test data)
Mud weight = 12.0 ppg
Casing seat TVD = 8000 ft

$$\text{MASP, psi} = (15.0 - 12.0) \times 0.052 \times 8000$$
$$\text{MASP} = 1248 \text{ psi}$$

Maximum Allowable Surface Pressure (MASP) Governed by Casing Burst Pressure

MASP = (casing burst x safety) — (mud wt in — mud wt outside) x 0.052 x casing, shoe
(pressure, psi factor) (use, ppg casing, ppg TVD ft)

Example: Casing — 10-3/4 in. — 51 lb/ft N-80 Casing burst pressure = 6070 psi

Casing setting depth = 8000 ft Mud weight in use = 12.0 ppg
Mud weight behind casing = 9.4 ppg Casing safety factor = 80%

$$\text{MASP} = (6070 \times 80\%) - [(12.0 - 9.4) \times 0.052 \times 8000]$$

$$\text{MASP} = 4856 - (2.6 \times 0.052 \times 8000)$$

$$\text{MASP} = 3774 \text{ psi}$$

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:

Pressure Chart

	Strokes	Pressure
Line 1: Reset stroke counter to "0" =	0	
Line 2: 1/2 stroke rate = 50 x 0.5 =	25	
Line 3: 3/4 stroke rate = 50 x 0.75 =	38	
Line 4: 7/8 stroke rate = 50 x 0.875 =	44	
Line 5: Kill rate speed =	50	

Strokes side: Example: kill rate speed = 50 spm

Pressure side: Example. Shut-in casing pressure (SICP) = 800 psi
 Choke line pressure loss (CLPL) = 300 psi

Divide choke line pressure loss (CLPL) by 4, because there are 4 steps on the chart:

$$\text{psi/line} = \frac{(\text{CLPL}) \text{ 300 psi}}{4} = 75 \text{ psi}$$

Pressure Chart

Strokes	Pressure
---------	----------

Line 1: Shut-in casing pressure, psi =		800
Line 2: Subtract 75 psi from Line 1 =		725
Line 3: Subtract 75 psi from Line 2 =		650
Line 4: Subtract 75 psi from Line 3 =		575
Line 5: Reduced casing pressure =		500

Maximum Allowable Mud Weight, ppg, Subsea Stack as Derived from Leak-off Test Data

$$\text{Maximum allowable mud weight (ppg)} = \frac{(\text{leak-off test pressure, psi})}{0.052 \times (\text{TVD, ft RKB})} + (\text{mud wt in use, ppg})$$

Example: Leak-off test pressure = 800 psi
 TVD from rotary bushing to casing shoe = 4000 ft
 Mud in use = 9.2 ppg

$$\text{Maximum allowable mud weight, ppg} = \frac{800}{0.052 \times 4000} + 9.2$$

$$\text{Maximum allowable mud weight} = 13.0 \text{ ppg}$$

Maximum Allowable Shut-in Casing (Annulus) Pressure

$$\text{MASICP} = (\text{maximum allowable mud weight} - \text{mud wt in use, ppg}) \times 0.052 \times (\text{RKB to casing shoe TVD, ft})$$

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

$$\text{MASICP} = (13.3 \text{ ppg} - 11.5 \text{ ppg}) \times 0.052 \times 4000 \text{ ft}$$

$$\text{MASICP} = 374$$

Casing Burst Pressure — Subsea Stack

Step 1 Determine the internal yield pressure of the casing from the “Dimensions and Strengths” section of cement company’s service handbook.

Step 2 Correct internal yield pressure for safety factor. Some operators use 80%; some use 75%, and others use 70%:

$$\text{Correct internal yield pressure, psi} = (\text{internal yield pressure, psi}) \times \text{SF}$$

Step 3 Determine the hydrostatic pressure of the mud in use:

NOTE: The depth is from the rotary Kelly bushing (RKB) to the mud line and includes the air gap plus the depth of seawater.

$$\text{HP, psi} = (\text{mud weight in use, ppg}) \times 0.052 \times (\text{TVD, ft from RKB to mud line})$$

Step 4 Determine the hydrostatic pressure exerted by the seawater:

$$\text{HP}_{\text{sw}} = \text{seawater weight, ppg} \times 0.052 \times \text{depth of seawater, ft}$$

Step 5 Determine casing burst pressure (CBP):

$$\text{CBP} \times (\text{corrected internal}) - (\text{HP of mud in use, psi} + \text{HP of seawater, psi}) \\ (\text{yield pressure, psi})$$

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

$$\text{Internal yield pressure} = 7430 \text{ psi}$$

Step 2 Correct internal yield pressure for safety factor:

$$\text{Corrected internal yield pressure} = 7430 \text{ psi} \times 0.80$$

$$\text{Corrected internal yield pressure} = 5944 \text{ psi}$$

Step 3 Determine the hydrostatic pressure exerted by the mud in use:

$$\text{HP of mud, psi} = 10.0 \text{ ppg} \times 0.052 \times (50 \text{ ft} + 1500 \text{ ft})$$

$$\text{HP of mud} = 806 \text{ psi}$$

Step 4 Determine the hydrostatic pressure exerted by the seawater:

$$\text{HP}_{\text{sw}} = 8.7 \text{ ppg} \times 0.052 \times 1500 \text{ ft}$$

$$\text{HP}_{\text{sw}} = 679 \text{ psi}$$

Step 5 Determine the casing burst pressure:

$$\text{Casing burst pressure, psi} = 5944 \text{ psi} - 806 \text{ psi} + 679 \text{ psi}$$

$$\text{Casing burst pressure} = 5817 \text{ psi}$$

Calculate Choke Line Pressure Loss (CLPL), Psi

$$\text{CLPL} = \frac{0.000061 \times \text{MW, ppg} \times \text{length, ft} \times \text{GPM}^{1.86}}{\text{choke line ID, in.}^{4.86}}$$

Example: Determine the choke line pressure loss (CLPL), psi, using the following data:

DATA: Mud weight = 14.0 ppg Choke line length = 2000 ft
 Circulation rate = 225 gpm Choke line ID = 2.5 in.

$$\text{CLPL} = \frac{0.000061 \times 14.0 \text{ ppg} \times 2000 \text{ ft} \times 225^{1.86}}{2.5^{4.86}}$$

$$\text{CLPL} = \frac{40508.611}{85.899066}$$

$$\text{CLPL} = 471.58 \text{ psi}$$

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.

$$V, \text{ ft/min} = \frac{24.5 \times 225}{2.5^2}$$

$$V = 882 \text{ ft/min}$$

Adjusting Choke Line Pressure Loss for a Higher Mud Weight

$$\text{New CLPL} = \frac{\text{higher mud wt, ppg} \times \text{CLPL}}{\text{old mud weight, ppg}}$$

Example: Use the following data to determine the new estimated choke line pressure loss:

Data: Old mud weight = 13.5 ppg
 New mud weight = 15.0 ppg
 Old choke line pressure loss = 300 psi

$$\text{New CLPL} = \frac{15.0 \text{ ppg} \times 300 \text{ psi}}{13.5 \text{ ppg}}$$

$$\text{New CLPL} = 333.33 \text{ psi}$$

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:

$$\text{psi} = (450 \times 0.445) + (0.68 \times "y") \text{ psi} = 200.25 + 0.68"y"$$

Step 2 Determine hydrostatic pressure of mud column:

$$\begin{aligned} \text{psi} &= 9.0 \text{ ppg} \times 0.052 \times (60 + 450 + "y") \\ \text{psi} &= [9.0 \times 0.052 \times (60 + 450)] + (9.0 \times 0.052 \times "y") \\ \text{psi} &= 238.68 + 0.468 "y" \end{aligned}$$

Step 3 Minimum conductor casing setting depth:

$$\begin{aligned} 200.25 + 0.68"y" &= 238.68 + 0.468"y" \\ 0.68"y" - 0.468"y" &= 238.68 - 200.25 \\ 0.212"y" &= 38.43 \\ "y" &= \frac{38.43}{0.212} \\ "y" &= 181.3 \text{ ft} \end{aligned}$$

Therefore, the minimum conductor casing setting depth is 181.3 ft below the seabed.

Maximum Mud Weight with Returns Back to Rig Floor

Example: Using the following data, determine the maximum mud weight that can be used with returns back to the rig floor:

Data: Depths - Air gap = 75 ft Conductor casing psi/ft set at = 1225 ft RKB
 Depths - Water depth = 600ft Formation fracture gradient = 0.58 psi/ft
 Seawater gradient = 0.445 psi/ft

Step 1 Determine total pressure at casing seat:

$$\begin{aligned} \text{psi} &= [0.58 (1225 - 600 - 75)] + (0.445 \times 600) \\ \text{psi} &= 319 + 267 \\ \text{psi} &= 586 \end{aligned}$$

Step 2 Determine maximum mud weight:

$$\begin{aligned} \text{Max mud wt} &= 586 \text{ psi} \div 0.052 \div 1225 \text{ ft} \\ \text{Max mud wt} &= 9.2 \text{ ppg} \end{aligned}$$

Reduction in Bottomhole Pressure if Riser is Disconnected

Example: Use the following data and determine the reduction in bottom-hole pressure if the riser is disconnected:

Data: Air gap = 75 ft Water depth = 700 ft
Seawater gradient = 0.445 psi/ft Well depth = 2020 ft RKB
Mud weight = 9.0 ppg

Step 1 Determine bottomhole pressure:

$$\text{BHP} = 9.0 \text{ ppg} \times 0.052 \times 2020 \text{ ft}$$
$$\text{BHP} = 945.4 \text{ psi}$$

Step 2 Determine bottomhole pressure with riser disconnected:

$$\text{BHP} = (0.445 \times 700) + [9.0 \times 0.052 \times (2020 - 700 - 75)]$$
$$\text{BHP} = 311.5 + 582.7$$
$$\text{BHP} = 894.2 \text{ psi}$$

Step 3 Determine bottomhole pressure reduction:

$$\text{BHP reduction} = 945.4 \text{ psi} - 894.2 \text{ psi}$$
$$\text{BHP reduction} = 51.2 \text{ psi}$$

Bottomhole Pressure When Circulating Out a Kick

Example: Use the following data and determine the bottomhole pressure when circulating out a kick:

