Formula Question Workbook

Well Control Pro

The following Formula Question Workbook has been designed to familiarize students with IADC requirements for achieving well control mathematical solutions. The IADC Formula Sheets are located at the end of this workbook. The solution set is found at **https://www.youtube.com/@WellControlPro.**

_Rounding Rules

a. Rounding Rule #1 **Kill Mud Weight↑**, round up to the next tenth of a pound per gallon
   i. What is the correct KMW for 15.14442 ppg?
   ii. Whis is the correct KMW for 12.2001?
b. Rounding rule #2 **Pressure Limits↓**, round down to the next tenth of pound per gallon or psi
   i. What is the correct Pressure Limit for 11.8822 ppg?
   ii. What is the correct Pressure Limit for 15.99999?
   iii. What is the Fracture Pressure Limit for 5,388.9756 psi?
   iv. What is the MAASP Limit for 6,822.99999 psi?
c. Rounding Rule #3 **Pressure Reduction Schedule↓**, round down to the whole number.
   i. What is the Pressure Reduction for 91.123 psi/step?
   ii. What is the Pressure Reduction for 17.999 psi/100 strokes?

Form 1 Usable Fluid Volume Per Bottle (gal/bottle)

Question 1: An accumulator bottle has a capacity of 10 gallons. The nitrogen pre-charge pressure is 1,000 psi. When the charge pumps have filled the tank with hydraulic fluid, the nitrogen pressure is 3,000 psi. Calculate the volume of hydraulic fluid which has been recovered from the tank once the nitrogen pressure is reduced to 1,200 psi.

Form 2 Minimum Fluid Required for Accumulator Unit (gal)

Question 2: With a safety factor of 1.5, how much closing fluid is required for this 3-Ram stack?

Hint: Recommend developing a small table to minimize mistakes.

Pipe Ram#2 Closing volume = 8 gal, Opening volume = 7.5 gal; Blind Ram Opening volume = 7.5 gal, Closing volume = 8.0 gal; Annular Preventer Closing volume = 16 gal, Opening volume = 15.8 gal; Pipe Ram #1 Closing volume = 8.0 gal, Opening volume = 7.5 gal; HCR Closing volume = 0.6 gal, Opening volume = 0.5 gal.

BOP Component	Close Volume (gal)	Open Volume (gal)

Form 3 Minimum Number of 10-Gal Accumulator Bottles Needed (bottles)

Question 3: How many ten-gallon bottles would be needed for an Accumulator unit of 61 gallons and 5 usable gallons per bottle?

Form 4 Additional Mud Returned by Slug (Additional Pit Gain)

Question 4: A 50 bbl slug is pumped with the following parameters:

- Drillpipe capacity is equal to 0.01776 barrels per foot
- Slug weight is equal to 16.2 ppg
- Mud weight is equal to 15.2 ppg
- Well Depth is equal to 12,335 feet Measured Depth and 12,121 feet True Vertical Depth

What is the Pit Gain in bbls?

Form 5 Total Mud Returned by Slug (Total Pit Gain)

Question 5: A 50 bbl slug is pumped into the top of the drillstring. The current mud weight is 12.0 ppg. The slug weight is 15.1 ppg. What is the total pit gain from the pumped slug?

Form 6 Level Drop After Pumping Slug (Drop in Footage)

Question 6: A 15 barrel, 13 ppg slug has been pumped into the drillpipe. How far down will the top of the slug be located?

- Drill Pipe capacity is equal to 0.01776 barrels per foot
- Casing internal diameter is equal to 8.636 in
- Drillpipe outer diameter is equal to 5 inches
- Current Mud Weight is equal to 11.0 ppg
- True Vertical Depth and Measured Depth are equal to 13,000 feet

Formula Question Workbook

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Form 7 Conversion of API Gravity to Specific Gravity

Question 7: Convert the following from API Gravity to Specific Gravity. What is the specific gravity of API Gravity = 30 degrees API?

Form 8 Conversion of Specific Gravity (SG) to Pounds per Gallon (ppg)

Question 8: What is the Current Mud Weight with a Specific Gravity of 1.5?

Form 9 Rectangular Tank Volume (bbls)

Question 9: What is the Volume in barrels for a Rectangular Tank with the following conditions?

- Height is equal to 15 feet
- Length is equal to 40 feet
- Width is equal to 10 feet

Form 10 Rectangular Tank Capacity (bbls/ft)

Question 10: What is the Volume in barrels per foot for a Rectangular Tank with the following conditions?

- Height is equal to 15 feet
- Length is equal to 40 feet
- Width is equal to 10 feet

Form 11 Rectangular Tank Capacity (bbls/in)

Question 11: What is the Volume in barrels per inch for a Rectangular Tank with the following conditions?

- Height is equal to 15 feet
- Length is equal to 40 feet
- Width is equal to 10 feet

Form 12 Vertical Cylindrical Tank Volume (bbls)

Question 12: What is the Volume in barrels for a Cylindrical Tank with the following conditions?

