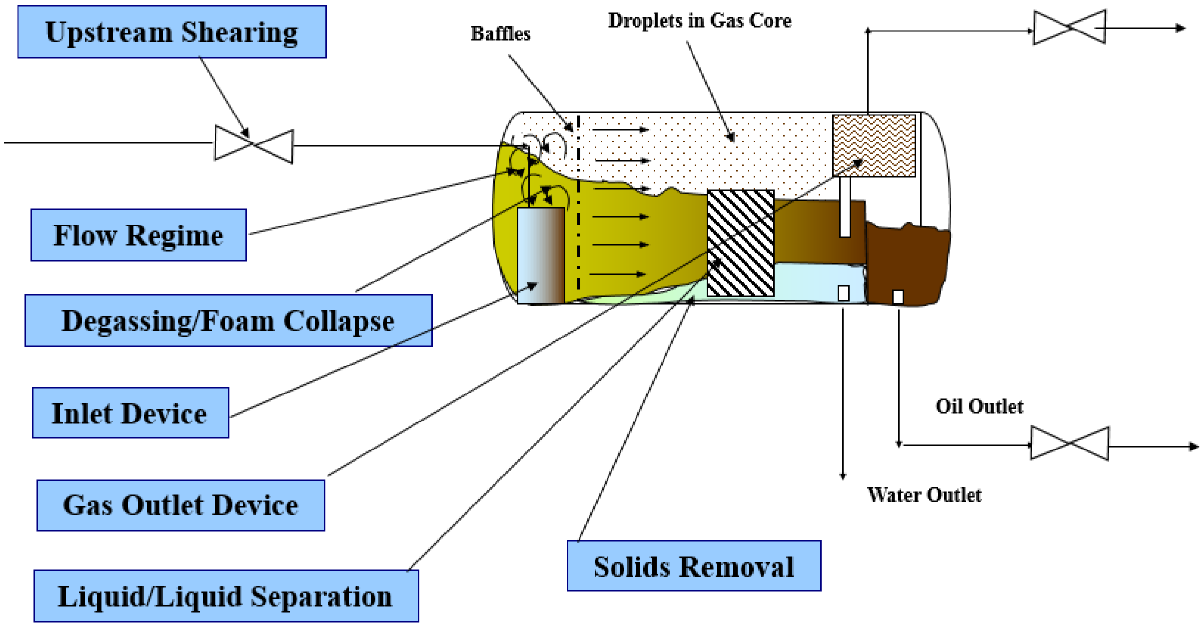
Oil, Gas and Water Separation



1 Introduction

Separation is at the centre of Upstream processing. The purpose of the separation system in achieving transport specifications is discussed. This module reviews the theory of gravity separation and the complexities introduced by colloid (emulsion) chemistry. Key design variables such as residence time, heating, cooling and number of stages are discussed together with chemical treatment. Vessel internals are also reviewed and typical P&IDs presented.