Data: Total depth — RKB	= 13,500 ft	Gas gradient	= 0.12 psi/ft
Height of gas kick in casing	= 1200 ft	Kill weight mud	= 12.7 ppg
Original mud weight	= 12.0 ppg	Pressure loss in annulus	= 75 psi
Choke line pressure loss	= 220 psi	Air gap	= 75 ft
Annulus (casing) pressure	= 631 psi	Water depth	= 1500 ft
Original mud in casing below gas	= 5500 ft		

Step 1 Hydrostatic pressure in choke line:

$$\text{psi} = 12.0 \text{ ppg} \times 0.052 \times (1500 + 75)$$
$$\text{psi} = 982.8$$

Step 2 Hydrostatic pressure exerted by gas influx:

$$\text{psi} = 0.12 \text{ psi/ft} \times 1200 \text{ ft}$$
$$\text{psi} = 144$$

Step 3 Hydrostatic pressure of original mud below gas influx:

$$\text{psi} = 12.0 \text{ ppg} \times 0.052 \times 5500 \text{ ft}$$

$$\text{psi} = 3432$$

Step 4 Hydrostatic pressure of kill weight mud:

$$\text{psi} = 12.7 \text{ ppg} \times 0.052 \times (13,500 - 5500 - 1200 - 1500 - 75)$$

$$\text{psi} = 12.7 \text{ ppg} \times 0.052 \times 5225$$

$$\text{psi} = 3450.59$$

Step 5 Bottomhole pressure while circulating out a kick:

Pressure in choke line	= 982.8	psi
Pressure of gas influx	= 144	psi
Original mud below gas in casing	= 3432	psi
Kill weight mud	= 3450.59	psi
Annulus (casing) pressure	= 630	psi
Choke line pressure loss	= 200	psi
Annular pressure loss	= $\frac{75}{8914.4}$	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	= 0.40 1 psi/ft
	Tubing hydrostatic pressure (THP)	= 326 psi
	Shut-in tubing pressure	= 2000 psi
	Tubing	= 2-7/8 in. — 6.5 lb/ft
	Tubing capacity	= 0.00579 bbl/ft
	Tubing internal yield pressure	= 7260 psi
	Kill fluid density	= 8.4 ppg

NOTE: Determine the best pump rate to use. The pump rate must exceed the rate of gas bubble migration up the tubing. The rate of gas bubble migration, ft/hr, in a shut-in well can be determined by the following formula:

$$\text{Rate of gas migration, ft/hr} = \frac{\text{increase in pressure per/hr, psi}}{\text{completion fluid gradient, psi/ft}}$$

Solution: Calculate the maximum allowable tubing (surface) pressure (MATP) for formation fracture:

a) MATP, initial, with influx in the tubing:

$$\text{MATP, initial} = (\text{fracture gradient, psi/ft} \times \text{depth of perforations, ft}) - (\text{tubing hydrostatic pressure, psi})$$

$$\text{MATP, initial} = (0.862 \text{ psi/ft} \times 6480 \text{ ft}) - 326 \text{ psi}$$

$$\text{MATP, initial} = 5586 \text{ psi} - 326 \text{ psi}$$

$$\text{MATP, initial} = 5260 \text{ psi}$$

b) MATP, final, with kill fluid in tubing:

$$\text{MATP, final} = (\text{fracture gradient, psi/ft} \times \text{depth of perforations, ft}) - (\text{tubing hydrostatic pressure, psi})$$

$$\text{MATP, final} = (0.862 \times 6480) - (8.4 \times 0.052 \times 6480)$$

$$\text{MATP, final} = 5586 \text{ psi} - 2830 \text{ psi}$$

$$\text{MATP, final} = 2756 \text{ psi}$$

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:

Plot these values as shown below:

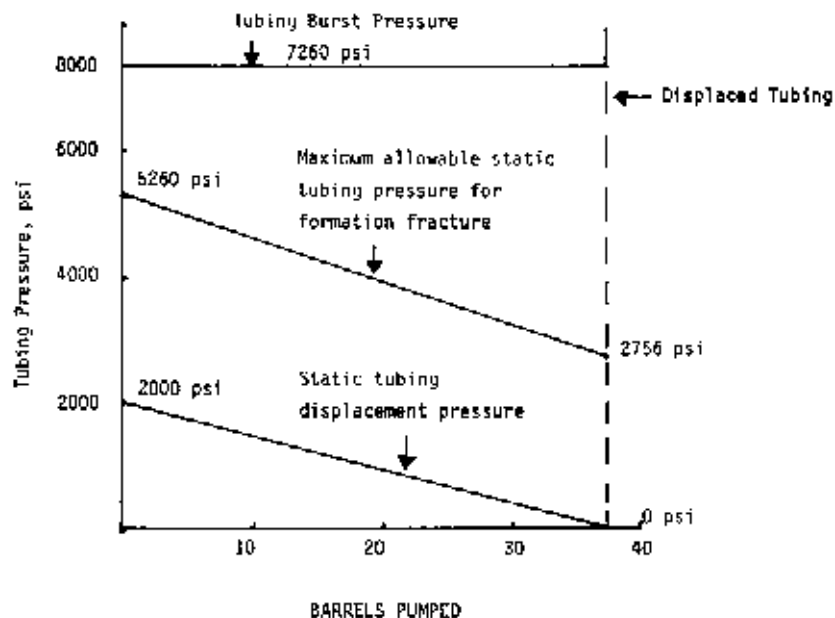


Figure 4-3. Tubing pressure profile.

Lubricate and Bleed

The lubricate and bleed method involves alternately pumping a kill fluid into the tubing or into the casing if there is no tubing in the well, allowing the kill fluid to fall, then bleeding off a volume of gas until kill fluid reaches the choke. As each volume of kill fluid is pumped into the tubing, the SITP should decrease by a calculated value until the well is eventually killed.

This method is often used for two reasons: 1) shut-in pressures approach the rated working pressure of the wellhead or tubing and dynamic pumping pressure may exceed the limits, as in the case of bullheading, and 2) either to completely kill the well or lower the SITP to a value where other kill methods can be safely employed without exceeding rated limits.

This method can also be applied when the wellbore or perforations are 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:

TVD	= 6500 ft	Depth of perforations	= 6450 ft
SITP	= 2830 psi	Tubing 6.5 lb/ft-N-80	= 2-7/8 in.
Kill fluid density	= 9.0 ppg	Wellhead working pressure	= 3000 psi
Tubing internal yield	= 10,570 psi	Tubing capacity	= 0.00579 bbl/ft (172.76 ft/bbl)

Calculations: Calculate the expected pressure reduction for each barrel of kill fluid pumped:

$\text{psi/bbl} = \text{tubing capacity, ft/bbl} \times 0.052 \times \text{kill weight fluid, ppg}$
 $\text{psi/bbl} = 172.76 \text{ ft/bbl} \times 0.052 \times 9.0 \text{ ppg}$
 $\text{psi/bbl} = 80.85$

For each one barrel pumped, the SITP will be reduced by 80.85 psi.

Calculate tubing capacity, bbl, to the perforations:

$\text{bbl} = \text{tubing capacity, bbl/ft} \times \text{depth to perforations, ft}$
 $\text{bbl} = 0.00579 \text{ bbl/ft} \times 6450 \text{ ft}$
 $\text{bbl} = 37.3 \text{ bbl}$

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.

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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):

Pc₁ & Pc₂ = circulating pressure, psi — bit nozzle pressure Loss.

4. Determine slope of line M:
$$M = \frac{\log (Pc_1 \div Pc_2)}{\log (Q_1 \div Q_2)}$$

5. Optimum pressure losses (Popt)

a) For impact force:
$$Popt = \frac{2}{M+2} \times Pmax$$

b) For hydraulic horsepower:
$$Popt = \frac{1}{M+1} \times Pmax$$

6. For optimum flow rate (Qopt):

a) For impact force:
$$Qopt, \text{ gpm} = \frac{(Popt)^{1 \div M}}{Pmax} \times Q1$$

b) For hydraulic horsepower:
$$Qopt, \text{ gpm} = \frac{(Popt)^{1 \div M}}{Pmax} \times Q1$$

7. To determine pressure at the bit (Pb):
$$Pb = Pmax - Popt$$

8. To determine nozzle area, sq in.:
$$\text{Nozzle area, sq in.} = \sqrt{\frac{Qopt^2 \times \text{MW, ppg}}{1303.8}}$$

$$10858 \times P_{\max}$$

9. To determine nozzles, 32nd in. for three nozzles:

$$\text{Nozzles} = \sqrt[3]{\frac{\text{Nozzle area, sq in.} \times 32}{3 \times 0.7854}}$$

10. To determine nozzles, 32nd in. for two nozzles:

$$\text{Nozzles} = \sqrt[2]{\frac{\text{Nozzle area, sq in.} \times 32}{2 \times 0.7854}}$$

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.:

$$\text{Nozzle area, sq in.} = \frac{17^2 + 17^2 + 17^2}{1303.8}$$

$$\text{Nozzle area, sq in.} = 0.664979$$

2. Bit nozzle pressure loss, psi (P_b):

$$P_b = \frac{420^2 \times 13.0}{10858 \times 0.6649792}$$

$$P_b = 478 \text{ psi}$$

$$P_{b_2} = \frac{275^2 \times 13.0}{10858 \times 0.6649792}$$

$$P_{b_2} = 205 \text{ psi}$$

3. Total pressure losses except bit nozzle pressure loss (P_c), psi:

$$P_c = 3000 \text{ psi} - 478 \text{ psi}$$

$$P_c = 2522 \text{ psi}$$

$$P_{c_2} = 1300 \text{ psi} - 205 \text{ psi}$$

$$P_{c_2} = 1095 \text{ psi}$$

4. Determine slope of line (M):

$$M = \frac{\log (2522 \div 1095)}{\log (420 \div 275)}$$

$$M = \frac{0.3623309}{0.1839166}$$

$$M = 1.97$$

5. Determine optimum pressure losses, psi (Popt):

a) For impact force:
$$P_{opt} = \frac{2}{1.97 + 2} \times 3000$$

$$P_{opt} = 1511 \text{ psi}$$

b) For hydraulic horsepower:
$$P_{opt} = \frac{1}{1.97 + 1} \times 3000$$

$$P_{opt} = 1010 \text{ psi}$$

6. Determine optimum flow rate (Qopt):

a) For impact force:
$$Q_{opt}, \text{ gpm} = \frac{(1511)^{1 \div 1.97}}{3000} \times 420$$

$$Q_{opt} = 297 \text{ gpm}$$

b) For hydraulic horsepower:
$$Q_{opt}, \text{ gpm} = \frac{(1010)^{1 \div 1.97}}{3000} \times 420$$

$$Q_{opt} = 242 \text{ gpm}$$

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:
$$\text{Nozzles area, sq. in.} = \sqrt{\frac{297^2 \times 13.0}{10858 \times 1489}}$$

$$\text{Nozzles area, sq. in.} = \sqrt{0.070927}$$
$$\text{Nozzle area,} = 0.26632 \text{ sq. in.}$$

b) For hydraulic horsepower:
$$\text{Nozzles area, sq. in.} = \sqrt{\frac{242^2 \times 13.0}{10858 \times 1990}}$$