- Capacity is equal to 57 bbls/ft
- Height of Tank is equal to 15 feet

Form 13 Vertical Cylindrical Tank Volume (bbls/ft)

Question 13: What is the Volume in barrels per foot for a Vertical Cylindrical Tank with the following conditions? Tank Diameter is equal to ten feet

Form 14 Tubular Capacity (bbls/ft)

Question 14: What is the Tubular Capacity in barrels per foot with the following conditions? Tubular Internal Diameter is equal to 3.958 inches.

Form 15 Annular Capacity (bbls/ft)

Question 15: What is the annular capacity for a hole diameter which is equal to 12-1/4" and the outside diameter is equal to 6 inches?

Form 16 Open-Ended Displacement (bbls/ft)

Question 16: What is the Open-Ended Displacement for the following tubular?

- Outside Diameter is equal to 4.5 inches
- Inside Diameter is equal to 3.826 inches

Form 17 Hole Volume Change While Drilling (bbls)

Question 17: What is the hole volume change after drilling 150 feet of new hole?

- Hole Size is equal to twelve and one-quarter inch
- Hole Capacity is equal to 0.1458 barrels per foot
- Metal Displacement is equal to 0.0055 barrels per foot
- Closed-End Displacement is equal to 0.0197 barrels per foot

Form 18 Boyle's Law

Questions 18: What is the maximum fluid level we should have in the tank before we start to circulate out the kick based upon the following information?

- Hole Depth is equal to 6100 feet Measured Depth and True Vertical Depth
- Current Mud Weight is equal to 12 pounds per gallon
- Shut-in Drill Pipe Pressure is equal to 300 psi
- Initial Kick Size is equal to 10 barrels
- Maximum Surface Pressure During Kill is 800 psi
- Pit Size is equal to 150 barrels
- Pit Height is equal to 10 feet

Form 19 Gas Migration Rate (ft/hr)

Question 19: What is the gas migration rate based upon the following information?

- SICP Increase = 300 psi/hr
- Current Mud Weight = 12 ppg

Form 20 Closed-End Displacement (bbls/ft)

Question 20: What is the Closed-End Displacement if the tubular Outside Diameter is 5 in^2?

Form 21 Hole Volume Change During Trips (bbls) (Closed-In)

Question 21: What is the volume change during closed-end tripping?

- OD = 5”
- Avg Length of Stand = 93 ft
- Number of Stands = 11

Form 22 Volume of Heavy Pills (bbls)

Question 22: What size of heavy pill (or volume in bbls) would be needed for a horizontal well which requires 200 psi overburden pressure?

- Heavy pill = 16.0 ppg.
- Current mud weight = 14.5 ppg.
- Hole capacity = 0.0947 bbl/ft.

Form 23 Length of Wet Pipe Pulled Before Fill-up for Desired Pressure Drop (ΔP) ($Length_{ft}$)

Question 23: What is the length of wet pipe which can be pulled before a 75 psi drop in pressure is reached and must be filled up?

- Hole Diameter = 12-1/4”
- Pipe OD = 5”
- Annular Capacity =0.1215 bbls/ft
- Current Mud Weight = 12 ppg
- DP Capacity = 0.01776 bbls/ft
- DP Displacement = 0.0065 bbls/ft

Form 24 Length of Dry Pipe Pulled Before Fill-up for Desired Pressure Drop (ΔP) ($Length_{ft}$)

Question 24: What is the length of wet pipe which can be pulled before a 75 psi drop in pressure is reached and must be filled up?

- Hole Diameter = 12-1/4”
- Pipe OD = 5”
- Annular Capacity =0.1215 bbls/ft
- Current Mud Weight = 12 ppg
- DP Capacity = 0.01776 bbls/ft
- DP Displacement = 0.0065 bbls/ft

Form 25 Hydrostatic Pressure Drop Per Foot (ΔPpsi/ft) When Pulling Wet Pipe

Question 25: What is the hydrostatic pressure drop per foot when pulling wet pipe?

- Current Mud Weight = 12 ppg
- DP Capacity = 0.01776 bbls/ft
- DP Displacement = 0.0065 bbls/ft
- Annular Capacity = 0.1215 bbls/ft

Form 26 Buoyancy Factor (Unitless)

Question 26: What is the buoyancy factor for a 12 ppg mud?

Form 27 Buoyed Weight of Tubulars (Open-Ended or Same Fluid in Pipe and Annulus) (ppf)

Question 27: What is the buoyancy weight of 15.7 ppf pipe (open-ended) with same 12 ppg mud in both the drillpipe and annulus?

Form 28 Buoyed Weight of Tubulars (Closed-Ended and No Fluid in Pipe) (ppf)

Question 28: What is the buoyancy weight of a 15.7 pound per foot, 5" OD pipe, closed-ended, with the same 12 ppg mud in both pipe and annulus?

Form 29 Buoyed Weight of Tubulars (Different Fluid in Pipe and Annulus) (ppf)

Question 29: What is the buoyancy weight of a 15.7 pound per foot, 5" OD 4.276" ID pipe with 12 ppg mud in pipe and 10 ppg mud in annulus?

Form 30 Force (lbs)

Question 30: For an 10,000 pounds per square inch, 18-3/4" Annular tested to 70% of its rated working pressure, the maximum test pressure would be 7,000 pounds per square inch. Calculate the force acting on the annular preventer when tested to 7,000 pounds per square inch? Which way is the force acting?