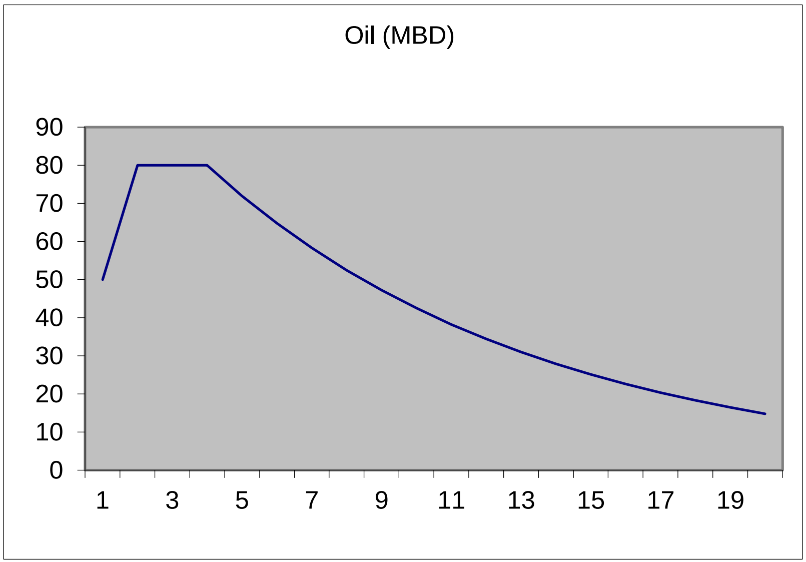
2 Life of Field Design

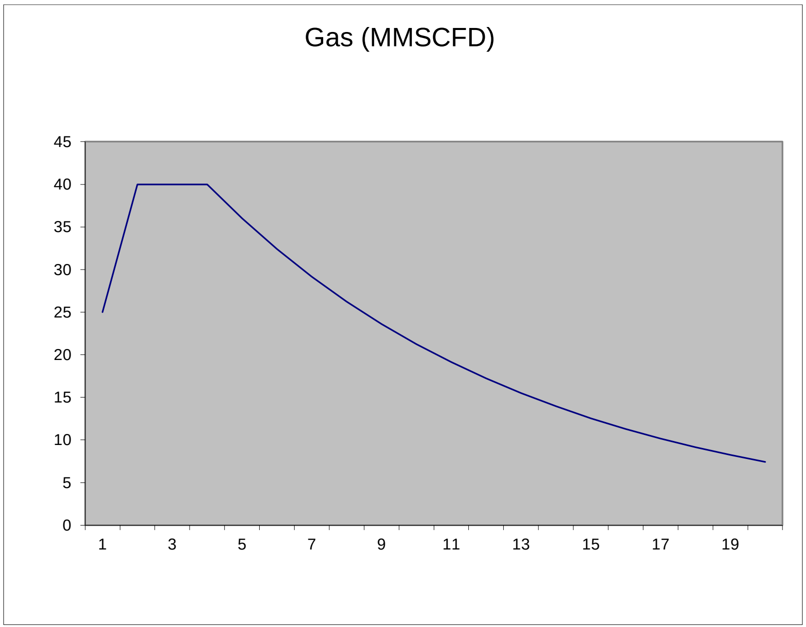
The key processing characteristics during the development of an oilfield can be difficult to predict. Unlike an onshore chemical plant where the feedstock tends to be fixed and of a known quality, there will be a range of conditions which the oilfield equipment will have to be designed to process during its lifetime.

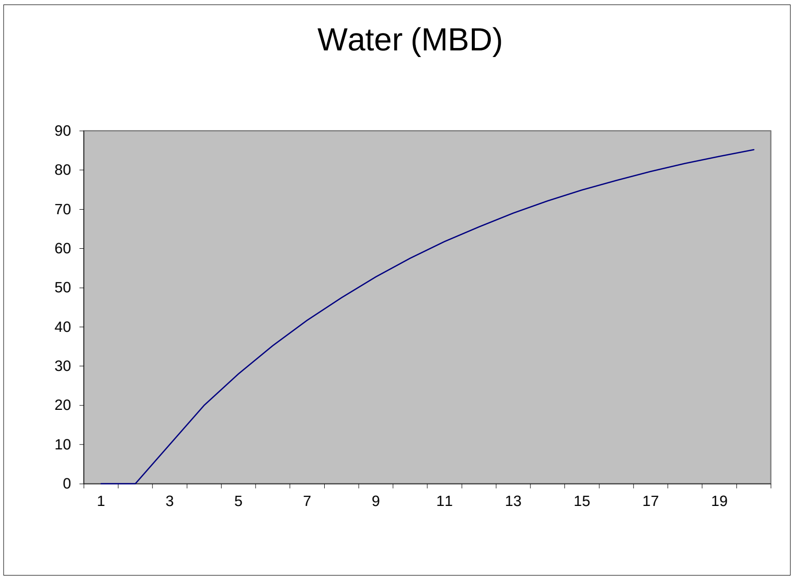
Other aspects which may affect the design are;

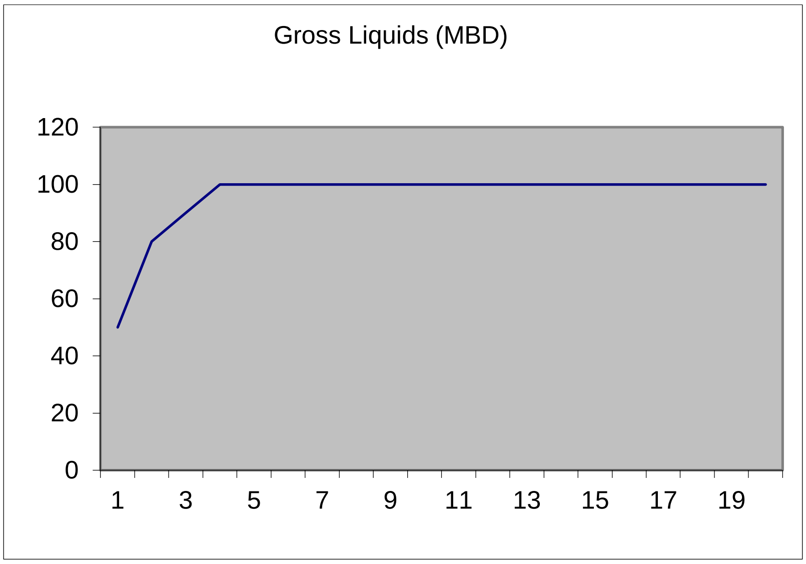
- Changing Composition
- Sand
- Water Chemistry
- Wax
- Asphaltenes

For an oilfield typical annual profiles would be as follows – x axis is production years;









It is important to recognise the conditions which will most test the system design. For example, it may not be peak oil which dominates the design, it could be a particular oil to water ratio where difficult to separate emulsions are formed.

3 Oil Product Specifications

Like all chemical processing systems the design is driven by the feedstock and the product specification. Together with the key aspects of Safety, Environment, Operability and Profitability, these two boundaries shape the equipment configuration and design.

Crude oil is usually exported to market by tanker or by pipeline, with road and rail shipments used for smaller volumes. For the safe handling of crude, the vapour pressure and maximum delivery temperature are specified.

3.1 True Vapour Pressure

True vapour pressure of an oil and hydrocarbon liquid is a key specification. The reference temperature for the vapour pressure is normally 100 ^oF, 37.8 ^oC . For storage the True Vapour Pressure (TVP) must be less than 1 bara to prevent vapour loss in transit and also to ensure no vapour break out which could affect the safety of the system.