Formulas and Calculations

$$\begin{aligned}\text{Nozzles area, sq. in.} &= \sqrt{0.03523} \\ \text{Nozzle area,} &= 0.1877 \text{sq. in.}\end{aligned}$$

9. Determine nozzle size, 32nd in.:

$$\begin{aligned}\text{a) For impact force:} \quad \text{Nozzles} &= \sqrt{\frac{0.26632}{3 \times 0.7854}} \times 32 \\ \text{Nozzles} &= 10.76\end{aligned}$$

$$\begin{aligned}\text{b) For hydraulic horsepower:} \quad \text{Nozzles} &= \sqrt{\frac{0.1877}{3 \times 0.7854}} \times 32 \\ \text{Nozzles} &= 9.03\end{aligned}$$

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.

$$\begin{aligned}\text{a) For impact force:} \quad 0.76 \times 3 &= 2.28 \text{ rounded to } 2 \\ \text{so: } 1 \text{ jet} &= 10/32\text{nds} \\ 2 \text{ jets} &= 11/32\text{nds}\end{aligned}$$

$$\begin{aligned}\text{b) For hydraulic horsepower:} \quad 0.03 \times 3 &= 0.09 \text{ rounded to } 0 \\ \text{so: } 3 \text{ jets} &= 9/32 \text{ nd in.}\end{aligned}$$

10. Determine nozzles, 32nd in. for two nozzles:

$$\begin{aligned}\text{a) For impact force:} \quad \text{Nozzles} &= \sqrt{\frac{0.26632}{2 \times 0.7854}} \times 32 \\ \text{Nozzles} &= 13.18 \text{ sq in.}\end{aligned}$$

$$\begin{aligned}\text{b) For hydraulic horsepower:} \quad \text{Nozzles} &= \sqrt{\frac{0.1877}{2 \times 0.7854}} \times 32 \\ \text{Nozzles} &= 11.06 \text{ sq in.}\end{aligned}$$

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): | $AV = \frac{24.5 \times Q}{Dh^2 - Dp^2}$ |
| 2. Jet nozzle pressure loss, psi (Pb): | $Pb = \frac{156.5 \times Q^2 \times MW}{[(N)^2 + (N_2)^2 + (N_3)^2]^2}$ |
| 3. System hydraulic horsepower available (Sys HHP): | $\text{SysHHP} = \underline{\text{surface, psi}} \times Q$ |

1714

4. Hydraulic horsepower at bit (HHPb):
$$\text{HHPb} = \frac{Q \times P_b}{1714}$$
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):
$$\% \text{psib} = \frac{P_b}{\text{surface, psi}} \times 100$$
7. Jet velocity, ft/sec (Vn):
$$V_n = \frac{417.2 \times Q}{(N_1)^2 + (N_2)^2 + (N_3)^2}$$
8. Impact force, lb, at bit (IF):
$$\text{IF} = \frac{(\text{MW}) (V_n) (Q)}{1930}$$
9. Impact force per square inch of bit area (IF/sq in.):
$$\text{IF/sq in.} = \frac{\text{IF} \times 1.27}{\text{bit size}^2}$$

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	HHP	= hydraulic horsepower at bit
Vn	= jet velocity, ft/sec	IF	= impact force, lb
IF/sq in. = impact force lb/sq in of bit diameter			

<i>Example:</i> Mud weight = 12.0 ppg	Circulation rate = 520 gpm
Nozzle size 1 = 12-32nd/in.	Surface pressure = 3000 psi
Nozzle size 2 = 12-32nd/in.	Hole size = 12-1/4 in.
Nozzle size 3 = 12-32nd/in.	Drill pipe OD = 5.0 in.

1. Annular velocity, ft/mm:
$$\text{AV} = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$$

$$\text{AV} = \frac{12740}{125.0625}$$

$$\text{AV} = 102 \text{ ft/mm}$$
2. Jet nozzle pressure loss:
$$P_b = \frac{156.5 \times 520^2 \times 12.0}{(12^2 + 12^2 + 12^2)^2}$$

$$P_b = 2721 \text{ psi}$$
3. System hydraulic horsepower available:
$$\text{Sys HHP} = \frac{3000 \times 520}{1714}$$

$$\text{Sys HHP} = 910$$

Formulas and Calculations

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:
$$\% \text{ psib} = \frac{2721}{3000} \times 100$$
$$\% \text{ psib} = 90.7$$
7. Jet velocity, ft/sec:
$$\text{Vn} = \frac{417.2 \times 520}{12^2 + 12^2 + 12^2}$$
$$\text{Vn} = \frac{216944}{432}$$
$$\text{Vn} = 502 \text{ ft/sec}$$
8. Impact force, lb:
$$\text{IF} = \frac{12.0 \times 502 \times 520}{1930}$$
$$\text{IF} = 1623 \text{ lb}$$
9. Impact force per square inch of bit area:
$$\text{IF/sq in.} = \frac{1623 \times 1.27}{12.25^2}$$
$$\text{IF/sq in.} = 13.7$$

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:
$$X = \frac{81600 (Kp) (n)^{0.387}}{(Dh - Dp)^n MW}$$
4. Determine critical annular velocity:
$$\text{AVc} = (X)^{\frac{1}{1.25 - n}}$$
5. Determine critical flow rate:
$$\text{GPMc} = \frac{\text{AVc} (Dh^2 - Dp^2)}{2.448}$$

24.5

Nomenclature:

n	= dimensionless	Dh	= hole diameter, in.
K	= dimensionless	Dp	= pipe or collar OD, in.
X	= dimensionless	MW	= mud weight, ppg
φ600	= 600 viscometer dial reading	Av _c	= critical annular velocity, ft/mm
φ300	= 300 viscometer dial reading	GPM _c	= critical flow rate, gpm

Example: Mud weight = 14.0 ppg Hole diameter = 8.5 in.
 φ600 = 64 Pipe OD = 7.0 in.
 φ300 = 37

1. Determine n:

$$n = 3.32 \log \frac{64}{37}$$

$$n = 0.79$$
2. Determine K:

$$K = \frac{64}{1022^{0.79}}$$

$$K = 0.2684$$
3. Determine X:

$$X = \frac{81600 (0.2684) (0.79)^{0.387}}{8.5 - 70.79 \times 14.0}$$

$$X = \frac{19967.413}{19.2859}$$

$$X = 1035$$
4. Determine critical annular velocity:

$$AV_c = (1035)^{1 \div (2 - 0.79)}$$

$$AV_c = (1035)^{0.8264}$$

$$AV_c = 310 \text{ ft/mm}$$
5. Determine critical flow rate:

$$GPM_c = \frac{310 (8.52 - 7.02)}{24.5}$$

$$GPM_c = 294 \text{ gpm}$$

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 d = exponent in general drilling equation, dimensionless
 N = rotary speed, rpm a = a constant, dimensionless

W = weight on bit, lb

“d” exponent equation: $d = \log (R \div 60N) \div \log (12W \div 1000D)$

where d = d exponent, dimensionless R = penetration rate, ft/hr
 N = rotary speed, rpm W = weight on bit, 1,000 lb
 D = bit size, in.

Example: $R = 30$ ft/hr $N = 120$ rpm $W = 35,000$ lb $D = 8.5$ in.

Solution: $d = \log [30 \div (60 \times 120)] \div \log [(12 \times 35) (1000 \times 8.5)]$
 $d = \log (30 \div 7200) \div \log (420 \div 8500)$
 $d = \log 0.0042 \div \log 0.0494$
 $d = \frac{2.377}{1.306}$
 $d = 1.82$

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:

$$d_c = d (MW_1 \div MW_2)$$

where d_c = corrected “d” exponent MW_1 = normal mud weight — 9.0 ppg
 MW_2 = actual mud weight, ppg

Example: $d = 1.64$ $MW_1 = 9.0$ ppg $MW_2 = 12.7$ ppg

Solution: $d_c = 1.64 (9.0 \div 12.7)$
 $d_c = 1.64 \times 0.71$
 $d_c = 1.16$

5. **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: $AV = \frac{24.5 \times Q}{Dh^2 - Dp^2}$

Cuttings slip velocity, ft/mm:

$$V_s = 0.45 \left(\frac{PV}{(MW)(Dp)} \right) \left[\sqrt{36,800 \div (PV \div (MW)(Dp))^2 \times (Dp)((DenP \div MW) - 1)} + 1^{-1} \right]$$

where V_s = slip velocity, ft/min PV = plastic viscosity, cps

Dp = diameter of particle, in.

