Surface gas handling system and mud gas separator design

Principles for drilling operations

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1. Summary

This technical guidance is for petroleum operating plant operators and other who have legal duties under Chapter 9 of the *Petroleum and Gas (Production and Safety) Act 2004* to engage in petroleum drilling activities.

The aim of this guidance note is to ensure that the surface gas handling system for drilling operation is fit for purpose and used within their operating limitations.

2. Surface Gas Handling System

a) In a well-controlled situation, well bore fluids are directed through the choke and kill manifold to circulate hazardous gas in a safe and controlled manner using the Mud Gas Separator.
b) The operating limits of the surface gas handling system should not be exceeded.
c) The system must take into account the design and operating criteria of the mud gas separator, the arrangement of the derrick vent line, liquid seal and emergency relief lines.
d) A well specific analysis may be necessary to ensure the system capacity is compatible with the parameters of the reservoir gas and properties of the drilling fluids.

3. Mud Gas Separator

In the oilfield, the mud gas separator is sometimes known as ‘poor boy degasser’ or ‘gas buster’. They may be vertical or horizontal in design.

A Vertical separator is normally used for high fluid throughput, while a horizontal separator provides a longer retention time and superior gas separating capacity. Internal design and configuration (e.g. blast chamber, baffle plate etc.) governs the individual efficiency of the equipment.

Performance characteristics

The limitation to the efficiency of a mud gas separator is dedicated by:

(i) Separating Capacity – the capacity to separate gas from the liquid is determined by the internal configuration and fluid dynamic characteristics of the separator. (Attachment 1)

(ii) Venting Capacity – the capacity to vent gas through the derrick vent is subject to the backpressure of the vent line and the hydrostatic head of the liquid seal. (Attachment 2)

(iii) Liquid re-entrainment Capacity – the capacity when the liquid droplets break away from a gas/liquid interface to become suspended in the gas phase. The term re-entrainment is used in separator design because it is assumed that droplets have settled to the liquid phase and are then returned to the gas phase. (Attachment 3)

It should be noted that the capacity of the separator to separate gas from the liquid may be considerably less than the capacity to vent gas within the limit of the liquid seal.

Pertinent Features

The separator should be designed to a recognised pressure vessel code. To avoid plugging by solids, hydrates or mechanical malfunction, the separator back pressure should be controlled by a liquid seal rather than conventional back pressure regulators or liquid level control valves. A pressure gauge is required to monitor the pressure in the separator vessel.

4. Emergency relief lines

In exceptional situations, well control may require displacement of the kick to continue regardless of the capacity of the mud-gas separator to handle well bore fluids. All drilling facilities should have a means of diverting flow from the choke manifold to a safe area through relief lines and isolating the mud gas separator.