If a pipeline is the export route, the TVP is set in conjunction with the operating parameters of the pipeline and associated shore terminal.

The TVP of the export oil is controlled by the exporting plant operating conditions: pressure and temperature of the final stage of separation. At the final point where the composition is altered.

3.2 Reid Vapour Pressure

TVP cannot easily be measured, so instead an experimental method measures the Reid Vapour Pressure (RVP). The TVP is then determined using a correction factor. RVP is determined experimentally – an oil sample is placed in a standard cell with 20% oil and 80% v/v air. The RVP is the pressure of the vapour in the cell at 100 ºF. A Typical RVP spec is 0.7 bara (10 psia) at 38 ºC.

3.3 Water and Salt Content

Water and salt content of the also need to meet specified values as set by downstream processing requirements. These are generally fixed by the sales requirement, typical pipeline values are;

Water content: 2-5 vol %

Salt content: 70 - 200 mg per litre

Higher water contents reduce the pipeline or storage capacity and crude sales value – buyers do not want water. Furthermore water can also lead to pipeline corrosion. For tanker transport a more stringent water specification is often specified: BS&W (Basic Sediment and Water) Content: 0.5 vol% maximum

3.4 Pour Point and Viscosity

Pour point (wax gelling characteristic) and viscosity may be specified to prevent pipeline and storage problems.

3.5 Corrosive Constituents

Corrosive products limitations are often imposed to protect pipelines e.g. H_2S and CO_2 .

3.6 Chemical Additives

Chemical additives (methanol, corrosion inhibitors) will also be controlled to certain specifications.

A typical Oil pipeline specification follows.

Carbon Dioxide	Maximum of 0.2 mole % of carbon dioxide in Shippers Pipeline Liquids.
Nitrogen	Maximum of 0.2 mole % of nitrogen in Shippers Pipeline Liquids
Carbonyl Sulphide	Maximum of 0.02 ppm by weight in Shippers Pipeline Liquids.
Hydrogen Sulphide	Maximum of 0.1 ppm by weight as sulphur in Shippers Pipeline Liquids
Mercaptans	Maximum of 0.1 ppm by weight as sulphur of volatile mercaptons in Shippers Pipeline Liquids, which separate into Raw Gas under Kinneil operating conditions.
Mercury	Maximum of 0.35 ng/g as volatile organic or inorganic mercury in Shippers Pipeline Liquids, which separate into Raw Gas under Kinneil operating conditions.
Sediment and Water	Maximum of 2% by volume provided that Shippers' Pipeline Liquids are essentially free of sediment. Produced water shall be made compatible (at the cost of the Shippers' Owners) with water produced by other Forties System Users.
True Vapour Pressure	Maximum of 125 psig at 60oF, as measured in the Shippers Pipeline Liquids.
Viscosity	Maximum of 15 centiStokes at 4oC in the Shippers Pipeline Liquids

Acidity	The total acid number shall be no greater than 0.30 mg of potassium hydroxide per gram of Stabilised Crude Oil derived from Shippers Pipeline Liquids.
Emulsions	Shippers' Pipeline Liquids and those of Other Users when mixed should not form emulsions which are stable at temperatures at or above 36^{o}C and pressures at or above one bar absolute.
Metals	Vanadium plus nickel shall not exceed 5 ppm by weight in Shippers Pipeline Liquids.
Salt Content	Maximum of 1500 milligrams per litre of sodium, calcium and magnesium chlorides in solution in Shippers Pipeline Liquids.
Entry Pressure	Minimum of 125 barg at delivery in the Forties System at either Unity or Forties Charlie.
Oxygenates	Shippers Pipeline Liquids shall not contain oxygenates.
Alcohols	Shippers Pipeline Liquids shall not contain alcohols.
General	No chemical additives or processing material shall be injected into Shippers' Pipeline Liquids either directly or through processing without prior consultation and agreement. All chemical additives must comply with the Offshore Chemical Notification Scheme (OCNS) [Department of Trade and Industry] and no endocrine disrupter are permitted. Shippers' Pipeline Liquids to be free of undesirable matter (including, without limitation, radioactive materials).

Note the TVP in the case is much higher than 1 bara. In this instance the pipeline can handle a higher TVP than a storage tank. The pipeline delivers the oil to a shore a terminal which will 'stabilise' the oil for tanker transportation.

4 Separation

As an oil field is developed it is not unusual for significant quantities of water to be produced. Initially the water quantities maybe small but as a result of how the oilfield is managed, the quantities of water often steadily rise. Indeed it is not unusual for an ageing field to be producing water to oil ratios of 90% or more.

Water is an undesirable component when trading oil and as previously mentioned it has to be removed. The export route for the oil will dictate the required residual level of water - 0.5% to 2% water being typical values for oil tankers and oil pipelines respectively.

A further important export specification is the vapour pressure of the product crude. This is particularly important for oil tankers and refinery storage tanks where the evolution of vapours could pose safety issues.

Sand production can be very problematic – this is dependent upon the reservoir and the success of downhole sand removal screens. Should sand production be experienced the effects on the efficiency of separation can be significant. Sand results in erosion, blockages and reduction in residence time for separation. Other issues such as wax, scale and foaming require to be considered.