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: $AV = \frac{24.5 \times 520}{12.25^2 - 5.0^2}$

$$AV = 102 \text{ ft/min}$$

$$V_s = 0.45 \left(\frac{13}{(11 \times 0.25)} \right) \left[\sqrt{36,800 \div (13 \div (11 \times 0.25))^2 \times 0.25((22 \div 11) - 1) + 1^{-1}} \right]$$

$$V_s = 0.45[4.7271 [\sqrt{36,800 \div [4.727]^2} \times 0.25 \times 1 + 1 - 1]$$

$$V_s = 2.12715 (\sqrt{412.68639} - 1)$$

$$V_s = 2.12715 \times 19.3146$$

$$V_s = 41.085 \text{ ft/mm}$$

$$\begin{aligned} \text{Cuttings net rise velocity: } & \text{Annular velocity} = 102 \text{ ft/min} \\ & \text{Cuttings slip velocity} = \underline{-41 \text{ ft/min}} \\ & \text{Cuttings net rise velocity} = 61 \text{ ft/min} \end{aligned}$$

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 (μ):

$$\mu = \left(\frac{2.4v}{D_h - D_p} \times \frac{2n + 1}{3n} \right)^n \times \frac{(200K (D_h - D_p))}{v}$$
$$V_s = \frac{(\text{DensP} - \text{MW})^{0.667} \times 175 \times \text{DiaP}}{\text{MW}^{0.333} \times \mu^{0.333}}$$

Nomenclature:

n	= dimensionless	Q	= circulation rate, gpm
K	= dimensionless	Dh	= hole diameter, in.
φ600	= 600 viscometer dial reading	DensP	= cutting density, ppg
φ300	= 300 viscometer dial reading	DiaP	= cutting diameter, in.
Dp	= pipe or collar OD, in.	v	= annular velocity, ft/min
μ	= 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	Plastic viscosity = 13 cps
	Yield point = 10 lb/100 sq. ft	Diameter of particle = 0.25 in.
	Hole diameter = 12.25 in.	Density of particle = 22.0 ppg
	Drill pipe OD = 5.0 in.	Circulation rate = 520 gpm

1. Determine n:

$$n = 3.32 \log \frac{36}{23}$$

$$n = 0.64599$$

2. Determine K:

$$K = \frac{23}{511^{0.64599}}$$

$$K = 0.4094$$

3. Determine annular velocity, ft/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:

$$\mu = \frac{(2.4 \times 102)}{12.25 - 5.0} \times \frac{2(0.64599) + 1}{3 \times 0.64599}^{0.64599} \times \frac{(200 \times 0.4094 \times (12.25 - 5))}{102}$$

$$\mu = \frac{(2448 \times 2.292)}{7.25 \times 1.938}^{0.64599} \times \frac{593.63}{102}$$

$$\mu = (33.76 \times 1.1827)^{0.64599} \times 5.82$$

$$\mu = 10.82 \times 5.82$$

$$\mu = 63 \text{ cps}$$

5. Determine slip velocity (Vs), ft/mm:

$$V_s = \frac{(22 - 11)^{0.667} \times 175 \times 0.25}{11^{0.333} \times 63^{0.333}}$$

$$V_s = \frac{4.95 \times 175 \times 0.25}{2.222 \times 3.97}$$

$$V_s = \frac{216.56}{8.82}$$

$$V_s = 24.55 \text{ ft/min}$$

6. Determine cuttings net rise velocity, ft/min:

Annular velocity	= 102	ft/min
Cuttings slip velocity	=	$\frac{24.55 \text{ ft/min}}{77.45}$
Cuttings net rise velocity	=	77.45 ft/min

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, 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:

$$P_s = \frac{(2.4 V_m)}{D_h - D_p} \times \frac{(2n + 1)^n}{3n} \times \frac{KL}{300 (D_h - D_p)}$$

Nomenclature:

n = dimensionless	D _i = drill pipe or drill collar ID, in.
K = dimensionless	D _h = hole diameter, in.
φ600 = 600 viscometer dial reading	D _p = drill pipe or drill collar OD, in
φ300 = 300 viscometer dial reading	P _s = pressure loss, psi
v = fluid velocity, ft/min	V _p = pipe velocity, ft/min
V _m = maximum pipe velocity, ft/min	L = pipe length, ft

$$v = (0.45 + 0.100)270$$
$$v = 149 \text{ ft/mm}$$

2 . Maximum pipe velocity, ft/mm: $V_m = 149 \times 1.5$
 $V_m = 224 \text{ ft/mm}$

3 . Pressure loss, psi: $P_s = \left[\frac{2.4 \times 224}{7.875 - 4.5} \times \frac{2(0.8069) + 1}{3(0.8069)} \right]^{0.8069} \times \frac{(0.522)(14300)}{300(7.875 - 4.5)}$

$$P_s = (159.29 \times 1.0798)^{0.8069} \times \frac{7464.5}{1012.5}$$

$$P_s = 63.66 \times 7.37$$

$$P_s = 469 \text{ psi surge pressure}$$

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: $v = \left[0.45 + \frac{D_p^2}{D_h^2 - D_p^2} \right] V_p$

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: $K = \frac{\phi 600}{511^n}$

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5. Calculate the shear rate (Y_m) of the mud moving around the pipe: $Y_m = \frac{2.4 \times V_m}{D_h - D_p}$

6. Calculate the shear stress (T) of the mud moving around the pipe: $T = K (Y_m)^n$

7. Calculate the pressure (P_s) decrease for the interval: $P_s = \frac{3.33 T}{D_h - D_p} \times \frac{L}{1000}$

B. Surge pressure around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$v = \left[0.45 + \frac{D_p^2}{D_h^2 - D_p^2} \right] V_p$$

2. Calculate maximum pipe velocity (V_m): $V_m = v \times 1.5$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flow rate (Q):

$$Q = \frac{V_m [(D_h)^2 - (D_p)^2]}{24.5}$$

4. Calculate the pressure loss for each interval (P_s): $P_s = \frac{0.000077 \times MW^{0.8} \times Q^{1.8} \times PV^{0.2} \times L}{(D_h - D_p)^3 \times (D_h + D_p)^{1.8}}$

C. Total surge pressures converted to mud weight:

Total surge (or swab) pressures: $\text{psi} = P_s (\text{drill pipe}) + P_s (\text{drill collars})$

D. If surge pressure is desired: $\text{SP, ppg} = P_s \div 0.052 \div \text{TVD, ft} \div \text{MW, ppg}$

E. If swab pressure is desired: $\text{SP, ppg} = P_s \div 0.052 \div \text{TVD, ft} \div \text{MW, ppg}$

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: $v = \left[0.45 + \frac{(45)^2}{7.875^2 - 4.5^2} \right] 270$

$$v = [0.45 + 0.4848] 270$$

$$v = 253 \text{ ft/mm}$$

2. Calculate maximum pipe velocity (Vm): $V_m = 253 \times 1.5$
 $V_m = 379 \text{ ft/min}$

NOTE: Determine n and K from the plastic viscosity and yield point as follows:

$$PV + YP = \phi 300 \text{ reading} \quad \phi 300 \text{ reading} + PV = \phi 600 \text{ reading}$$

Example: $PV = 60$ $YP = 20$

$$60 + 20 = 80 \text{ (}\phi 300 \text{ reading)} \quad 80 + 60 = 140 \text{ (}\phi 600 \text{ reading)}$$

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 (Ym) 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:
$$T = 0.522 (269.5)^{0.8069}$$
$$T = 0.522 \times 91.457$$
$$T = 47.74$$

7. Calculate the pressure decrease (Ps) for the interval:
$$P_s = \frac{3.33 (47.7)}{(7.875 - 4.5)} \times \frac{14,300}{1000}$$
$$P_s = 47.064 \times 14.3$$
$$P_s = 673 \text{ psi}$$

B. Around drill collars:

1. Calculate the estimated annular fluid velocity (v) around the drill collars:

$$v = [0.45 + (6.25^2 \div (7.875^2 - 6.25^2))] 270$$
$$v = (0.45 + 1.70) 270$$
$$v = 581 \text{ ft/mm}$$

2. Calculate maximum pipe velocity (Vm): $V_m = 581 \times 1.5$
 $V_m = 871.54 \text{ ft/mm}$

3. Convert the equivalent velocity of the mud due to pipe movement to equivalent flow-rate (Q):

$$Q = \frac{871.54 (7.875^2 - 6.25^2)}{24.5}$$

$$Q = \frac{20004.567}{24.5}$$

$$Q = 816.5$$

4. Calculate the pressure loss (Ps) for the interval:

$$Ps = \frac{0.000077 \times 15^{0.8} \times 816^{1.8} \times 60^{0.2} \times 700}{(7.875 - 6.25)^3 \times (7.875 + 6.25)^{1.8}}$$

$$Ps = \frac{185837.9}{504.126}$$

$$Ps = 368.6 \text{ psi}$$

C. Total pressures:

$$\begin{aligned} \text{psi} &= 672.9 \text{ psi} + 368.6 \text{ psi} \\ \text{psi} &= 1041.5 \text{ psi} \end{aligned}$$

D. Pressure converted to mud weight, ppg:

$$\begin{aligned} \text{ppg} &= 1041.5 \text{ psi} \div 0.052 \div 15,000 \text{ ft} \\ \text{ppg} &= 1.34 \end{aligned}$$

E. If surge pressure is desired:

$$\begin{aligned} \text{Surge pressure, ppg} &= 15.0 \text{ ppg} + 1.34 \text{ ppg} \\ \text{Surge pressure} &= 16.34 \text{ ppg} \end{aligned}$$

F. If swab pressure is desired:

$$\begin{aligned} \text{Swab pressure, ppg} &= 15.0 \text{ ppg} - 1.34 \text{ ppg} \\ \text{Swab pressure} &= 13.66 \text{ ppg} \end{aligned}$$

7. Equivalent Circulation Density (ECD)

1. Determine n:

$$n = \frac{3.32 \log \phi 600}{\phi 300}$$

2. Determine K:

$$K = \frac{\phi 600}{511^n}$$

3. Determine annular velocity (v), ft/mm: $v = \frac{24.5 \times Q}{Dh^2 - D^2}$

4. Determine critical velocity (Vc), ft/mm:

$$Vc = \frac{(3.878 \times 10^4 \times K)^{(1 \div (2-n))} \times (\frac{2.4}{Dh-Dp} \times \frac{2n+1}{3n})^{(n \div (2-n))}}{MW}$$

5. Pressure loss for laminar flow (Ps), psi: $Ps = (\frac{2.4v}{Dh - Dp} \times \frac{2n+1}{3n})^n \times \frac{KL}{300 (Dh - Dp)}$

6. Pressure loss for turbulent flow (Ps), psi: $Ps = \frac{7.7 \times 10^{-5} \times MW^{0.8} \times Q^{1.8} \times PV^{0.2} \times L}{(Dh - Dp)^3 \times (Dh + Dp)^{1.8}}$

7. Determine equivalent circulating density (ECD), ppg:

$$\text{ECD, ppg} = P_s - 0.052 \text{ TVD, ft} + 0\text{MW, ppg}$$

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:

$$24 + 12 = 36 \text{ Thus, 36 is the } \phi 300 \text{ reading.}$$

$$36 + 24 = 60 \text{ Thus, 60 is the } \phi 600 \text{ reading.}$$

1. Determine n:

$$n = \frac{3.321 \log 60}{36}$$

$$n = 0.7365$$

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 (V_c), ft/mm, around drill pipe:

$$V_c = \frac{(3.878 \times 10^4 \times 0.3644)^{(1 \div (2 - 0.7365))}}{12.5} \times \left(\frac{2.4}{8.5 - 5.0} \times \frac{2(0.7365) + 1}{3(0.7365)} \right)^{(0.7365 \div (2 - 0.7365))}$$

$$V_c = (1130.5)^{0.791} \times (0.76749)^{0.5829}$$

$$V_c = 260 \times 0.857$$

$$V_c = 223 \text{ ft/mm}$$

4b. Determine critical velocity (V_c), ft/mm, around drill collars:

$$V_c = \frac{(3.878 \times 10^4 \times 0.3644)^{(1 \div (2 - 0.7365))}}{12.5} \times \left(\frac{2.4}{8.5 - 6.5} \times \frac{2(0.7365) + 1}{3(0.7365)} \right)^{(0.7365 \div (2 - 0.7365))}$$

$$V_c = (1130.5)^{0.791} \times (1.343)^{0.5829}$$

$$V_c = 260 \times 1.18756$$

$$V_c = 309 \text{ ft/mm}$$

Therefore: Drill pipe: 207 ft/mm (v) is less than 223 ft/mm (V_c), Laminar flow, so use Equation 5 for pressure loss.