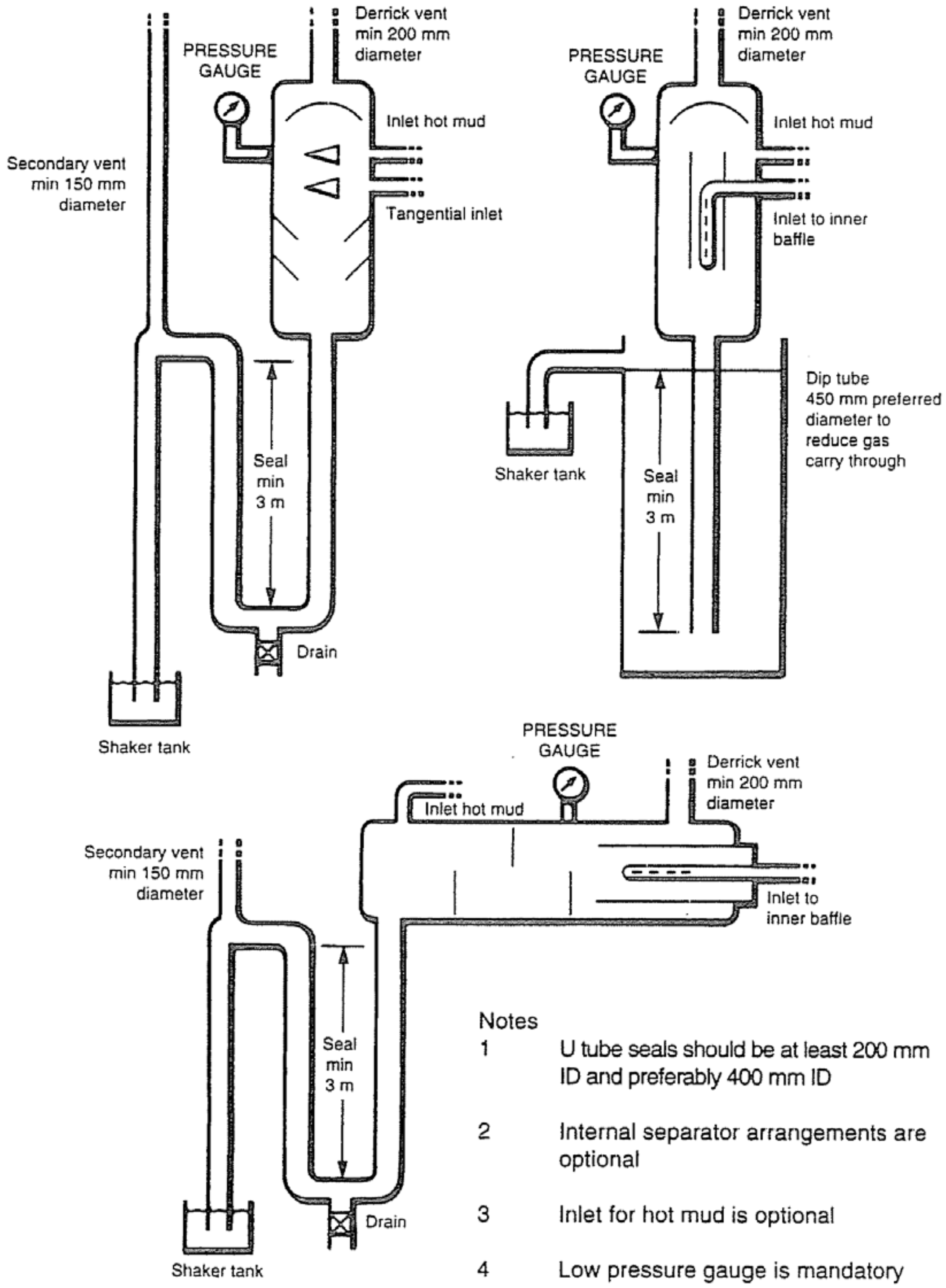
5. Well Control Procedure

As a well specific exercise, consideration should be given to establish the slow circulating rate SCR (Choke pressure) against the limiting capacities of the system for a well kill operation. The rate of delivery of reservoir fluids to the separator should be limited to the capacity that will not break the liquid seal. In extreme cases this may mean shutting in the well, or alternatively diverting the returns through the overboard line(s) if closing the well will lead to a more prolonged and potentially more problematic well control situation.

6. Instrumentation and chemical injection

Mud gas separator should be operated taking into account the risk of hydrate formation. Where necessary, a hydrate suppressant such as glycol should be employed. Alternatively, means may be provided to heat the kick fluid prior to or during separation in the mud gas separator.

Appendix A – Mud Gas Separator



Appendix B – Design Consideration of Surface Gas Handling System

Choke and Kill Manifold

Downstream of the chokes, the well bore fluids must be able to be diverted at the buffet tank to either the mud gas separator or relief lines by hard piping. A local pressure and temperature monitoring should be considered in conjunction with the instrumentation arrangement of the mud gas separator and the any well specific requirement. Chemical injection facilities for hydrates inhibitant (e.g. glycol or methanol etc) should be available to address the thermo dynamic effect of the reservoir gas downstream of the chokes.

Mud Gas Separator

The mud gas separators should be able to handle a high proportion of mud solids and may experience hydrate plugging as a result of gas expansion through the choke. Designs based on conventional process practice, involving a float controlled liquid dump valve and a control valve to regulate gas pressure are not suitable because of the accentuated risk of malfunction due to plugging and the consequent need to provide a relief valve which itself may plug. Mud gas separator designs should therefore be based only on a liquid seal system matched to an adequate gas vent.

The operating limits of a mud gas separator should be monitored by observing the differential pressure in the separator. A low range pressure gauge should be installed, readily visible from the choke control position. A remote pressure transmitter may be used for this purpose but should be capable of operation without dependence on rig air supply or rig electrical power. Where remote gauges are installed, a back-up gauge on the separator vessel itself is still recommended.
The separator vessel may be vertical or horizontal with internal baffles and distribution nozzles.

Liquid Throughputs

The volumetric flow capacity of the system should be based on an adequate gravitational rate from the separator. A typical liquid capacity of 6 barrels per minute of 12 pounds per gallons drilling fluid of average viscosity is a guide for vertical mud gas separator.

Liquid seal design

The liquid seal ensures that separated gas vents safely without breaking through to the mud tanks. The seal may be in the form of an external U-tube or may be based on a dip tube extending into a tank, usually the trip tank. The liquid seal hydrostatic pressure must be monitored against the back pressure of the gas vent line in the mud gas separator. It may be integrated as part of an instrumentation control system for the whole system.

Anti-Siphon Line

If the liquid seal is based on a U-tube design, an independent vent pipe, preferably 6 inches nominal diameter or larger, should be fitted at the highest point of the pipe work to avoid siphon effects and as a back-up to dispose of gas carried through the U tube liquid seal. The secondary vent need not extend to the top of the derrick. It should never be tied onto the primary vent.