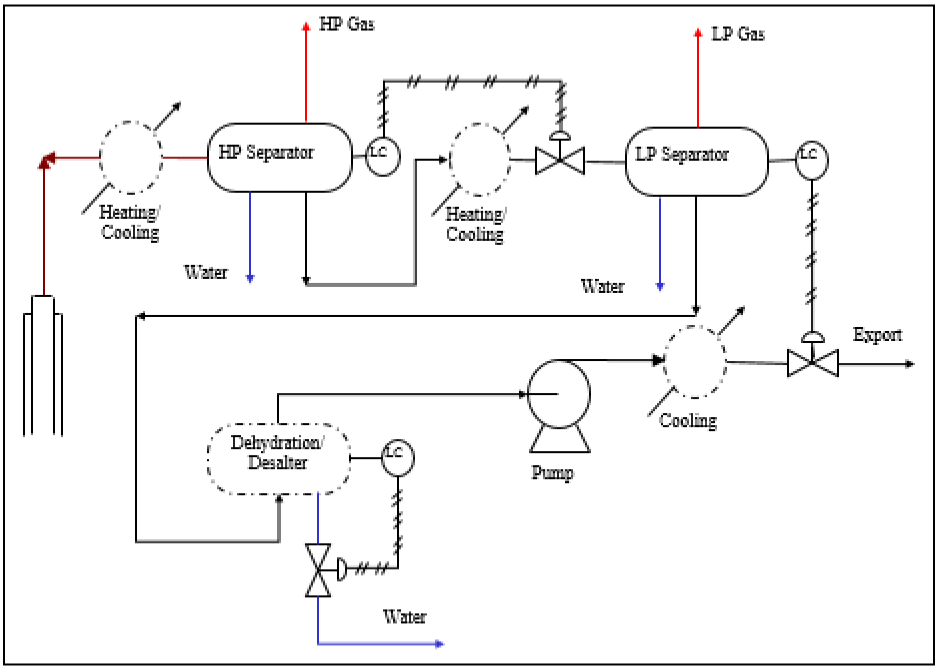
A range of vessel types are used to separate the gas, oil, water and sand using their differing densities. Sufficient residence time has to be given to allow the water droplets to settle from the oil and vice versa. Multiple stages are used to liberate gas and remove water. The pressure is reduced in stages delivering gas to compression or gas treatment at differing pressures. The final stage pressure and temperature is used to control crude vapour pressure. The number of stages is assessed balancing cost, energy efficiency, effect on the reservoir and safety.

The separation process may require heating to help destabilise oil-water emulsions. Conversely, for high temperature fields the fluids may be cooled to prevent the loss of valuable liquid products e.g. propane and butane into the flashed gas.

Chemicals are utilised to assist droplet coalescence, break foams and prevent corrosion.

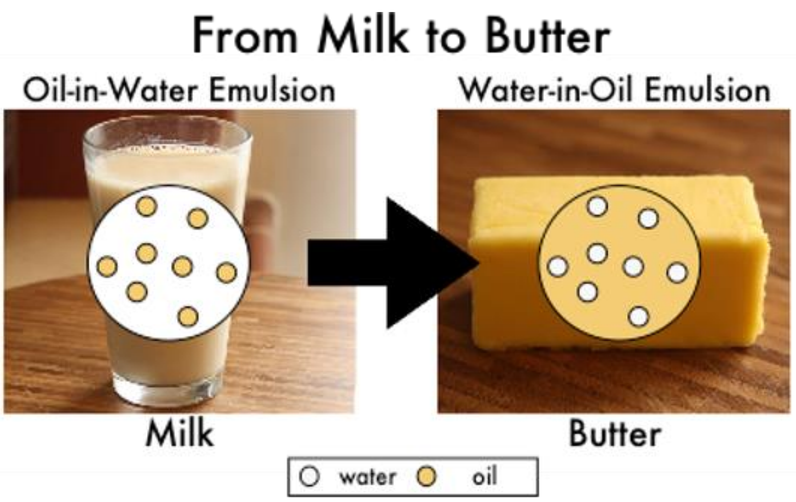
To prevent remixing and effective separation the separator is fitted with a range of internal devices.

A typical scheme showing two stages of three phase, gravity separation, with the application of possible heating or cooling. The requirement for a dehydration and or desalting stage is also indicated.



4.1 Emulsions

An emulsion is a stable mixture of two or more liquids in which one is present as droplets distributed throughout the other. Emulsions are formed from the component liquids either spontaneously or, more often, by mechanical means, such as pipe shearing. Emulsions are stabilized by agents that form films at the surface of the droplets or that impart to them a mechanical stability (e.g. fine solids). Some familiar emulsions are milk (a dispersion of fat droplets in an aqueous solution) and butter (a dispersion of droplets of an aqueous solution in fat).