Form 31 Pressure (psi)

Question 31: With a force of 100,000 pounds and an outer diameter of 18-3/4", determine the pressure acting below an 18-3/4" Annular Preventer?

Form 32 Hydrostatic Pressure (psi)

Question 32: What is the Hydrostatic Pressure in pounds per square inch exerted by a 12 ppg fluid in a well with TVD of 9,000 feet?

Form 33 Hydrostatic Pressure Gradient (psi/ft)

Question 33: What is the pressure gradient in psi/ft for a 12 ppg mud?

Form 34 Bottom Hole Pressure at Static Conditions (psi)

Question 34: What is the BHP in psi for a well that has been shut-in with TVD of 9,000 feet and 12 ppg mud?

Form 35 Bottom Hole Pressure at Shut-in Conditions (psi)

Question 35: What is the bottom hole pressure in pounds per square inch for a well with true vertical depth at 9,000 feet and 12 ppg mud with SIDPP = 200 psi?

Form 36 Bottom Hole Pressure During Normal Circulation (psi)

Question 36: What is the bottom hole pressure in pounds per square inch for a well with true vertical depth at 9,000 feet and 12 ppg mud with APL = 200 psi?

Form 37 Bottom Hole Pressure During Managed Pressure Drilling (MPD) (psi)

Question 37: What is the bottom hole pressure in pounds per square?

- TVD = 9,000 ft
- MW = 12 ppg
- APL = 200 psi
- SBP = 150 psi

Form 38 Fracture Pressure (psi)

Question 38: What is the bottom hole pressure in pounds per square?

- TVD = 9,000 ft
- MW = 12 ppg
- Max SP = 1550 psi

Form 39 Formation Integrity Test (psi)

Question 39: What is the fracture pressure in psi with the following parameters?

- FIT = 17.3 ppg
- MW = 12 ppg
- TVDshoe = 4,000 ft

Form 40 Formation Pressure (psi)

Question 40: What is the bottom hole pressure in pounds per square inch for a well with true vertical depth at 9,000 feet and 12 ppg mud with SIDPP = 200 psi?

Form 41 Mud Weight (ppg)

Question 41: What is the current mud weight in pounds per gallon with 5,616 psi Hydrostatic Pressure for a well which has a true vertical depth of 9000 feet? What is the current mud weight in pounds per gallon with Pressure Gradient of 0.624 psi/ft?

Form 42 Mud Weight Differential (psi)

Question 42: What is the mud weight differential for the following?

- Drill Pipe MW = 12 ppg
- Annulus MW = 10 ppg
- Well Depth = 9,000 feet TVD and MD

Form 43 ↓Equivalent MW or Fracture MW (ppg)

Question 43: What is the fracture mud weight in pounds per gallon with 1,150 psi Hydrostatic Pressure for a well which has a true vertical depth at of 4000 feet plus 12.0 ppg Mud Weight? What is the equivalent mud weight in pounds per gallon with Pressure Gradient of 0.9100 psi/ft?

Form 44 Equivalent Circulating Density (ECD) (ppg)

Question 44: What is the Equivalent Circulating Density, E.C.D. based upon the following information and rounding down?

- APL = 200 psi
- TVD = 9000 feet
- Current MW = 12 ppg

Form 45 Corrected SIDPP After Bumping the Float Open (psi)

Question 45: What is the Corrected Shut-In Drill Pipe Pressure after bumping the float open in psi knowing the following?

- $SICP_{current\text{-}psi}$ = 400 psi
- $SICP_{initial\text{-}psi}$ = 300 psi
- $SIDPP_{current\text{-}psi}$ = 250 psi

Form 46 Lag Time (sec)

Question 46: What is the expected Lag Time in seconds based on the following? Circulation Point MD = 14,335 feet

Form 47 ↓ Maximum Allowable MW (MAMW) or Frac MW (ppg)

Question 47: What is the maximum allowable mud weight (MAMW) in pounds per gallon?

- FIT = 1,150 psi
- TVD = 4,000 ft
- Test MW = 12 ppg

Form 48 ↓ Max. Allowable Annular Surf Press (MAASP) ↓ Max. Allowable Casing Pressure (MACP) (psi)

Question 48: What is the maximum allowable annular surface pressure (MAASP) for the following?

- MAMW =17.5 ppg
- CMW = 15 ppg
- TVDshoe = 4000 ft

Form 49 ↑ Kill Mud Weight (KMW) (ppg)

Question 49: What is the kill mud weight for the following conditions?

- SIDPP = 250 psi
- TVD = 9000 ft
- CMW = 12 ppg

Form 50 Initial Circulating Pressure (ICP) (psi)

Question 50: What is the Initial Circulating Pressure based on the following conditions?

- SCRP = 500 psi at 40 spm
- SIDPP = 250 psi

What is the Initial Circulation Pressure if Slow Circulating Rate Pressure is unknown?

Form 51 Final Circulating Pressure (FCP) (psi)

Question 51: What is the Final Circulating Pressure in pounds per square inch during the following conditions?