Drill collars: 327 ft/mm (v) is greater than 309 ft/mm (V_c) turbulent flow, so use Equation 6 for pressure loss.

5. Pressure loss opposite drill pipe:

$$P_s = \left[\frac{2.4 \times 207}{8.5 - 5.0} \times \frac{2(0.7365) + 1}{3(0.7365)} \right]^{0.7365} \times \frac{0.3644 \times 11,300}{300(8.5 - 5.0)}$$

$$P_s = \left[\frac{2.4 \times 207}{8.5 - 5.0} \times \frac{2(0.7365) + 1}{3(0.7365)} \right]^{0.7365} \times \frac{3.644 \times 11,300}{300(8.5 - 5.0)}$$

$$P_s = (141.9 \times 1.11926)^{0.7365} \times 3.9216$$

$$P_s = 41.78 \times 3.9216$$

$$P_s = 163.8 \text{ psi}$$

6. Pressure loss opposite drill collars:

$$P_s = \frac{7.7 \times 10^{-5} \times 12.5^{0.8} \times 400^{1.8} \times 24^{0.2} \times 700}{(8.5 - 6.5)^3 \times (8.5 + 6.5)^{1.8}}$$

$$P_s = \frac{37056.7}{8 \times 130.9}$$

$$P_s = 35.4 \text{ psi}$$

$$\begin{aligned} \text{Total pressure losses:} \quad \text{psi} &= 163.8 \text{ psi} + 35.4 \text{ psi} \\ \text{psi} &= 199.2 \text{ psi} \end{aligned}$$

7. Determine equivalent circulating density (ECD), ppg:

$$\text{ECD, ppg} = 199.2 \text{ psi} \div 0.052 \div 12,000 \text{ ft} + 12.5 \text{ ppg}$$

$$\text{ECD} = 12.82 \text{ ppg}$$

9. Fracture Gradient Determination - Surface Application

Method 1: Matthews and Kelly Method

$$F = P/D + K_i \sigma/D$$

where F = fracture gradient, psi/ft

P = formation pore pressure, psi

σ = matrix stress at point of interest, psi

D = depth at point of interest, TVD, ft

K_i = 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 σ as follows: $\sigma = S - P$
3. Determine the depth for determining K_i by: $D = \frac{\sigma}{0.535}$.
4. From Matrix Stress Coefficient chart, determine K_i :

4. From Matrix Stress Coefficient chart, determine K_i :

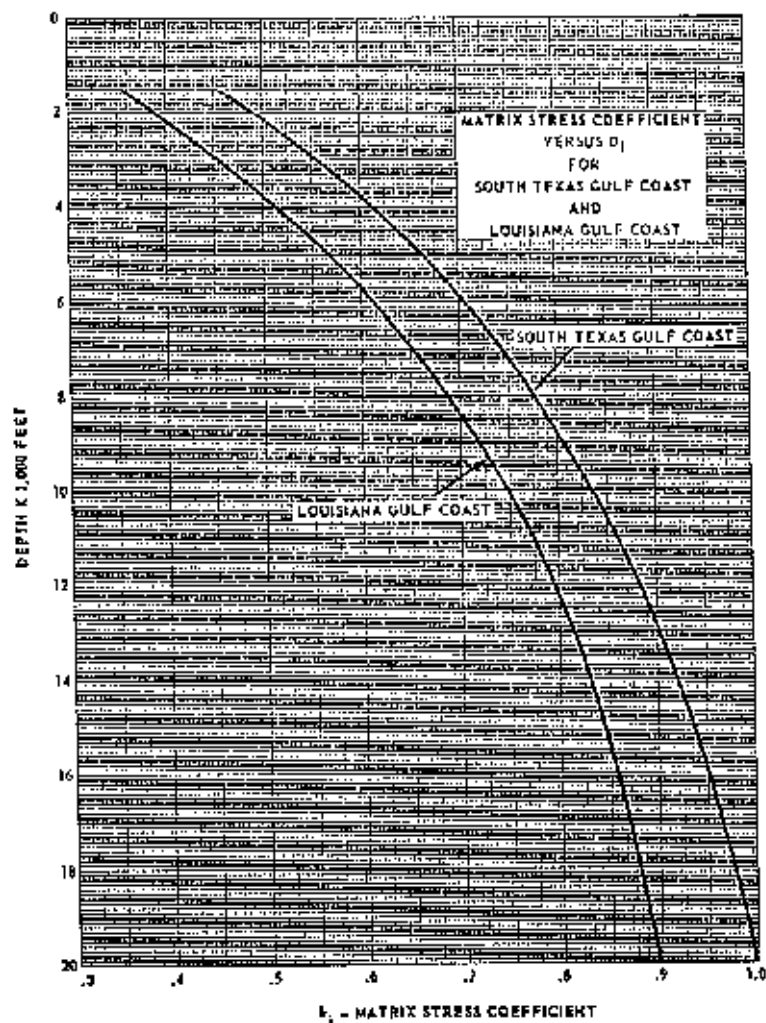


Figure 5-1. Matrix stress coefficient chart

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: $MW, \text{ ppg} = F \div 0.052$

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 = $0.92 \text{ psi/ft} \times 12,000 \text{ ft}$
Fracture pressure = 11,040 psi
7. Maximum mud density, ppg = $\frac{0.92 \text{ psi/ft}}{0.052}$
Maximum mud density = 17.69 ppg

Method 2: Ben Eaton Method

$$F = ((S \div D) - (P_f \div D)) \times (y \div (1 - y)) + (P_f \div D)$$

where S/D = overburden gradient, psi/ft

P_f/D = formation pressure gradient at depth of interest, psi/ft

y = Poisson's ratio

Procedure:

1. Obtain overburden gradient from “Overburden Stress Gradient Chart.”
2. Obtain formation pressure gradient from electric logs, density measurements, or 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 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: $F = (0.96 - 0.6243) (0.47 \div 1 - 0.47) + 0.624$
 $F = 0.336 \times 0.88679 + 0.624$
 $F = 0.29796 + 0.624$
 $F = 0.92 \text{ psi/ft}$
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 Density of seawater = 8.9 ppg
 Water depth = 2000 ft 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: $\text{HP}_{\text{sw}} = 8.9 \text{ ppg} \times 0.052 \times 2000 \text{ ft}$
 $\text{HP}_{\text{sw}} = 926 \text{ psi}$

- 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: Equivalent feet = $\frac{926 \text{ psi}}{0.92 \text{ psi/ft}}$

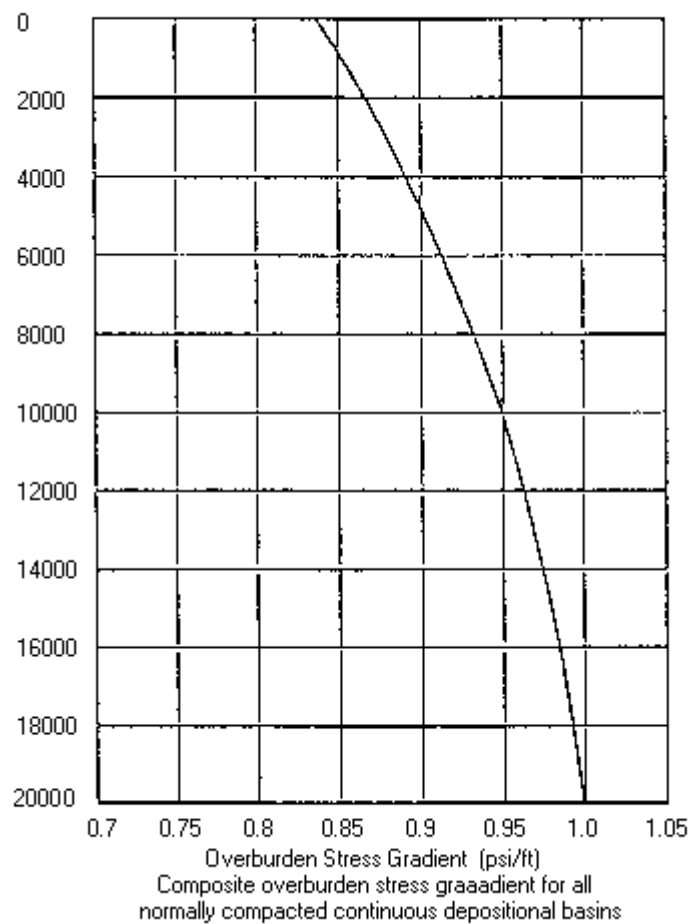


Figure 5-2. Eaton's overburden stress chart.