A stable emulsion needs four conditions:

– Two immiscible liquids (oil/water)

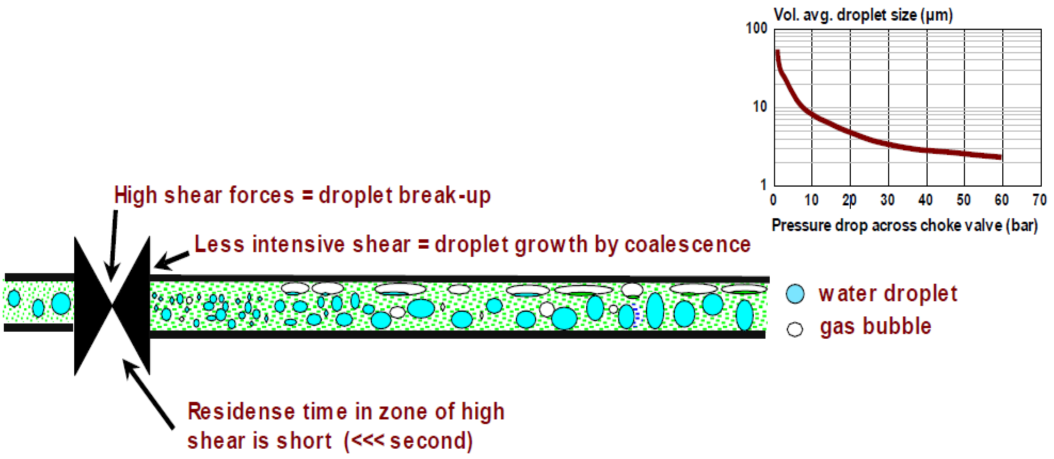
– Emulsion stabilising agent - asphaltene, resins, organic acids, production chemicals, solids

– Energy input to the system (shear, agitation, pressure drop)

– Time, for the stabilising agents to accumulate at the interfaces

The emulsion stability is affected by the amount of shear it has experienced. Shear is introduced from/by;

– wellbore vicinity
– wellbore
– gas lift valves
– pumps
– chokes
– bends
– manifolds
– inlet nozzles



Emulsions characteristics are dependent upon;

Droplet diameter – larger droplets produce less stable emulsions.

Water to oil ratio – reducing the volume of the dispersed phase means droplet coalescence is less likely to occur.

Interfacial film – even if droplets collide the may not coalesce due to the strength of the interfacial film.

Viscosity – if the continuous phase has a high viscosity the frequency of droplet collision will be reduced. Increased velocity also hinders droplet settling or rising velocities.

Temperature – increasing temperature reduces viscosity which improves droplet collision frequency and increases settling or rising velocities. It also weakens interfacial film strength hence promoting droplet coalescence.

Salinity – fresh water favours more stable emulsions.

Emulsions can also have a "history", which effectively means that the older the emulsion is the more stable it becomes; this phenomenon is known as ageing. The thermal history will also affect the emulsion characteristics.

4.1.1 Emulsion Inversion

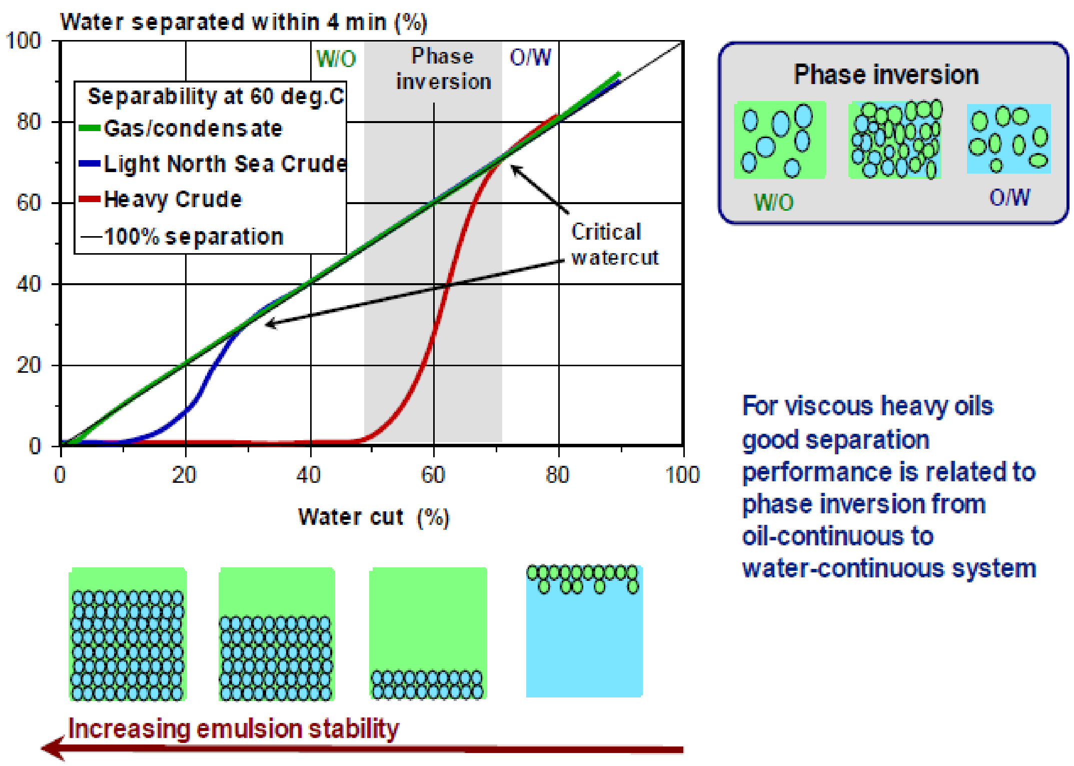
Emulsion inversion point, typically:

- below 30-60% watercut: oil is the continuous phase
- above 30-60% watercut: water is the continuous phase

A continuous water phase has the more favourable transport properties as water has a low viscosity. The fine dispersion of water within an oil can result in viscosities which are several orders of magnitude greater than the individual phases. High viscosities can seriously hinder the separation process.