- SCRP = 500 psi at 40 spm
- KMW = 14.5 ppg
- CMW = 12 ppg

Form 52 New MAASP After Kill (psi)

Question 52: What is the New Maximum Allowable Annular Surface Pressure (MAASP) in psi with the following conditions?

- MAMW = 17.5 ppg
- KMW = 12.6 ppg
- TVDshoe = 4000 ft

Form 53 New DP from Varying Pump Rate (psi)

Question 53: What is the new Drill Pipe pressure in psi based upon the following conditions?

- Current Drill Pipe Pressure = 750 psi
- New Strokes per Minute = 30 spm
- Old Strokes per Minute = 40 spm

Form 54 New Pump Pressure with New Mud Weight (ppg)

Question 54: What is the new Drill Pipe Pressure while circulating if mud weights are varied?

- Current Drill Pipe Pressure = 750 psi
- New Mud Weight = 14.2 ppg
- Current Mud Weight = 12 ppg

Form 55 Total Pit Gain (bbls) Assuming Gas Influx in WBM

Question 55: What is the estimated total pit gain based upon the following conditions?

- Formation Pressure = 4700 psi
- Kick volume = 10 bbls
- Annular capacity = 0.1215 bbls/ft
- Kill Mud Weight = 14.2 ppg

Form 56 Maximum CP When Gas Reaches the Surface (psi) Assuming Gas Influx in WBM

Question 56: What is the estimated maximum casing pressure based upon the following conditions?

- Formation Pressure = 4700 psi
- Kick volume = 10 bbls
- Annular capacity = 0.1497 bbls/ft
- Kill Mud Weight = 14.2 ppg

Form 57 Working Margin Increment (psi/bbl)

Question 57: What is the working margin increment for the following well?

- Current Mud Weight = 12 ppg
- Annular Capacity =0.1216 bbls/ft

Form 58 Safety Margin (psi)

Question 58: What is the safety margin to be used during volumetric well control operations?

Form 59 Working Margin (psi)

Question 59: What is the working margin if a Safety Margin is selected to be 50 psi?

Form 60 Bleed Volume Due to Gas Migration (bbls)

Question 60: What is the Bleed Volume based upon the following conditions?

- Working Margin = 100 psi
- WMI = 15 psi/bbl

Form 61 Length of Kick in Annulus or Pipe (ft)

Question 61: What is the length of a kick, in feet, based upon the following conditions?

- Kick Volume = 10 bbls
- Annular Capacity = 0.1216 bbls/ft

Form 62 Overbalance Pressure (psi)

Question 62: What is the Overbalance Pressure based upon the following?

- Current SIDPP = 750 psi
- Initial SIDPP = 550 psi

Form 63 Determination of W&W Method

Question 63: What is the safest circulating well control method which can be employed for following conditions?

- Strokes from Bit to Casing Shoe = 1800 strokes
- Strokes from Surface to Bit = 1400 strokes
- Volume from Bit to Casing Shoe = 350 barrels
- Volume from Surface to Bit = 150 barrels

Form 64 Differential Pressure Across Cement Plug (psi)

Question 64: What is the differential across a 500 feet of cement plug?

- Mud Weight above the plug is 12 ppg
- Mud Weight below the plug is 14.2 ppg
- Top of plug is set at 7000 ft TVD

Form 65 ↑Riser Margin (ppg)

Question 65: What is the Riser Margin for the following conditions?

- Mean Sea Level to Mud Line = 530 ft
- Air Gap =70 feet
- Current Mud Weight = 12 ppg
- Sea Water density = 8.65 ppg
- Well Depth = 9000 ft TVD

Form 66 ↑MW with Riser Margin (ppg)

Question 66: What is the Corrected MW with Riser Margin?

- Mean Sea Level to Mud Line = 530 feet
- Air Gap = 70 feet
- Current Mud Weigh = 12 ppg
- Sea Water density = 8.65 ppg
- Well TVD = 9000 feet
- Riser Margin = 0.31 ppg

Form 67 Casing (or Choke) Pressure After Subsea Staging-Up to Speed Holding CP (SPUTS)® (psi)

Question 67: What is the Casing Pressure after Staging up with the following conditions

- Shut-in Casing Pressure = 500 psi
- Choke Line Friction loss = 100 psi

Form 68 Kill Line Pressure (KLP) (psi)

Question 68: What is the Kill Line Pressure for the following conditions?

- Choke Line of Mud Weight = 12 ppg
- Kill Line Mud Weight = 10 ppg
- Choke Line Length = 530 feet

FORMULA SHEET – FIELD UNITS

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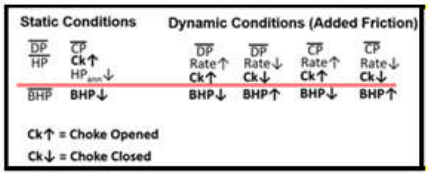
Acronyms used in the following formulas as defined in the WellSharp Acronyms document, available on the secure Provider Resources webpage. For instructions on rounding numbers when making calculations, refer to the following rounding rules and recommendations. Carry the rounded values forward into subsequent calculations.