10. Directional Drilling Calculations

Directional Survey Calculations

The following are the two most commonly used methods to calculate directional surveys:

1. Angle Averaging Method

$$\text{North} = \text{MD} \times \sin\left(\frac{I_1 + I_2}{2}\right) \times \cos\left(\frac{A_1 + A_2}{2}\right)$$

$$\text{East} = \text{MD} \times \sin\left(\frac{I_1 + I_2}{2}\right) \times \sin\left(\frac{A_1 + A_2}{2}\right)$$

$$\text{Vert.} = \text{MD} \times \cos\left(\frac{I_1 + I_2}{2}\right)$$

2. Radius of Curvature Method

$$\text{North} = \frac{\text{MD}(\cos. I_1 - \cos. I_2)(\sin. A_2 - \sin. A_1)}{(I_2 - I_1)(A_2 - A_1)}$$

$$\text{East} = \frac{\text{MD}(\cos. I_1 - \cos. I_2)(\cos. A_2 - \cos. A_1)}{(I_2 - I_1)(A_2 - A_1)}$$

$$\text{Vert.} = \frac{\text{MD}(\sin. I_2 - \sin. I_1)}{(I_2 - I_1)}$$

where MD = course length between surveys in measured depth, ft
 I1, I2 = inclination (angle) at upper and lower surveys, degrees
 A1, A2 = direction at upper and lower surveys

Example: Use the Angle Averaging Method and the Radius of Curvature Method to calculate the following surveys:

	Survey 1	Survey 2
Depth, ft	7482	7782
Inclination, degrees	4	8
Azimuth, degrees	10	35

Angle Averaging Method:

$$\text{North} = 300 \times \sin\left(\frac{4 + 8}{2}\right) \times \cos\left(\frac{10 + 35}{2}\right)$$

$$\text{North} = 300 \times \sin(6) \times \cos(22.5)$$

$$\text{North} = 300 \times .104528 \times .923879$$

$$\text{North} = 28.97 \text{ ft}$$

$$\text{East} = 300 \times \sin.\left(\frac{4+8}{2}\right) \times \sin.\left(\frac{10+35}{2}\right)$$

$$\text{East} = 300 \times \sin. (6) \times \sin. (22.5)$$

$$\text{East} = 300 \times .104528 \times .38268$$

$$\text{East} = 12.0 \text{ ft}$$

$$\text{Vert.} = 300 \times \cos.\left(\frac{4+8}{2}\right)$$

$$\text{Vert.} = 300 \times \cos. (6)$$

$$\text{Vert.} = 300 \times .99452$$

$$\text{Vert.} = 298.35 \text{ ft}$$

Radius of Curvature Method:

$$\text{North} = \frac{300(\cos. 4 - \cos. 8)(\sin. 35 - \sin. 10)}{(8 - 4)(35 - 10)}$$

$$\text{North} = \frac{300 (.99756 - .990268)(.57357 - .173648)}{4 \times 25}$$

$$\text{North} = 0.874629 \div 100$$

$$\text{North} = 0.008746 \times 57.3^2$$

$$\text{North} = 28.56 \text{ ft}$$

$$\text{East} = \frac{300(\cos. 4 - \cos. 8)(\cos. 10 - \cos. 35)}{(8 - 4)(35 - 10)}$$

$$\text{East} = \frac{300 (99756 - .99026)(.9848 - .81915)}{4 \times 25}$$

$$\text{East} = \frac{300 (0073) (.16565)}{100}$$

$$\text{East} = \frac{0.36277}{100}$$

$$\text{East} = 0.0036277 \times 57.3^2$$

$$\text{East} = 11.91 \text{ ft}$$

$$\text{Vert.} = \frac{300 (\sin. 8 - \sin. 4)}{(8 - 4)}$$

$$\text{Vert.} = \frac{300 (0.13917 - 0.069756)}{(8 - 4)}$$

$$\text{Vert.} = \frac{300 \times .069414}{4}$$

$$\text{Vert.} = \frac{300 \times 0.069414}{4}$$

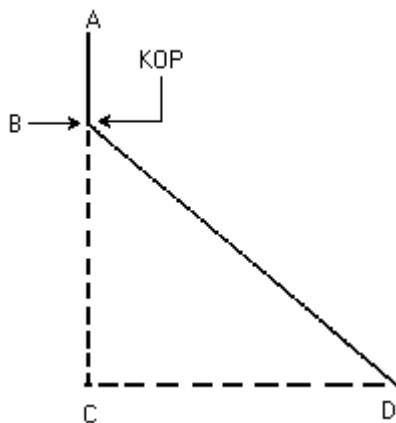
$$\text{Vert.} = 5.20605 \times 57.3$$

$$\text{Vert.} = 298.3 \text{ ft}$$

Deviation/Departure Calculation

Deviation is defined as departure of the wellbore from the vertical, measured by the horizontal distance from the rotary table to the target. The amount of deviation is a function of the drift angle (inclination) and hole depth.

The following diagram illustrates how to determine the deviation/departure:



DATA:

AB = distance from the surface location to the KOP

BC = distance from KOP to the true vertical depth (TVD)

BD = distance from KOP to the bottom of the hole (MD)

CD = Deviation/departure—departure of the wellbore from the vertical

AC = true vertical depth

AD = Measured depth

Figure 5-4. Deviation/Departure

To calculate the deviation/departure (CD), ft: $CD, \text{ ft} = \sin I \times BD$

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):

$$CD, \text{ ft} = \sin 20 \times 6000 \text{ ft}$$

$$CD, \text{ ft} = 0.342 \times 6000 \text{ ft}$$

$$CD = 2052 \text{ ft}$$

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:

$$DLS = \{\cos.^{-1}[(\cos. I1 \times \cos. I2) + (\sin. I1 \times \sin. I2) \times \cos. (A2 - A1)]\} \times (100 \div CL)$$

For metric calculation, substitute $\times (30 \div CL)$ i.e.

$$DLS = \{\cos.^{-1}[(\cos. I1 \times \cos. I2) + (\sin. I1 \times \sin. I2) \times \cos. (A2 - A1)]\} \times (30 \div CL)$$

where DLS = dogleg severity, degrees/100 ft
 CL = course length, distance between survey points, ft
 I1, I2 = inclination (angle) at upper and lower surveys, ft
 A1, A2 = direction at upper and lower surveys, degrees
 ^Azimuth = azimuth change between surveys, degrees

<i>Example:</i>	Survey 1	Survey 2
Depth, ft	4231	4262
Inclination, degrees	13.5	14.7
Azimuth, degrees	N 10 E	N 19 E

$$DLS = \{\cos.^{-1}[(\cos. 13.5 \times \cos. 14.7) + (\sin. 13.5 \times \sin. 14.7 \times \cos. (19 - 10))]\} \times (100 \div 31)$$

$$DLS = \{\cos.^{-1}[(.9723699 \times .9672677) + (.2334453 \times .2537579 \times .9876883)]\} \times (100 \div 31)$$

$$DLS = \{\cos.^{-1}[(.940542) + (.0585092)]\} \times (100 \div 31)$$

$$DLS = 2.4960847 \times (100 \div 31)$$

$$DLS = 8.051886 \text{ degrees/100 ft}$$

Method 2

This method of calculating dogleg severity is based on the tangential method:

$$DLS = \frac{100}{L [(\sin. I1 \times \sin. I2)(\sin. A1 \times \sin. A2 + \cos. A1 \times \cos. A2) + \cos. I1 \times \cos. I2]}$$

where DLS = dogleg severity, degrees/ 100 ft
 L = course length, ft
 I1, I2 = inclination (angle) at upper and lower surveys, degrees
 A1, A2 = direction at upper and lower surveys, degrees

<i>Example:</i>	Survey 1	Survey 2
Depth	4231	4262
Inclination, degrees	13.5	14.7
Azimuth, degrees	N 10 E	N 19 E

$$DLS = \frac{100}{31[(\sin.13.5 \times \sin.14.7)(\sin.10 \times \sin.19) + (\cos.10 \times \cos.119) + (\cos.13.5 \times \cos.14.7)]}$$

$$DLS = \frac{100}{30.969}$$

$$DLS = 3.229 \text{ degrees}/100 \text{ ft}$$

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: $W = 45,000 \text{ lb}$ $I = 25 \text{ degrees}$

$$P = 45,000 \times \cos 25$$

$$P = 45,000 \times 0.9063$$

$$P = 40,784 \text{ lb}$$

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:

$$TVD_2 = \cos I \times CL + TVD_1$$

where TVD_2 = new true vertical depth, ft
 TVD_1 = last true vertical depth, ft
 CL = course length — number of feet since last survey
 $\cos$ = cosine

Example: $TVD \text{ (last survey)} = 8500 \text{ ft}$ $\text{Deviation angle} = 40 \text{ degrees}$
 $\text{Course length} = 30 \text{ ft}$

Solution: $TVD_2 = \cos 40 \times 30 \text{ ft} + 8500 \text{ ft}$
 $TVD_2 = 0.766 \times 30 \text{ ft} + 8500 \text{ ft}$
 $TVD_2 = 22.98 \text{ ft} + 8500 \text{ ft}$
 $TVD_2 = 8522.98 \text{ ft}$

11. Miscellaneous Equations and Calculations

Surface Equipment Pressure Losses

$$SE_{pl} = C \times MW \times \left(\frac{Q}{100} \right)^{1.86}$$

where SE_{pl} = surface equipment pressure loss, psi Q = circulation rate, gpm
 C = friction factor for type of surface equipment W = mud weight, ppg

Type of Surface Equipment	C
1	1.0
2	0.36
3	0.22
4	0.15

Example: Surface equipment type = 3 $C = 0.22$
Mud weight = 11.8 ppg Circulation rate = 350 gpm

$$SE_{pl} = 0.22 \times 11.8 \times \left(\frac{350}{100} \right)^{1.86}$$

$$SE_{pl} = 2.596 \times (35)^{1.86}$$

$$SE_{pl} = 2.596 \times 10.279372$$

$$SE_{pl} = 26.69 \text{ psi}$$

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.

$$P = \frac{0.000061 \times 10.9 \times 6500 \times (350)^{1.86}}{4.276^{4.86}}$$

$$P = \frac{4.32185 \times 53946.909}{1166.3884}$$

$$P = 199.89 \text{ psi}$$

Annular Pressure Losses

$$P = \frac{(1.4327 \times 10^{-7}) \times MW \times L \times V^2}{D_h - D_p}$$

where P = annular pressure losses, psi MW = mud weight, ppg
 L = length, ft V = annular velocity, ft/min
 D_h = hole or casing ID, in. D_p = drill pipe or drill collar OD, in.

Example: Mud weight = 12.5 ppg Length = 6500 ft
 Circulation rate = 350 gpm Hole size = 8.5 in.
 Drill pipe OD = 5.0 in.