Relief lines

All surface gas handling systems should have a means of diverting the flow from the choke and kill manifold through overboard relief lines and isolating the mud gas separator. In a blow-out situation, this may be the last resort to allow evacuation of personnel from the drilling rig. The pressure rating of the piping and valves on overboard lines should not be less than the pressure rating of the buffer vessel of the choke and kill manifold. The lines should be as straight as possible with minimum bends to the safe area.

Instrumentation Control System

The mud gas separator should be fitted with temperature and pressure sensors to provide a remote read-out on a panel in the driller's cabin. Local pressure gauge to the separator vessel is optional.

A remote logic control system should be available for the driller to bypass the mud gas separator at the buffet tank when the capacity of the system or liquid seal may be exceeded. Visual and/or audible alarm to alert the driller is optional.

Isolation valves should have pneumatic actuators with air reservoirs to provide power in an emergency situation. The control system should be operated from the driller's cabin, where their location and status are displayed on a mimic board

If the driller decided to activate the bypass operation, the system logic should then isolates the mud gas separator by closing the valves between the vessel and the buffer tank. The valve control system ensures that one flow path is always open.

The driller pre-sets which valve is to be open at any particular time depending on factors such as wind direction and proximity to hazardous operations. The relief lines terminate in locations with lower risk to personnel, i.e. remote away from accommodation, muster area etc.

Appendix C - Mud Gas Separator Design Principles

1) Venting Capacity – The capacity to vent gas

This capacity is the rate at which gas can be vented when the seal is operating at its maximum pressure differential when the liquid seal contains only associated liquids from the hydrocarbon influx. A gradient of 0.69 sg (0.3 psi/ft) should be assumed to determine the maximum pressure differential.

Tank-mounted mud-gas separators using a dip tube seal may rely on a higher seal gradient, providing the tank is continuously circulated with mud at a rate sufficient to dilute any kick liquids.

Operators of separators using U-tube seals may design for higher gradients than 0.69 sg (0.3 psi/ft) only if they arrange for continuous injection of fresh mud into the separator during its operation. If this mode is adopted, the design of the U-tube must take into account the combined volumes of kick fluid and mud circulation.

The capacity to vent is controlled by the height of the liquid seal and the diameter of the gas vent. It is recommended that the seal should be at least 10 feet high but preferably 20 feet. The gas vent should not be less than 8 inches nominal pipe diameter.

The vent capacity will be reduced if an excessively long vent pipe is installed or there are a large number of pipe bends. The venting capacity will also be reduced for a given seal height if the gas density in the vent is high or if oil or mud carry-over into the vent occurs due to incomplete separation.

2) Separating Capacity – The capacity to separate gas cut fluid.

The capacity to separate must not be confused with the capacity to vent. Ideally, the capacity to separate should be greater than the vent capacity, but this may not be possible given the low operating pressure and the constraints of the rig layout. In practice, the capacity to separate may be only 10% of the vent capacity.

The capacity to separate is controlled primarily by the gas velocity in the separator above the inlet section. In vertical separators the area of the separator is the controlling function. Internal baffles will improve the separation process but care must be taken to avoid increasing the risk of plugging with solids/hydrates.

a) Separating Gas Flow Area

The separating gas flow area is largely dependent on the physical arrangement of the separator (horizontal or vertical) and its internal design. The efficiency of the separator is enhanced by its internal baffle layout which increases retention time and therefore gas break-out. This is particularly true for horizontal separators. For a horizontal separator, the fluid level will also influence its capacity to separate gas.

A conservative estimate of this type of horizontal separator's operating factor, F_{co}, of between 0.4 (non-ideal) and 0.5 (ideal) could be applied when calculating the unit's capacity. (F_{co} values can be obtained from the SPE Petroleum Handbook, fig. 12.32 or API spec 12J).

3) Liquid (Droplet Size) Re-entrainment Capacity

Entrainment refers to liquid droplets breaking away from a gas/liquid interface to become suspended in the gas phase. The term re-entrainment is used in horizontal-separator design because it generally is assumed that droplets have settled to the liquid phase and then are returned to the gas phase.

Liquid re-entrainment is caused by high gas velocities. Momentum transfer from the gas to the liquid and associated pressure variations on the gas/liquid interface cause disturbances in the two phase boundary. These disturbances manifest themselves as waves and ripples. Gas-to-liquid momentum transfer to a disturbed interface is more efficient than to a smooth surface, which allows droplets to break away from the liquid phase.

Re-entrainment should be avoided in separator because it is the reverse of the gas/liquid separation desired. This necessity imposes an upper limit on the gas velocity allowed across the liquid surface in the gravity settling section of the separator, which places a lower limit in the vessel on the cross-sectional area for gas flow.