ROUNDING RULES

- When calculating Kill Mud Weight, **ROUND UP** to the next tenth of a pound-per-gallon
  - For example; round up 15.1442 ppg to ↑15.2 ppg; round up 12.20000000001 ppg to ↑12.3 ppg.
- For Pressure Limits
  - When calculating Formation Integrity/Leak-Off Test Equivalent Mud Weight (ppg), **ROUND DOWN** to the next tenth of a pound-per-gallon
    - For example; round down 11.8822 ppg to ↓11.8 ppg; 15.9999 ppg to ↓15.9 ppg.
  - When calculating Formation Fracture Pressure or MAASP/MACP, **ROUND DOWN** to the whole number
    - For example; round down 5,388.9756 psi to ↓5,388 psi; round down 6,822.9999 psi to ↓6,822 psi.
- When calculating the Pressure Reduction Schedule, **ROUND DOWN** to a whole number
  - For example: round down 88.128 psi/step to ↓88 psi/step or round down 17.999 psi/100 stks to ↓17 psi/100 stks.
- If the Kill Mud Weight or Pressure Limits are to be used in subsequent calculations, use the rounded value in future calculations. Do not use the unrounded calculated value.

BHP Pressure Concepts



ROUNDING RECOMMENDATIONS

See Table to right where:
X = Whole number
X.X = Number with 1 decimal place
X.XX = Number with 2 decimal places
X.XXXX = Number with 4 decimal places

MEASUREMENT	UNITS	ROUNDING and ANSWER FORMAT
Depth	feet	X
Force	lbs	X
Pressure	psi	X
Pressure Reduction	psi/100 stks or psi/10 steps*	X
Pump Speed	spm	X
Pump Strokes	strks or stks	X
Tripping Speed	feet/hr	X
Mud Weight	ppg	X.X
Volume	bbls	X.X
Area	in^2	X.XXXX
Buoyancy Factor	unitless	X.XXXX
Capacity/Displacement	bbls/ft	X.XXXX
Pressure Gradient	psi/ft	X.XXXX

*10 steps = Surface to Bit strokes divided by 10.

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Section 1: BOP Closing Systems

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1. Usable Fluid Volume Per Bottle *(gal/bottle)*

$= [(\text{Precharge Press}_{psi} \div \text{Min. Operating Press}_{psi}) - (\text{Precharge Press}_{psi} \div \text{Max. Operating Press}_{psi})] \times \text{Bottle Vol}_{gal}$

Note: The Usable Volume is **5 gallons** for 3000 psi Accumulator with 1200 Minimum Operating Pressure and 1000 psi Precharge.

2. Minimum Fluid Required For Accumulator Unit *(gal)*

$\text{Min Fld}_{\text{4 Ram}} = \text{Safety Factor} \times (\text{CloseVol}_{Annular} + \text{CloseVol}_{Ram\#1} + \text{CloseVol}_{Ram\#2} + \text{CloseVol}_{Ram\#3} + \text{CloseVol}_{Ram\#4} + \text{OpenVol}_{HCR})$

$\text{Min Fld}_{\text{3 Ram}} = \text{Safety Factor} \times (\text{CloseVol}_{Annular} + \text{CloseVol}_{Ram\#1} + \text{CloseVol}_{Ram\#2} + \text{CloseVol}_{Ram\#3} + \text{OpenVol}_{HCR})$

Note: For U.S. operations, the **Safety Factor is 1.5** for a 3000 psi BOP Closing Unit with 1200 Minimum Operating Pressure and 1000 psi Precharge.

3. Minimum Number of 10 Gal Accumulator Bottles Needed *(bottles)*

$= \text{Minimum Fluid Required for Accumular Unit}_{gal} \div \text{Usable Fluid Volume Per Bottle}_{gal/bottle}$

Section 2: Slugging

4. Additional Mud Returned by Slug *(Additional Pit Gain – Small Vol) (bbls)*

$= [(\text{Slug Weight}_{ppg} \div MW_{ppg}) - 1] \times \text{Slug Volume}_{bbls}$

5. Total Mud Returned by Slug *(Total Pit Gain – Lg Vol) (bbls)*

$= (\text{Slug Weight}_{ppg} \div MW_{ppg}) \times \text{Slug Volume}_{bbls}$

6. Level Drop After Pumping Slug *(Drop in Footage) (ft)*

$= [(\text{Slug Weight}_{ppg} \div MW_{ppg}) - 1] \times \text{Slug Volume}_{bbls} \div \text{Drill Pipe Capacity}_{bbls/ft}$

Section 3: Volume, Capacity, Displacement

7. Conversion of API Gravity (°API) to Specific Gravity (SG) $= 141.5 \div (°API + 131.5)$

8. Conversion of Specific Gravity (SG) to Lbs./Gal *(ppg)* $= 8.33 \times \text{Specific Gravity}$

9. Rectangular Tank Volume *(bbls)* $= (\text{Length}_{ft} \times \text{Width}_{ft} \times \text{Height}_{ft}) \div \mathbf{5.615}$