Determine annular velocity, ft/min: $v = \frac{24.5 \times 350}{8.5^2 - 5.0^2}$

$$v = \frac{8575}{47.25}$$

$$v = 181 \text{ ft/min}$$

Determine annular pressure losses, psi: $P = \frac{(1.4327 \times 10^{-7}) \times 12.5 \times 6500 \times 181^2}{8.5 - 5.0}$

$$P = \frac{381.36}{3.5}$$

$$P = 108.96 \text{ psi}$$

Pressure Loss Through Common Pipe Fittings

$$P = \frac{K \times MW \times Q^2}{12,031 \times A^2}$$

where P = pressure loss through common pipe fittings 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
 $K = 2.20$ 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)

$$P = \frac{0.90 \times 8.33 \times 100^2}{12,031 \times 12.5664^2}$$

$$P = \frac{74970}{1899868.3}$$

$$P = 0.03946 \text{ psi}$$

Minimum Flow-rate for PDC Bits

$$\text{Minimum flow-rate, gpm} = 12.72 \times \text{bit diameter, in.}^{1.47}$$

Example: Determine the minimum flow-rate for a 12-1/4 in. PDC bit:

$$\text{Minimum flow-rate, gpm} = 12.72 \times 12.25^{1.47}$$

$$\text{Minimum flow-rate, gpm} = 12.72 \times 39.77$$

$$\text{Minimum flow-rate} = 505.87 \text{ gpm}$$

Critical RPM: RPM to Avoid Due to Excessive Vibration (Accurate to Approximately 15%)

$$\text{Critical RPM} = \frac{33055}{L, \text{ ft}^2} \times \sqrt{\text{OD, in.}^2 + \text{ID, in.}^2}$$

Example: L = length of one joint of drill pipe = 31 ft
OD = drill pipe outside diameter = 5.0 in.
ID = drill pipe inside diameter = 4.276 in.

$$\text{Critical RPM} = \frac{33055}{312} \times \sqrt{5.0^2 + 4.276^2}$$

$$\text{Critical RPM} = \frac{33055}{961} \times \sqrt{43.284}$$

$$\text{Critical RPM} = 34.3965 \times 6.579$$

$$\text{Critical RPM} = 226.296$$

NOTE: As a rule of thumb, for 5.0 in. drill pipe, do not exceed 200 RPM at any depth.

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APPENDIX A

Table A-1
CAPACITY AND DISPLACEMENT
(English System)
DRILL PIPE

Size OD	Size ID	WEIGHT	CAPACITY	DISPLACEMENT
in.	in.	lb/ft	bbl/ft	bbl/ft
2-3/8	1.815	6.65	0.01730	0.00320
2-7/8	2.150	10.40	0.00449	0.00354
3-1/2	2.764	13.30	0.00742	0.00448
3-1/2	2.602	15.50	0.00658	0.00532
4	3.340	14.00	0.01084	0.00471
4-1/2	3.826	16.60	0.01422	0.00545
4-1/2	3.640	20.00	0.01287	0.00680
5	4.276	19.50	0.01766	0.00652
5	4.214	20.50	0.01730	0.00704
5-1/2	4.778	21.90	0.02218	0.00721
5-1/2	4.670	24.70	0.02119	0.00820
5-9/16	4.859	22.20	0.02294	0.00712
6-5/8	5.9625	25.20	0.03456	0.00807

Table A-2
HEAVY WEIGHT DRILL PIPE AND DISPLACEMENT

Size OD	Size ID	WEIGHT	CAPACITY	DISPLACEMENT
in.	in.	lb/ft	bbl/ft	bbl/ft

Formulas and Calculations

3-1/2	2.0625	25.3	0.00421	0.00921
4	2.25625	29.7	0.00645	0.01082
4-1/2	2.75	41.0	0.00743	0.01493
5	3.0	49.3	0.00883	0.01796

Additional capacities, bbl/ft, displacements, bbl/ft and weight, lb/ft can be determined from the following:

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

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

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

Table A-3
CAPACITY AND DISPLACEMENT
(Metric System)
DRILL PIPE

Size OD	Size ID	WEIGHT	CAPACITY	DISPLACEMENT
in.	in.	lb/ft	ltrs/ft	ltrs/ft
2-3/8	1.815	6.65	1.67	1.19
2-7/8	2.150	10.40	2.34	1.85
3-1/2	2.764	13.30	3.87	2.34
3-1/2	2.602	15.50	3.43	2.78
4	3.340	14.00	5.65	2.45
4-1/2	3.826	16.60	7.42	2.84
4-1/2	3.640	20.00	6.71	3.55
5	4.276	19.50	9.27	3.40
5	4.214	20.50	9.00	3.67
5-1/2	4.778	21.90	11.57	3.76
5-1/2	4.670	24.70	11.05	4.28
5-9/16	4.859	22.20	11.96	3.72
6-5/8	5.965	25.20	18.03	4.21

Table A-4
DRILL COLLAR CAPACITY AND DISPLACEMENT

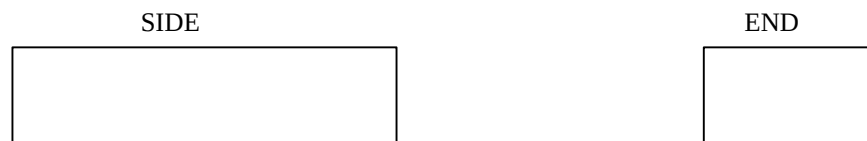
	I.D.	1½"	1¾"	2"	2¼"	2½"	2¾"	3"	3¼"	3½"	3¾"	4"	4¼"
	Capacity	.0022	.0030	.0039	.0049	.0061	.0073	.0087	.0103	.0119	.0137	.0155	.0175
OD	#/ft	36.7	34.5	32.0	29.2								
4"	Disp.	.0133	.0125	.0116	.0106								
4¼"	#/ft	34.7	42.2	40.0	37.5								
	Disp.	.0126	.0153	.0145	.0136								
4½"	#/ft	48.1	45.9	43.4	40.6								
	Disp.	.0175	.0167	.0158	.0148								
4¾"	#/ft	54.3	52.1	49.5	46.8	43.6							
	Disp.	.0197	.0189	.0180	.0170	.0159							
5"	#/ft	60.8	58.6	56.3	53.3	50.1							
	Disp.	.0221	.0213	.0214	.0194	.0182							
5¼"	#/ft	67.6	65.4	62.9	60.1	56.9	53.4						
	Disp.	.0246	.0238	.0229	.0219	.0207	.0194						
5½"	#/ft	74.8	72.6	70.5	67.3	64.1	60.6	56.8					
	Disp.	.0272	.0264	.0255	.0245	.0233	.0221	.0207					
5¾"	#/ft	82.3	80.1	77.6	74.8	71.6	68.1	64.3					
	Disp.	.0299	.0291	.0282	.0272	.0261	.0248	.0234					
6"	#/ft	90.1	87.9	85.4	82.6	79.4	75.9	72.1	67.9	63.4			
	Disp.	.0328	.0320	.0311	.0301	.0289	.0276	.0262	.0247	.0231			
6¼"	#/ft	98.0	95.8	93.3	90.5	87.3	83.8	80.0	75.8	71.3			
	Disp.	.0356	.0349	.0339	.0329	.0318	.0305	.0291	.0276	.0259			
6½"	#/ft	107.0	104.8	102.3	99.5	96.3	92.8	89.0	84.8	80.3			
	Disp.	.0389	.0381	.0372	.0362	.0350	.0338	.0324	.0308	.0292			
6¾"	#/ft	116.0	113.8	111.3	108.5	105.3	101.8	98.0	93.8	89.3			
	Disp.	.0422	.0414	.0405	.0395	.0383	.0370	.0356	.0341	.0325			
7"	#/ft	125.0	122.8	120.3	117.5	114.3	110.8	107.0	102.8	98.3	93.4	88.3	
	Disp.	.0455	.0447	.0438	.0427	.0416	.0403	.0389	.0374	.0358	.0340	.0321	
7¼"	#/ft	134.0	131.8	129.3	126.5	123.3	119.8	116.0	111.8	107.3	102.4	97.3	
	Disp.	.0487	.0479	.0470	.0460	.0449	.0436	.0422	.0407	.0390	.0372	.0354	
7½"	#/ft	144.0	141.8	139.3	136.5	133.3	129.8	126.0	121.8	117.3	112.4	107.3	

Formulas and Calculations

	Disp.	.0524	.0516	.0507	.0497	.0485	.0472	.0458	.0443	.0427	.0409	.0390
7¾"	#/ft	154.0	151.8	149.3	146.5	143.3	139.8	136.0	131.8	127.3	122.4	117.3
	Disp.	.0560	.0552	.0543	.0533	.0521	.0509	.0495	.0479	.0463	.0445	.0427
8"	#/ft	165.0	162.8	160.3	157.5	154.3	150.8	147.0	142.8	138.3	133.4	128.8
	Disp.	.0600	.0592	.0583	.0573	.0561	.0549	.0535	.0520	.0503	.0485	.0467
8¼"	#/ft	176.0	173.8	171.3	168.5	165.3	161.8	158.0	153.8	149.3	144.4	139.3
	Disp.	.0640	.0632	.0623	.0613	.0601	.0589	.0575	.0560	.0543	.0525	.0507
8½"	#/ft	187.0	184.8	182.3	179.5	176.3	172.8	169.0	164.8	160.3	155.4	150.3
	Disp.	.0680	.0672	.0663	.0653	.0641	.0629	.0615	.0600	.0583	.0565	.0547
8¾"	#/ft	199.0	196.8	194.3	191.5	188.3	184.8	181.0	176.8	172.3	167.4	162.3
	Disp.	.0724	.0716	.0707	.0697	.0685	.0672	.0658	.0643	.0627	.0609	.0590
9"	#/ft	210.2	207.9	205.6	202.7	199.6	196.0	192.2	188.0	183.5	178.7	173.5
	Disp.	.0765	.0757	.0748	.0738	.0726	.0714	.0700	.0685	.0668	.0651	.0632
10"	#/ft	260.9	258.8	256.3	253.4	250.3	246.8	242.9	238.8	234.3	229.4	224.2
	Disp.	.0950	.0942	.0933	.0923	.0911	.0898	.0884	.0869	.0853	.0835	.0816
												.0796

1. Tank Capacity Determinations

Rectangular Tanks with Flat Bottoms



$$\text{Volume, bbl} = \frac{\text{length, ft} \times \text{width, ft} \times \text{depth, ft}}{5.61}$$