Attachment 1 – Separating Capacity

Example: The separating capacity of the mud gas separator may be evaluated as follows

Relative density of gas = γ (γ = 1 for air)
Minimum design temperature, T = -4°F (-20°C)

Density of gas at standard conditions,

$\rho_{sc} = \gamma_{air}\ \rho_{sc}$
$= 0.0764\ \gamma$ lb/ft^3

Therefore,

Density of gas = $P_g\ \rho_{sc}\ T_{sc}$ / Z $P_{sc}\ T_g$

= 14.7 x 0.0764 γ x 520 / 1 x 14.7 x (460-4)
= 0.087 γ

Entrainment velocity C* (ft/sec)

$C^* = F_{co} \sqrt{}\ (\rho_m - \rho_g) / (\rho_g)$

ρ_m = Density of liquid lb/ft^3
ρ_g = Density of gas lb/ft^3

F_{co} - separator configuration and operating factor (SPE Petroleum Handbook Fig. 12.32).

Gas Separating Capacity (Q_s)

Q_s = AC*
Q_s = mmscf/day

A = Separator Gas Flow Area

Q_s is represented on the chart 7.1 for various values of gas and liquid specific gravities.

Where;
ρ_g = density of gas lb/ft^3
ρ_m = density of liquid lb/ft^3
ρ_g = gas pressure (one atmosphere) 14.7 psia
T_{sc} = temperature at standard conditions
(assume 60°F) 520 ^{0}R
P_{sc} = pressure at standard conditions 14.7 psia
T_g = gas temperature ^{0}R
Z = gas compressibility factor 1 (atmospheric)
A = separating gas flow area ft^2
F_{co} = separator configuration and operating factor
(Reference 4 SPE Petroleum Handbook Fig. 12.32)

Attachment 2 – Venting Capacity

Venting Capacity and Back Pressure (P_b) of Ventline

Pressure drop due to compressible isothermal flow of an ideal gas in a straight pipe (vent line) is calculated using the following iterative relationship:

$24 fL/D = 0.006427 \{(MD^4 P_e^2/TG^2)[(P_i/P_e)^2 - 1]\} - \ln (P_i/P_e)$

Where f = fanning friction factor
L = vent line equivalent length, ft.
T = temperature, ^oR
P_i = pressure in mud gas separator, psia
P_e = pressure at vent exist, psia
M = molecular weight lb.mole
G = mass flow rate lbs/s
D = pipe internal perimeter, ins
The equation assumes that the hydrostatic head due to the gas is negligible. The assumption of isothermal flow is conservative.
The details of the calculation method are given in Attachment
PB is represented on Chart 2

Attachment 3 - Liquid (Droplet Size) Re-entrainment Capacity (Q_L)

The equations used to derive the terminal velocity are shown below (Reference 4). A single equation is only valid over a limited range and therefore three equations are needed in total. The calculation sequence is to derive a value of the Reynolds number, R_{eo} from the Galileo number, G_a and hence the terminal velocity of the droplet can be derived. The dimensions G_a number is used as it is independent of the terminal velocity.

$G_a = d^3 \rho g (\rho_l - \rho) / \mu^2$

$R_{eo} = \rho\, u\, d / \mu$

Where:
d = diameter of the particle
ρ = density of the gas

ρ_l = density of the liquid

g = acceleration due to gravity

μ = viscosity of gas

u = terminal velocity of the particle relative to the gas

And for:

$G_a < 3.6$; $G_a = 18R_{eo}$

$3.6 < G_a <= 10^5$; $G_a = 18\, R_{eo} + 2.7\, (R_{eo}1.678)$

$G_a >= 10^5$; $G_a = (R_{eo})^2 / 3$

By assuming terminal velocity is equal to maximum gas velocity when re-entrainment occurs.

The liquid re-entrainment capacity; Q_L

$Q_L = A_s \times u$

where A_s is the separating gas flow area. in Section xx
Q_L is represented in Chart 3 for various liquid Specific gravity (SG)

Attachment 4 – Liquid Seal Hydrostatic Pressure (P_s)

Length of liquid seal = h feet
Minimum Liquid Seal Hydrostatic Pressure (P_s)

Using fluid pressure gradient 0.3 psi/ft (reference 1)
P, = 0.3 x h psi
The Corresponding density (condensate) = 5.77 ppg (0.69 S.G.)
P_s is represented on Chart 4

Attachment 5 - Gas Flow Rate at Variable Choke Pressure and SCR (P_c)

The gas flow rates are;

Q = Constant x SCR x P x T_{sc} x Z_{sc} / P_{sc} x Z x T

where, Q = Gas Flow Rate in scf/day
Constant = 8085
SCR = slow circulating rate in bbls/min
P = choke pressure in psia
T = choke temperature (520R)
Z = Z -factor at choke pressure and temperature
P_{sc} = pressure at standard conditions (14.7 psia)
T_{sc} = temperature at standard conditions (520°)
Z_{sc} = Z-factor at standard conditions (1)

The Z-factor is calculated by the principle of corresponding states. The critical temperatures and pressures are used for pure dry methane.