An oil in water emulsion will settle more quickly than a water in oil emulsion, therefore production separators may operate better at higher water regimes (oil in water emulsions)

In the following figure the separation of oil and water after 4 minutes is presented. This shows that, as expected, a heavy, higher density viscous crude is much harder to separate from water than a light gas condensate.



4.1.2 Emulsion Heating

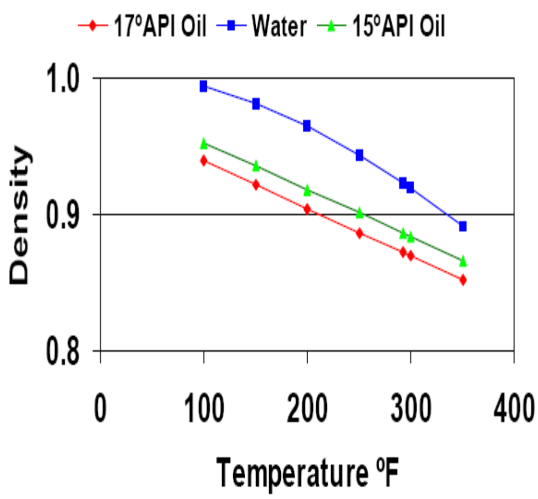
Using heat to assist the resolution of emulsions is commonly used it has four impacts;

– Heat reduces the viscosity of the oil which promotes the collision of more water droplets. Larger water droplets settle more readily.

– Heat increases molecular movement promoting droplet collision and coalescence.

– Heat may help destabilise some of the emulsion stabilising components and also assist the action of any added chemical demulsifiers.

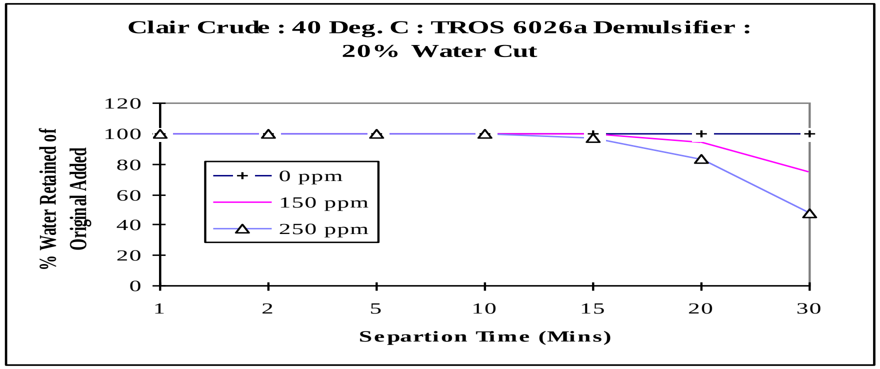
– Heat may also increase the density difference between the two phases. This is not always the case as illustrated opposite where a clear optimum temperature would exist. The benefit obtained by reducing viscosity is offset by a poorer density difference.