10. Rectangular Tank Capacity *(bbls/ft)* $= (\text{Length}_{ft} \times \text{Width}_{ft}) \times \mathbf{0.178}$

11. Rectangular Tank Capacity *(bbls/in)* $= (\text{Length}_{ft} \times \text{Width}_{ft}) \times \mathbf{0.0148}$

12. Vertical Cylindrical Tank Volume *(bbls)* $= \text{Capacity}_{bbls/ft} \times \text{Height}_{ft}$

13. Vertical Cylindrical Tank Capacity *(bbls/ft)* $= \text{Tank Diameter}_{ft}^2 \times \mathbf{7.148}$

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14. Tubular Capacity *(bbls/ft)* = $ID_{in}^2 \div 1029.4$ *(ID = Internal Diameter of Tubular)*

15. Annular Capacity *(bbls/ft)* = $(D_{in}^2 - d_{in}^2) \div 1029.4$ *(D=Hole Diameter or Casing ID, d=Outside Diameter of Tubular)*

16. Open-Ended Displacement *(bbls/ft)* = $(OD_{in}^2 - ID_{in}^2) \div 1029.4$ *(OD= Outside Diameter, ID= Inside Diameter of Tubular)*

17. Hole Volume Change While Drilling *(bbls)* = $\text{Hole Cap}_{bbls/ft} - \text{DP Disp}_{bbls/ft}) \times \text{Drilled Footage}_{ft}$

Section 4: Influx (Boyle's Law)

18. Boyle's Law Formula $P_1 \times V_1 = P_2 \times V_2$ or $V_2 = (P_1 \times V_1) \div P_2$

= A. Formation Pressure_{psi} = $\text{DP Hydrostatic Pressure}_{psi} + \text{SIDPP}_{psi}$ (psi)

= **B. Total Pit Gain** $_{bbls}$ = $(\text{Form Press}_{psi} \times \text{Kick Vol}_{bbls}) \div \text{Max CP}_{psi}$ (bbls)

= **C. Additional Pit Gain**$_{bbls}$ = $\text{Total Pit Gain}_{bbls} - \text{Kick Volume}_{bbls}$ (bbls)

= D. Available Pit Vol_{bbls} = $\text{Pit Vol}_{bbls}^{*} - \text{Additional Pit Gain}_{bbls}$ (bbls)

= **E. Max. Fluid Level**$_{ft}$ = $\text{Avail Pit Vol}_{bbls} \div (\text{Pit Vol}_{bbls} \div \text{Pit Height}_{ft})$ (ft)

Note: *May be stated as "Pit Size." If unknown, Pit Vol may be calculated from $(L_{ft} \times W_{ft} \times H_{ft}) \div 5.6146\ ft^3/bbl$

19. Gas Migration Rate *(ft/hr)* = $\text{Shut-In Pressure Increase}_{psi/hr} \div (\text{Current MW}_{ppg} \times 0.052)_{psi/ft}$

Section 5: Tripping

20. Closed-End Displacement *(bbls/ft)* = $(OD_{in}^2) \div 1029.4$ *(OD= Outside Diameter)*

21. Hole Vol Change During Tripping (bbls) (Closed-End) = $[(OD_{in}^2) \div 1029.4] \times \text{Stand}^{*}_{ft/std} \times \text{No. of Stands}_{Stands}$
Note: *Stand can be estimated at 93 ft

22. Volume of Heavy Pill (bbls)
= A) Pill Ht_{ft} = $\text{Overbalance}_{psi} \div (\text{Pill Wt}_{ppg} - \text{MW}_{ppg}) \times 0.052$
= B) Vol_{bbl} = $\text{Pill Height}_{ft} \times \text{Hole Capacity}_{bbls/ft}$

23. Length of Wet Pipe Pulled Before Fill-up for Desired Pressure Drop (ΔP) (*Length*$_{ft}$)
= $(\Delta P_{psi} \times \text{Annulus Cap}_{bbl/ft}) \div [0.052 \times \text{MW}_{ppg} \times (\text{DP Cap}_{bbls/ft} + \text{DP Displ}_{bbls/ft})]$

24. Length of Dry Pipe Pulled Before Fill-up for Desired Pressure Drop (ΔP) (*Length*$_{ft}$)
= $[\Delta P_{psi} \times (\text{Annulus Cap}_{bbl/ft} + \text{DP Cap}_{bbl/ft})] \div 0.052 \times \text{MW}_{ppg} \times \text{DP Displ}_{bbls/ft}$

25. Hydrostatic Pressure Drop Per Foot ($\Delta P_{psi/ft}$) When Pulling Wet Pipe
= $0.052 \times \text{MW}_{ppg} \times [(\text{DP Cap}_{bbls/ft} + \text{DP Displ}_{bbls/ft}) \div \text{Annulus Cap}_{bbl/ft}$

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Section 6: Buoyancy

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26. Buoyancy Factor *(Unitless)* = $(65.4 - \text{Mud Weight}_{ppg}) \div 65.4$

27. Buoyed Weight of Tubulars (Open-Ended or Same Fluid in Pipe and Annulus) *(ppf)*

= $\text{Pipe Weight in Air}_{ppf} \times \text{Buoyancy Factor}$

28. Buoyed Weight of Tubulars (Closed-Ended and No Fluid in Pipe) *(ppf)*

= $\text{Pipe Weight in Air}_{ppf} - [(\text{Pipe OD}^2_{in} \times \text{Mud Weight}_{ppg}) \div 24.5]$