Chart 5 shows the gas flow rates at different choke pressures for SCR's of 1, 2 and 4bbls/min. This figure can be used for ANY choke for gas of specific hydrocarbon constituent which are obtained from reservoir data.

Attachment 6 - Ventline Back Pressure and Overboard Relief Line

FOR AN IDEAL GAS

$Cp – Cv = R$

$Cp / (Cp – R)$

or

where Cp = molar specific heat at constant pressure
Cv = molar specific heat at constant volume
R = universal gas constant

γ = ratio Cp / Cv

CRITICAL FLOW RESTRICTION

Sonic velocity is estimated using:

$V_s = \sqrt{49720\ \gamma\ T / M}$

where T = temperature, ^0R
M = molecular weight, lb.mole
V_s = sonic velocity, ft/s

The equation assumes an ideal gas, isentropic (adiabatic), frictionless (reversible) expansion.

The pressure for sonic velocity is calculated as follows:

$P_s = 8.82G/D^2 \sqrt{T/M\ \gamma}$

where T = temperature, OR
M = molecular weight, lb.mole
D = pipe internal diameter, ins
G = mass flow rate, lbs/s
P_s = pressure for sonic flow, psia

The relationship between mass flow rate (lbs/s) and the volume flow rate (ft^3/day) is:

G = Volume Flow Rate (ft^3/day) MW / 1130976MWa

Where; M = molecular weight, lb.mole
G = mass flow rate, lbs/s
MWa = molecular weight of air, lb.mole (28.97)

PIPE FLOW

Pipe segment flow velocity is calculated using:
$v = 1966TG/MPD^2$

where; V = velocity at pressure P, ft. s
P = pipe segment pressure, psia
T = temperature, ^0R
M = molecular weight, lb.mole
G = mass flow rate, lbs/s

D = pipe internal diameter, ins

Pressure drop due to compressible isothermal flow of an ideal gas in a straight pipe (vent line) is calculated using the following iterative equation:

$24\ fL/D = 0.006427\ \{(MD^4\ P_e{}^2/TG^2)[(P_i/P_e)^2 - 1]\} - \ln (P_i/P_e)$

Where; f = fanning friction factor
L = vent line equivalent length, ft.
T = temperature, R
P_i = pressure in mud gas separator, psia
Pe = pressure at vent exist, psia
M = molecular weight, lb.mole
G = mass flow rate, lbs/s
D = pipe internal diameter, ins

Equation assumes that the hydrostatic head due to the gas is negligible. The assumption of isothermal flow is conservative.

The fanning friction factor is calculated explicitly using the equation of Zigrand and Sylvester.

$1/\sqrt{f} = -4 \log \mathit{k/D/3.7} - 5.02 \log A/R_e$

Where;
$A = k/D/3.7 + 13/R_e$
$R_e = 6.31\ W/\mu D$

and k = absolute roughness, ins
R_e = Reynolds number
μ = viscosity, cp
W = mass flow rate, lbs/hr
D = pipe internal diameter, ins

L is the equivalent vent length. This means that extra length of vent line is included to compensate for frictional pressure losses caused by bends in the vent line and for resistance due to pipe entrance and exit.
The extra length which compensates for the bends in the vent lien can be calculated using the following table:

Table A - Representative Equivalent Length in Pipe Diameters *(L/D)* of Various Bends

Type of Bend	Equivalent Length in Pipe Diameters(L/D)
90 Degree Standard Elbow	30
45 Degree Standard Elbow	16
90 Degree Long Radius Elbow	20
90 Degree Street Elbow	50
45 Degree Street Elbow	26
Square Corner Elbow	57

The extra length which compensates for the resistance is calculated as follows:
L = KD / 4f

Where;
K = total resistance
f = fanning friction factor
L = vent line equivalent length, ft
D = pipe internal diameter, ins

To get the total value for K, the separate K values for the exit and entrance are added together.

Table B - K values for different exit and entrance shapes.