Example 1: Determine the total capacity of a rectangular tank with flat bottom using the following data:

Length = 30 ft Width = 10 ft Depth = 8 ft

$$\text{Volume, bbl} = \frac{30 \text{ ft} \times 10 \text{ ft} \times 8 \text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{2400}{5.61}$$

$$\text{Volume} = 427.84 \text{ bbl}$$

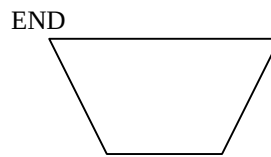
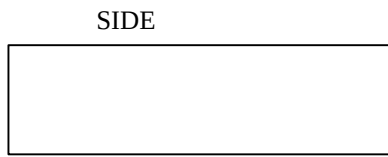
Example 2: Determine the capacity of this same tank with only 5-1/2 ft of fluid in it:

$$\text{Volume, bbl} = \frac{30 \text{ ft} \times 10 \text{ ft} \times 5.5 \text{ ft}}{5.61}$$

$$\text{Volume, bbl} = \frac{1650}{5.61}$$

$$\text{Volume} = 294.12 \text{ bbl}$$

Rectangular Tanks with Sloping Sides:



$$\text{Volume bbl} = \frac{\text{length, ft} \times [\text{depth, ft} (\text{width}_1 + \text{width}_2)]}{5.62}$$

Example: Determine the total tank capacity using the following data:

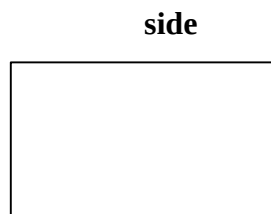
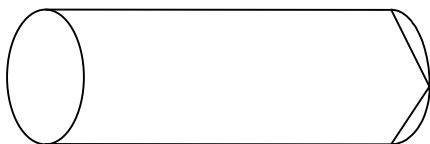
Length = 30 ft Width, (top) = 10 ft Depth = 8 ft Width₂ (bottom) = 6 ft

$$\text{Volume, bbl} = \frac{30 \text{ ft} \times [8 \text{ ft} \times (10 \text{ ft} + 6 \text{ ft})]}{5.62}$$

$$\text{Volume, bbl} = \frac{30 \text{ ft} \times 128}{5.62}$$

$$\text{Volume} = 683.3 \text{ bbl}$$

Circular Cylindrical Tanks:



$$\text{Volume, bbl} = \frac{3.14 \times r^2 \times \text{height, ft}}{5.61}$$

Example: Determine the total capacity of a cylindrical tank with the following dimensions:

Height = 15 ft Diameter = 10 ft

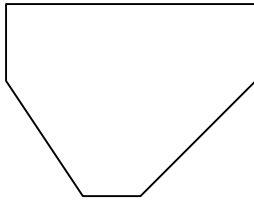
NOTE: The radius (r) is one half of the diameter: $r = \frac{10}{2} = 5$

$$\text{Volume, bbl} = \frac{3.14 \times 5 \text{ ft}^2 \times 15 \text{ ft}}{5.61}$$

$$\text{Volume bbl} = \frac{1177.5}{5.61}$$

$$\text{Volume} = 209.89 \text{ bbl}$$

Tapered Cylindrical Tanks:



a) Volume of cylindrical section: $V_c = 0.1781 \times 3.14 \times R_c^2 \times H_c$

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 = volume of cylindrical section, bbl R_c = radius of cylindrical section, ft
 H_c = height of cylindrical section, ft V_t = volume of tapered section, bbl
 H_t = height of tapered section, ft R_b = radius at bottom, ft

Example: Determine the total volume of a cylindrical tank with the following dimensions:

Height of cylindrical section = 5.0 ft Radius of cylindrical section = 6.0 ft
 Height of tapered section = 10.0 ft Radius at bottom = 1.0 ft

Solution:

a) Volume of the cylindrical section: $V_c = 0.1781 \times 3.14 \times 6.0^2 \times 5.0$
 $V_c = 100.66$ bbl

b) Volume of tapered section: $V_t = 0.059 \times 3.14 \times 10 \text{ ft} \times (6^2 + 1^2 + 1 \times 6)$
 $V_t = 1.8526 (36 + 1 + 6)$
 $V_t = 1.8526 \times 43$
 $V_t = 79.66$ bbl

c) Total volume: $\text{bbl} = 100.66 \text{ bbl} + 79.66 \text{ bbl}$
 $\text{bbl} = 180.32$

Horizontal Cylindrical Tank:

a) Total tank capacity: $\text{Volume, bbl} = \frac{3.14 \times r^2 \times L (7.48)}{42}$

b) Partial volume;

$\text{Vol. ft}^3 = L[0.017453 \times r^2 \times \cos^{-1}(r - h \div r) - \text{sq. root}(2hr - h^2(r - h))]$

Example 1: Determine the total volume of the following tank;

Length = 30 ft Radius = 4 ft

a) Total tank capacity;

$$\text{Volume, bbl} = \frac{3.14 \times 4^2 \times 30 \times 7.48}{48}$$

$$\text{Volume, bbl} = \frac{11273.856}{48}$$

$$\text{Volume} = 234.87 \text{ bbl}$$

Example 2: Determine the volume if there are only 2 feet of fluid in this tank; (h = 2 ft)

$$\text{Volume, ft}^3 = 30 [0.017453 \times 4^2 \times \cos^{-1}(4 - (2 \div 4)) - \text{sq. root } (2 \times 2 \times 4 - 2^2) \times (4 - 2)]$$

$$\text{Volume, ft}^3 = 30 [0.279248 \times \cos^{-1}(0.5) - \text{sq. root } 12 \times (2)]$$

$$\text{Volume, ft}^3 = 30 (0.279248 \times 60 - 3.464 \times 2)$$

$$\text{Volume, ft}^3 = 30 \times 9.827$$

$$\text{Volume} = 294 \text{ ft}^3$$

To convert volume, ft³, to barrels, multiply by 0.1781.

To convert volume, ft³, to gallons, multiply by 7.4805.

Therefore, 2 feet of fluid in this tank would result in;

$$\text{Volume, bbl} = 294 \text{ ft}^3 \times 0.1781$$

$$\text{Volume} = 52.36 \text{ bbl}$$

NOTE: This is only applicable until the tank is half full (r — h). After that, calculate total volume of the tank and subtract the empty space.

The empty space can be calculated by h = height of empty space.

APPENDIX B

Conversion Factors

TO CONVERT FROM	TO	MULTIPLY BY
Area		
Square inches	Square centimetres	6.45
Square inches	Square millimetres	645+2
Square centimetres	Square inches	0.155
Square millimetres	Square inches	1.55 x 10 ⁻³

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/min	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/min	0.0238

Formulas and Calculations

Gallons/min	Cubic feet/min	0.134
Gallons/min	Litres/min	3.79
Gallons/min	Cubic meters/sec	6.309×10^{-5}
Litres/min	Cubic meters/sec	1.667×10^{-5}
Litres/min	Cubic feet/min	0.0353
Litres/min	Gallons/min	0.264

Impact Force

Pounds	Dynes	4.45×10^{-5}
Pounds	Kilograms	0.454
Pounds	Newtons	4.448
Dynes	Pounds	2.25×10^{-6}

TO CONVERT FROM	TO	MULTIPLY BY
Kilograms	Pounds	2.20
Newtons	Pounds	0.2248

Length

Feet	Meters	0.305
Inches	Millimetres	25.40
Inches	Centimetres	2.54
Centimetres	Inches	0.394
Millimetres	Inches	0.03937
Meters	Feet	3.281

Mud Weight

Pounds/gallon	Pounds/cu ft	7.48
Pounds/gallon	Specific gravity	0.120
Pounds/gallon	Grams/cu cm	0.1198
Grams/cu cm	Pounds/gallon	8.347
Pounds/cu ft	Pounds/gallon	0.134
Specific gravity	Pounds/gallon	8.34

Power

Horsepower	Horsepower (metric)	1.014
Horsepower	Kilowatts	0.746

Formulas and Calculations

Horsepower	Foot pounds/sec	550
Horsepower (metric)	Horsepower	0.986
Horsepower (metric)	Foot pounds/sec	542.5
Kilowatts	Horsepower	1.341
Foot pounds/sec	Horsepower	0.00181

Pressure

Atmospheres	Pounds/sq. in.	14.696
Atmospheres	Kgs/sq. cm	1.033
Atmospheres	Pascals	1.013×10^5
Kilograms/sq. cm	Atmospheres	0.9678
Kilograms/sq. cm	Pounds/sq. in.	14.223
Kilograms/sq. cm	Atmospheres	0.9678
Pounds/sq. in.	Atmospheres	0.680
Pounds/sq. in.	Kgs/sq. cm	0.0703
Pounds/sq. in.	Pascals	6.894×10^{-3}

TO CONVERT FROM

TO

MULTIPLY BY

Velocity

Feet/sec	Meters/sec	0.305
Feet/mm	Meters/sec	5.08×10^{-3}
Meters/sec	Feet/mm	196.8
Meters/sec	Feet/sec	3.28

Volume

Barrels	Gallons	42
Cubic centimetres	Cubic feet	3.531×10^{-3}
Cubic centimetres	Cubic inches	0.06102
Cubic centimetres	Cubic meters	10^{-6}
Cubic centimetres	Gallons	2.642×10^{-4}
Cubic centimetres	Litters	0.001
Cubic feet	Cubic centimetres	28320
Cubic feet	Cubic inches	1728
Cubic feet	Cubic meters	0.02832
Cubic feet	Gallons	7.48
Cubic feet	Litters	28.32
Cubic inches	Cubic centimetres	16.39
Cubic inches	Cubic feet	5.787×10^{-4}
Cubic inches	Cubic meters	1.639×10^{-5}

Formulas and Calculations

Cubic inches	Gallons	4.329×10^{-3}
Cubic inches	Litres	0.01639
Cubic meters	Cubic centimetres	10^6
Cubic meters	Cubic feet	35.31
Cubic meters	Gallons	264.2
Gallons	Barrels	0.0238
Gallons	Cubic centimetres	3785
Gallons	Cubic feet	0.1337
Gallons	Cubic inches	231
Gallons	Cubic meters	3.785×10^{-4}
Gallons	Litres	3.785

Weight

Pounds	Tons (metric)	4.535×10^{-4}
Tons (metric)	Pounds	2205
Tons (metric)	Kilograms	1000

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