29. Buoyed Weight of Tubulars (Different Fluid in Pipe and Annulus) *(ppf)*

A. $\text{Pipe Wt}_{A\text{-}ppf} = \text{Pipe Wt}_{Air\text{-}ppf}$

B. $BW_{B\text{-}ppf} = [(\text{Pipe ID}_{in})^2 \times MW_{DP\text{-}ppg}] \div 24.5$

C. $BW_{C\text{-}ppf} = [(\text{Pipe OD}_{in})^2 \times MW_{Annulus\text{-}ppg}] \div 24.5$

D. $BW_{D\text{-}ppf} = (\text{Pipe Wt}_{A\text{-}ppf} + BW_{B\text{-}ppf}) - BW_{C\text{-}ppf}$

Section 7: Forces

30. Force *(lbs)* = $\text{Pressure}_{psi} \times (\text{Diameter})^2_{in^2} \times 0.7854$

31. Pressure *(psi)* = $\text{Force}_{lbs} \div (\text{Diameter})^2_{in^2} \div 0.7854$

32. Hydrostatic Pressure *(psi)* = $\text{Mud Weight}_{ppg} \times 0.052 \times \text{TVD}_{ft}$

33. Hydrostatic Pressure Gradient *(psi/ft)* = $\text{Current Mud Weight}_{ppg} \times 0.052$

Note: Normal Pressure Gradients range between 0.433 psi/ft for freshwater to 0.465 psi/ft for saltwater.

Section 8: Bottom Hole Pressure (BHP)

34. Bottom Hole Pressure at Static Conditions *(psi)* = HP_{dp} (Static)

35. Bottom Hole Pressure at Shut-In Conditions *(psi)* = HP_{dp} + SIDPP or Form Press = HP_{dp} + SIDPP or $HP_{annulus\text{-}psi}$ + SICP

36. Bottom Hole Pressure During Normal Circulation *(psi)* = HP_{dp} + APL (Annular Pressure Loss) or $BHP_{psi} = HP_{ann\text{-}psi} + APL_{psi} + CBP_{psi}$ (Chk Back Press)

37. Bottom Hole Pressure During MPD Circulation *(psi)* = HP_{dp} + APL + SBP (Surface Back Pressure or Choke Back Pressure)

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Section 9: Limits

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38. Fracture Pressure *(psi)*
$FracP_{psi} = HP_{dp} + Maximum\ Surface\ Pressure_{psi}$

39. Formation Integrity Test *(psi)*
$FIT_{psi} = 0.052 \times (FIT_{ppg} - CMW_{ppg}) \times Shoe\ TVD_{ft}$

40. Formation Pressure *(psi)*
(also referred to as Bottomhole Pressure at Shut-in)
$= Hydrostatic\ Pressure\ in\ Drill\ String_{psi} + SIDPP_{psi}$

41. Mud Weight *(ppg)*
$= Pressure_{psi} \div TVD_{ft} \div 0.052$ or $Pressure\ Gradient_{psi/ft} \div 0.052$

42. Mud Weight Differential *(psi)*
$\Delta MW_{psi} = 0.052 \times (MW_{dp} - MW_{annulus}) \times TVD_{ft}$

43. ↓ Equivalent MW (ppg) or Fracture MW *(ppg)*
$= (Max.\ Surface\ Pressure_{psi} \div TVD_{ft} \div 0.052) + Current\ Mud\ Weight_{ppg}$ or
$Max.\ Surface\ Pressure_{psi} \div 0.052 \div TVD_{ft}$

44. Equivalent Circulating Density (ECD) *(ppg)*
$= [Annular\ Pressure\ Loss_{psi}\ (APL) \div TVD_{ft} \div 0.052] + Current\ Mud\ Weight_{ppg}$
Note: $APL_{psi} = Annular\ Pressure\ Loss_{psi}$ or $Safety\ Margin_{psi}$

Section 10: Killsheet

45. Corrected SIDPP After Bumping the Float Open *(psi)*
A) $Trapped\ Pressure_{psi} = SICP_{current} - SICP_{initial}$
B) $SIDPP_{corrected} = SIDPP_{current} - Trapped\ Pressure_{psi}$

46. Lag Time *(sec)*
$Lag\ Time_{sec} = (Measured\ Depth\ of\ Circulation\ Point_{ft} \div 1000\ feet) \times (2\ seconds)$

Note: APL_{psi} = Most common well control mistake
A) Loss of control by multiple choke adjustments may be correct by stopping choke adjustments
B) Wait for the varriances to subside
C) Make additonal corrective choke adjustments as needed

47. ↓ Maximum Allowable MW (MAMW) or Frac MW *(ppg)*
$= (FIT/LOT/Max\ Surface\ Pressure_{psi} \div Shoe\ TVD_{ft} \div 0.052) + Test\ Mud\ Weight_{ppg}$