Entrance and Exist Shapes	K
Sharp Edged Entrance	0.50
Slightly Rounded Entrance	0.23
Well Rounded Entrance	0.04
Inward Projecting Pipe Entrance	0.78
Sharp Edged Exit	1.00
Rounded Exit	1.00
Projecting Pipe Exit	1.00

Mass Flow Rate and Gas Flow Rate

MFR (lbs/hr) = GFR (scf/d) x MW / 24 / 379

The method used to solve this equation is to assume in the first calculation that the acceleration, In (P/Pe) can be neglected. This gives the following equation:

$$24\ fL/D = 0.006427\ \{(MD^4\ P_e^2/TG^2)[(P_i/P_e)^2 - 1]\} - \ln(P_i/P_e)$$

Where;
f = fanning friction factor
L = vent line equivalent length, ft
T = temperature, ^{0}R
$P_{i(n)}$ = pressure in mud gas separator, psia
Pe = pressure at vent exit, psia
M = molecular weight, lb.mole
G = mass flow rate, lbs/s
D = pipe internal diameter, ins

This formula can be solved directly for the pressure in the mud gas separator and give the first pressure estimate.
$P_i(n)$ = psia
Where; n = 1

The following equation can be solved until $P_i(n) = P_i(n-1)$

Where; n = 2……

$$24\ fL/D = 0.006427\ \{(MD^4\ P_e^2/TG^2)[(P_{i(n)}/P_e)^2 - 1]\} - \ln(P_{i(n-1)}/P_e)$$

L = vent line equivalent length, ft
T = temperature, ^{0}R
$P_i(n)$ = latest estimate of pressure in the mud gas separator, psia
$P_i(n-1)$ = pressure at vent exit, psia
M = molecular weight, lb.mole
G = mass flow rate, lbs/s
D = pipe internal diameter, ins

Nomenclature

Cp = molar specific heat at constant pressure
Cv = molar specific heat at constant volume
D = pipe internal diameter, ins
f = fanning friction factor
G = mass flowrate, lbs/s
k = absolute roughness, ins
K = total resistance
L = vent line equivalent length, *it*
MW = molecular weight, lb.mole
MWa = molecular weight of air, lb.mole (28.97)
P = pipe segment in mud gas separator
P_i = pressure in mud gas separator
P_o = pressure at vent exit, psia
P_s = pressure for sonic flow, psia
R = universal gas constant
R_e = Reynolds number
T = temperature, ^{0}R
V = velocity at pressure P, ft/s
V_s = sonic velocity, ft/s
W = mass flow rate, lbs/hr
MFR = Mass Flow Rate, lbs/hr
q = Gas Flow Rate, mmscft/day

Attachment 7 - Gas Handling System Analysis Data Sheet

1. System Design Parameters

a) Reservoir depth
b) Reservoir pressure
c) Reservoir temperature
d) Reservoir gas bubble point pressure
e) Circulation rate (min/max) of drilling mud (kill rate)
f) Density of drilling mud
g) Typical size of gas influx of reservoir condition
h) Estimated gas temperature at wellhead condition
i) Max. size of liquid particles in vented gas
j) Length of vent pipe
k) Viscosity of gas at STP

2. Reservoir Gas Properties

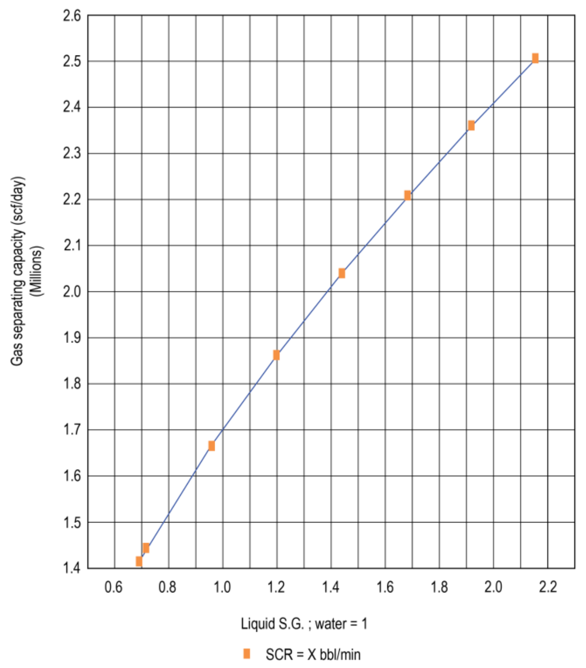
a) Molecular weight
b) Gas viscosity
c) Gas density at Reservoir conditions
d) C_p/C_v ratio
e) Critical constants
(i) Critical pressure P_c
(ii) Critical temperature T_c
(iii) Critical volume V_c
(iv) Gas Compressibility Factor Z_c
(v) GOR