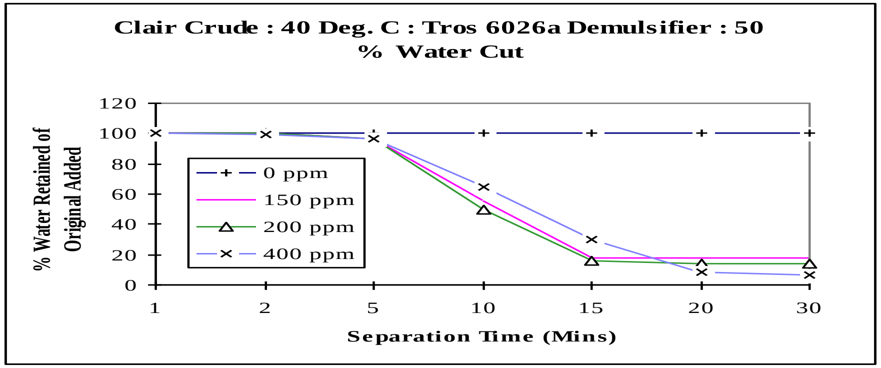


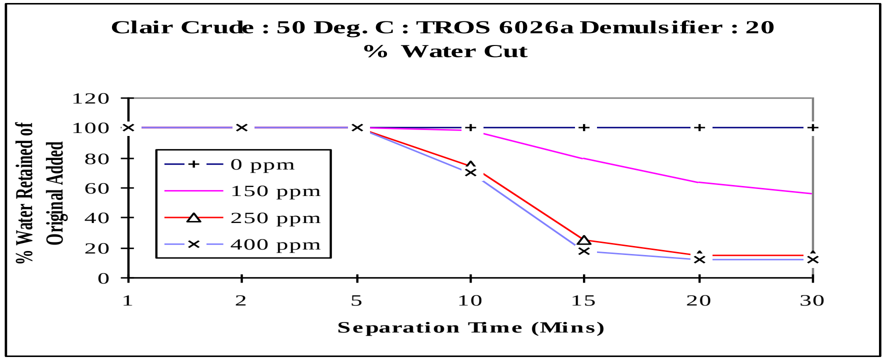
4.1.3 Bottle Tests

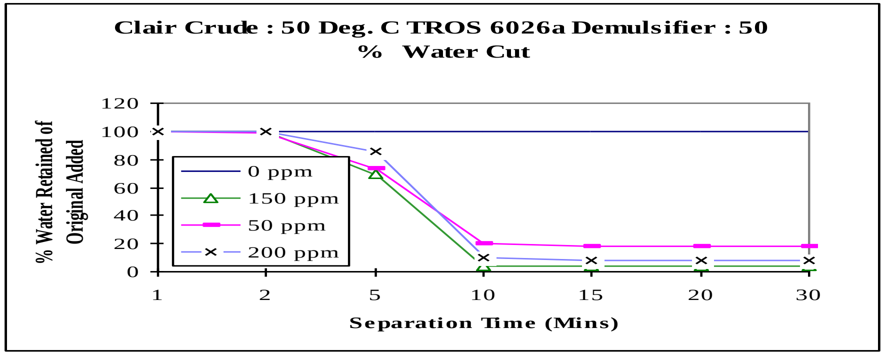
Emulsion behaviour is difficult to predict as a consequence of the complexity of the surface chemistry. To help understand oil/water emulsion characteristics bottle tests are frequently carried out. Laboratory experiments are conducted on a range of oil water mixtures at various temperatures and demulsifier types and concentrations. These test give very useful information on residence time, temperature and demulsifier effectiveness.

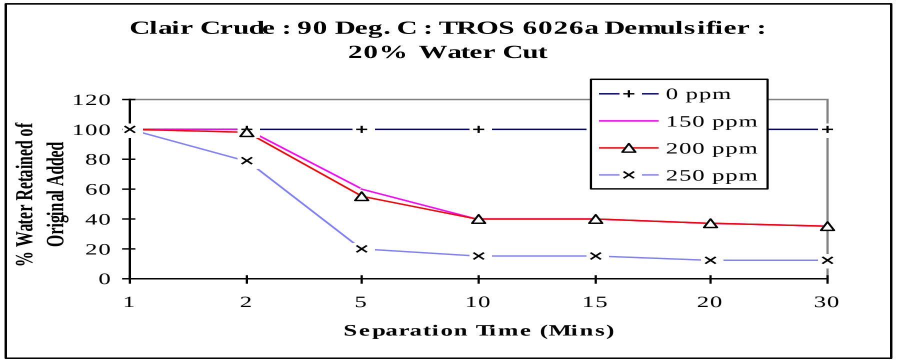
Bottle tests would provide information as follows.

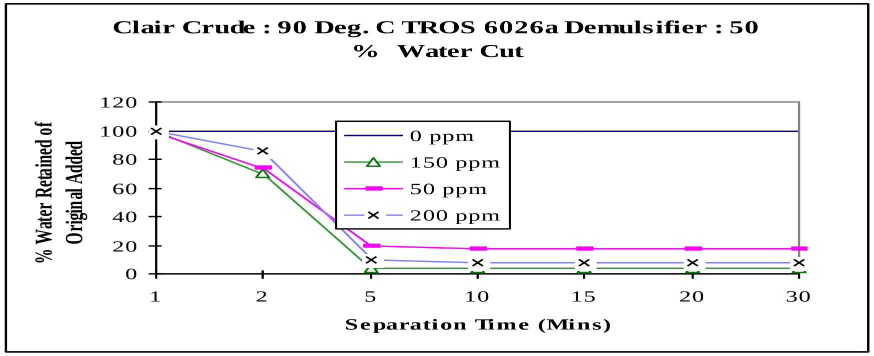

Clair Crude : 40 Deg. C : TROS 6026a Demulsifier : 20% Water Cut
% Water Retained of Original Added
Separtion Time (Mins)
0 ppm
150 ppm
250 ppm


Clair Crude : 40 Deg. C : Tros 6026a Demulsifier : 50 % Water Cut
% Water Retained of Original Added
Separation Time (Mins)
0 ppm
150 ppm
200 ppm
400 ppm


Clair Crude : 50 Deg. C : TROS 6026a Demulsifier : 20 % Water Cut
% Water Retained of Original Added
Separation Time (Mins)
0 ppm
150 ppm
250 ppm
400 ppm


Clair Crude : 50 Deg. C TROS 6026a Demulsifier : 50 % Water Cut
% Water Retained of Original Added
Separation Time (Mins)
0 ppm
150 ppm
50 ppm
200 ppm


Clair Crude : 90 Deg. C : TROS 6026a Demulsifier : 20% Water Cut
% Water Retained of Original Added
Separation Time (Mins)
0 ppm
150 ppm
200 ppm
250 ppm