48. ↓ Max. Allowable Annular Surf Press (MAASP)
↓ Max. Allowable Casing Pressure (MACP) *(psi)*
$= (Max.\ Allowable\ MW_{ppg} - Current\ MW_{ppg}) \times Shoe\ TVD_{ft} \times 0.052$

49. ↑ Kill Mud Weight (KMW) *(ppg)*
$= (SIDPP_{psi} \div TVD_{ft} \div 0.052) + Current\ Mud\ Weight_{ppg}$

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50. Initial Circulating Density (ICP) *(psi)*

= Slow Circulating Rate Pressure$_{psi}$ *(SCRP$_{psi}$)* + SIDPP$_{psi}$
= Kill Rate Pressure$_{psi}$ *(KRP$_{psi}$)* + SIDPP

51. Final Circulating Density (FCP) *(psi)*

= Slow Circulating Rate Pressure$_{psi}$ *(SCRP$_{psi}$)* x (KMW$_{ppg}$ ÷ CMW$_{ppg}$)
Kill Rate Pressure$_{psi}$ *(KRP$_{psi}$)* x (KMW$_{ppg}$ ÷ CMW$_{ppg}$)

52. New MAASP After Kill *(psi)*

= (Max. Allowable MW$_{ppg}$ – Kill MW$_{ppg}$) x Shoe TVD$_{ft}$ x 0.052

53. New DP from Varying Pump Rate *(psi)*

= SCRP$_{psi}$ x (New SPM ÷ Old SPM)^2, **Holding $\overline{CP}$** ***(only approximate!)***

54. New Pump Pressure with New Mud Weight *(psi)*

= SCRP$_{psi}$ x (New Mud Weight ÷ Current Mud Weight) ***(only approximate!)***

Only approximate due to "round off" of the squared term
Note: **ALWAYS** hold casing pressure constant when varying pump rate

55. Total Pit Gain *(bbls)*
Assume Gas Influx in WBM

$$= 4 \times \sqrt{\frac{\text{FormP}_{psi} \times \text{Kick Vol}_{bbls} \times \text{Annular Cap}_{bbls/ft}}{\text{KMW}_{ppg}}}$$

Note: Requires a Scientific Calculator to Solve Equation

56. Max CP When Gas Reaches the Surface *(psi)*
Assume Gas Influx in WBM

$$= 2 \times \sqrt{\frac{\text{FormP}_{psi} \times \text{Kick Vol}_{bbls} \times \text{KMW}_{ppg}}{\text{Surf Annular Cap}_{bbls/ft}}}$$

Note: Requires a Scientific Calculator to Solve Equation

Section 11: Volumetric Method

57. Working Margin Increment *(psi/bbl)*

= (MW$_{ppg}$ x 0.052) ÷ Annular Capacity$_{bbls/ft}$

58. Safety Margin *(psi)*

= 50 psi or 100 psi (easy to read on gauge)

59. Working Margin *(psi)*

= 100 psi (2 x Safety Margin)

60. Bleed Volume Due to Gas Migration *(bbls)*

= Working Margin$_{psi}$ ÷ Working Margin Increment$_{psi/bbl}$

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Section 12: Barriers and Supplemental Calculations

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61.	**Length of Kick in Annulus or Pipe *(ft)***	= $\text{Kick Volume}_{bbls} \div \text{Annular or Pipe Capacity}_{bbls/ft}$
62.	**Overbalance Pressure *(psi)***	= $SIDPP_{current\text{-}psi} - SIDPP_{initial\text{-}psi}$
63.	**Determination of W&W Method**	W&W Method Preference = $Stks_{Bit\ to\ Csg\ Shoe} > Stks_{Surf\ to\ Bit}$ W&W Method Preference = $OH\ Vol_{Bit\ to\ Csg\ Shoe} > DP\ Vol_{Surf\ to\ Bit}$
64.	**Differential Pressure Across Cement Plug *(psi)***	$\Delta P_{psi} = HP_{Below\text{-}psi} - HP_{Above\text{-}psi}$ where, $HP_{Below} = FormP_{psi}$ or $0.052 \times MW_{Below\text{-}ppg} \times TVD_{Bottom\ of\ Plug\text{-}ft}$ $HP_{Above} = 0.052 \times MW_{Above\text{-}ppg} \times TVD_{Top\ of\ Plug\text{-}ft}$

Section 13: Subsea

65.	**↑Riser Margin *(ppg)***	= $\text{BHP Reduction}_{psi} \div 0.052 \div \text{Well TVD}_{Mudline\ to\ TD\ ft}$
66.	**↑MW with Riser Margin *(ppg)***	= $CMW_{ppg} + \text{Riser Margin}_{ppg}$
67.	**Casing (or Choke) Pressure After Subsea Staging-Up to Speed Holding CP (SPUTs) *(psi)***	= $SICP_{psi} - \text{Choke Line Friction Loss}_{psi}$
68.	**Kill Line Pressure- KLP *(psi)***	= $(MW_{choke\ line\text{-}ppg} - MW_{kill\ line\text{-}ppg}) \times \text{Choke Line Length}_{ft} \times 0.052$

Legend

○ - **Formula normally used on Wellsharp® Test**

▢ - **Formula requires Scientific Calculator, not normally found on Wellsharp® Test**

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