3. Drilling Fluid Properties

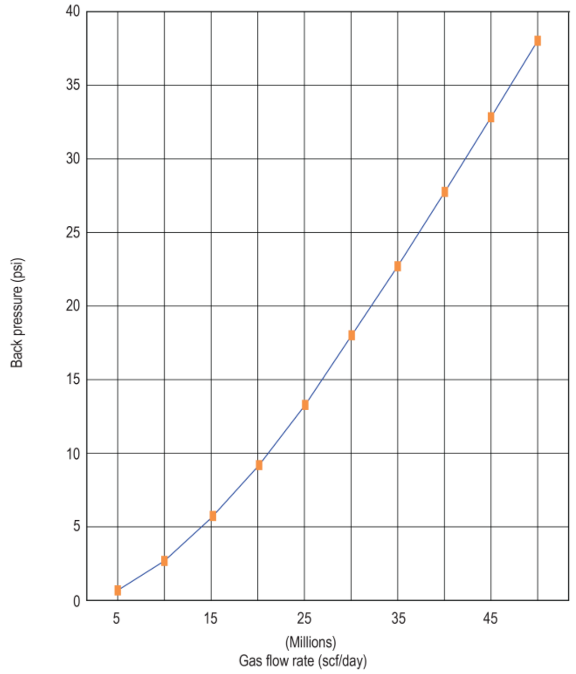
a) Density of drilling mud
b) Plastic viscosity
c) Yield point (Bingham plastic)

Attachment 8 – System Performance and Well Control Chart

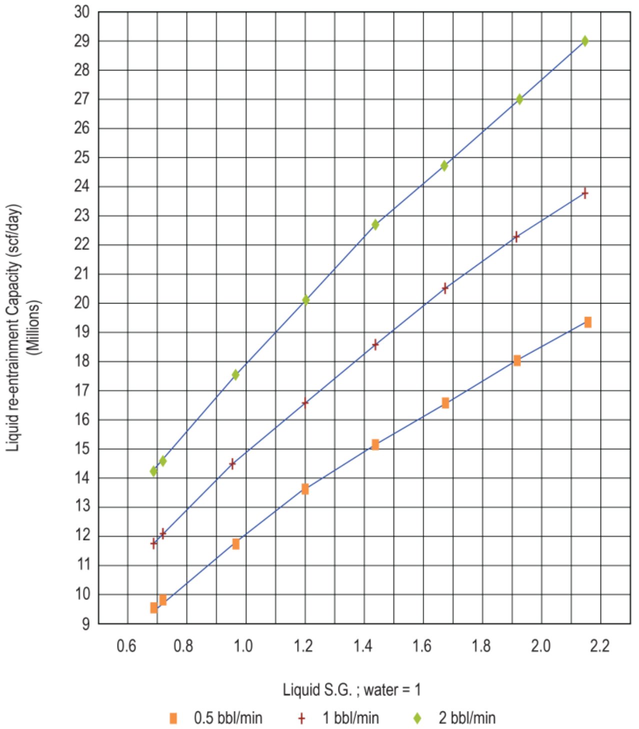
Graph 1 – Gas Separating Capacity Capacity



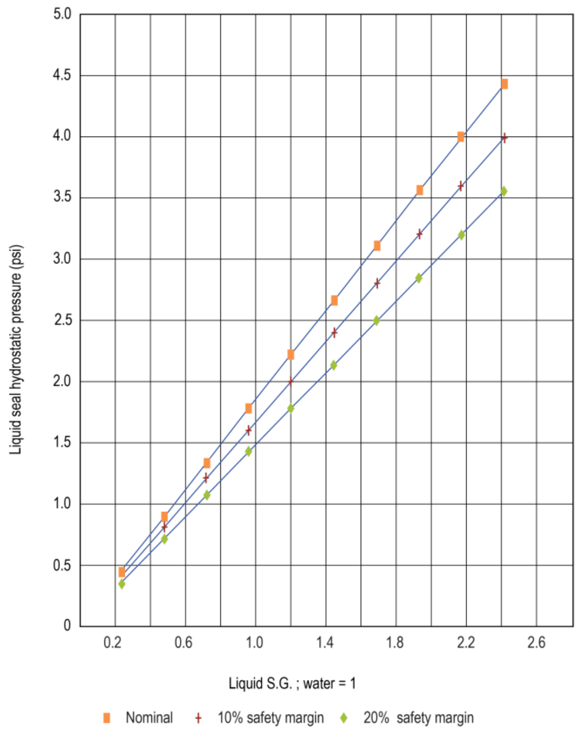
Graph 2 – Gas Venting



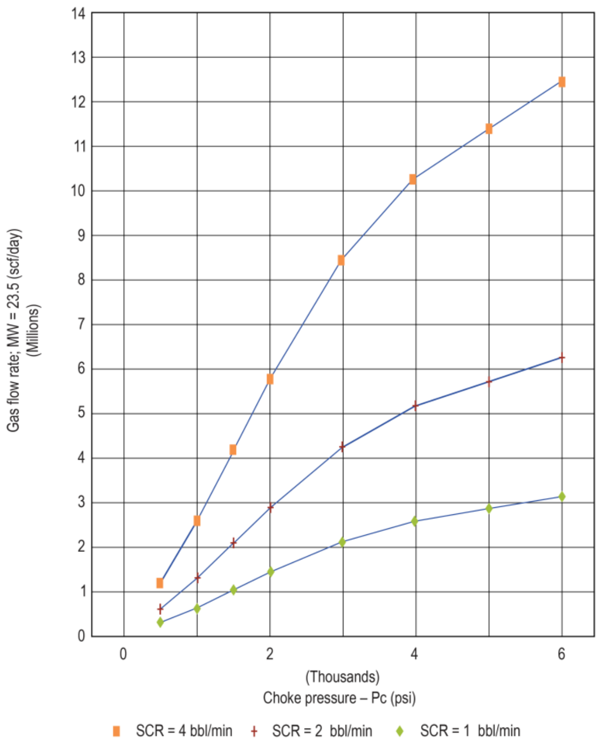
Graph 3 – Liquid re-entrainment Capacity pressure



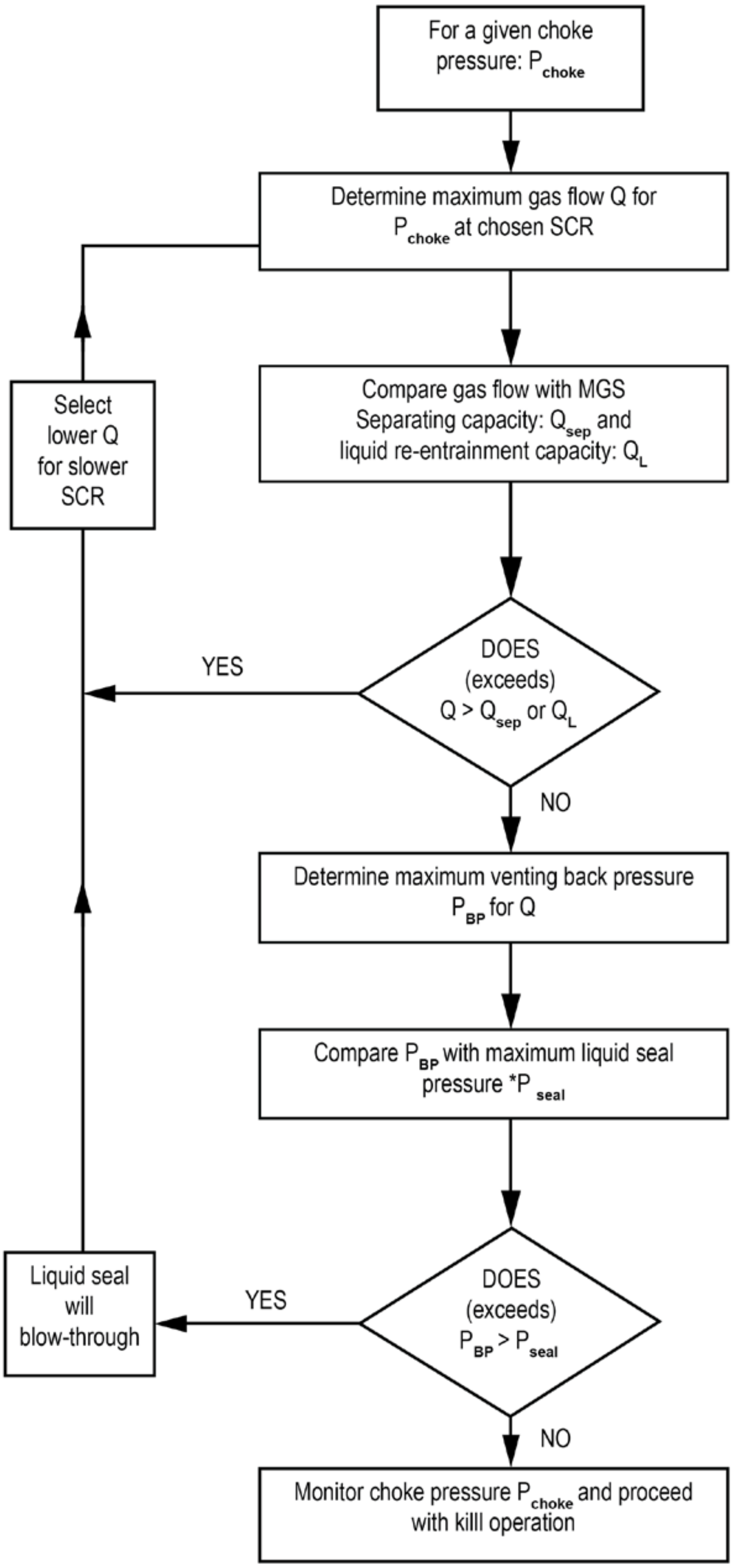
Graph 4 – Liquid Seal



Graph 5 – SCR Vs Choke Pressure



Graph 6 – Well Control Decision Tree



Further information

Further information can be obtained from Petroleum Engineering Discipline, Department of Natural Resources, Petroleum and Gas Inspectorate.

References

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