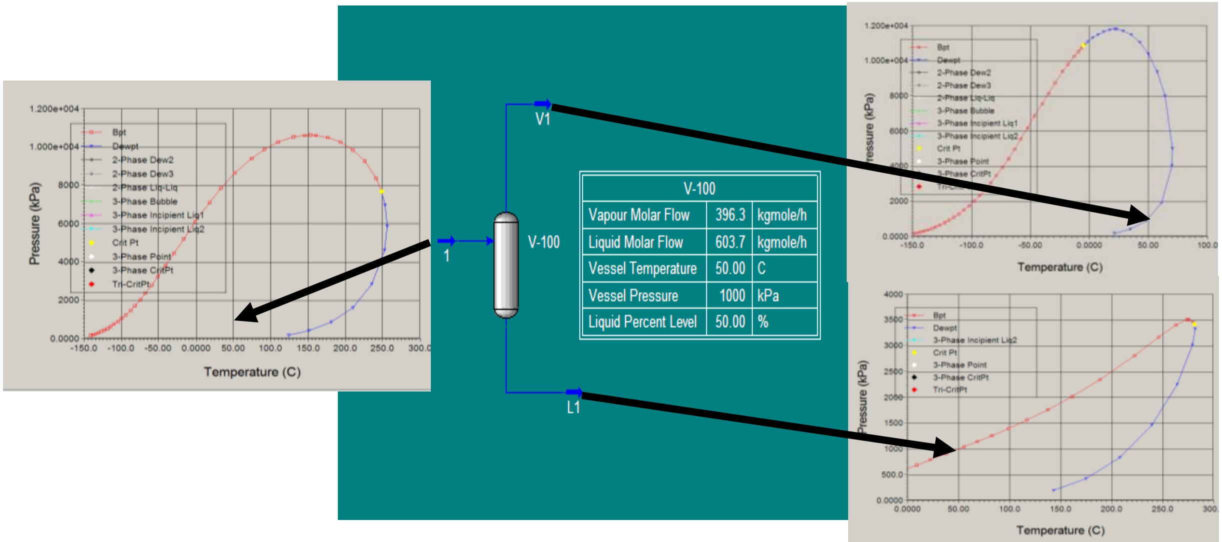

Clair Crude : 90 Deg. C TROS 6026a Demulsifier : 50 % Water Cut
% Water Retained of Original Added
Separation Time (Mins)
0 ppm
150 ppm
50 ppm
200 ppm

These test confirm;

– Water separation improves with increasing temperature
– Demulsifier addition is essential for separation
– At higher water cuts separation improves
– After a certain residence time no additional separation benefit is achieved.

5 Separation System Heat and Mass Balance

The heat and mass balance for a separation system will usually be prepared heat and mass balance simulators such as HYSYS or UNISIM. By their nature the simulators assume thermodynamic equilibrium to partition the various compound between the phases.
Water being a polar molecule needs special attention and the separation of oil from water cannot be predicted by such simulators. As prerviously stated the colloid chemistry is not predictable and requires other methods, such as bottle tests, to establish the characteristics of oil water separation.
The following illustrates the location of the feed, vapour and liquid streams with respective to the corresponding phase envelopes.



Note the following;

– Feed stream 1 is multi-phase.
– The vapour outlet V1 is on its dewpoint – further cooling of this stream will result in liquid condensation.

– The liquid product L1 is at its bubble point – any reduction in pressure will result in vapour boil-off.

– If water is present, the gas stream will be saturated with water at the prevailing separator conditions.

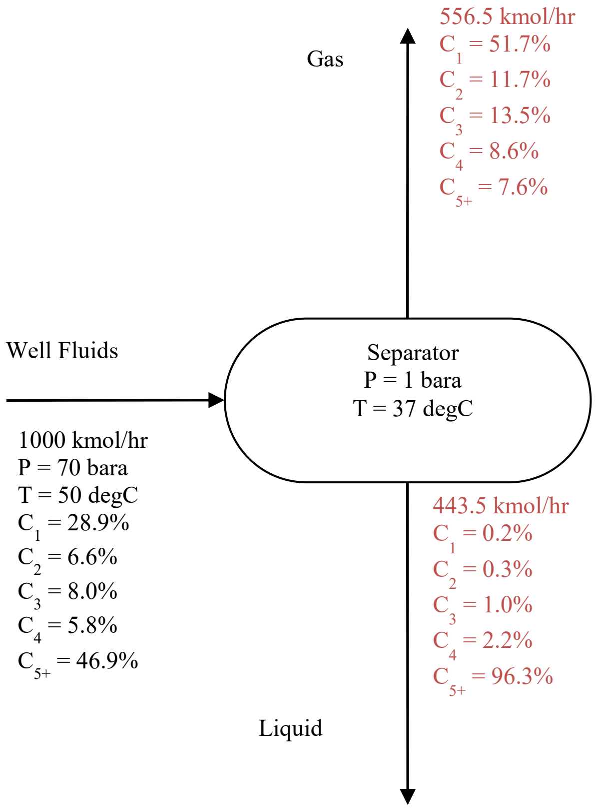
5.1 Separation Stage Sensitivity

A one and three stage hydrocarbon separation process is illustrated in the following simple heat and mass balances.

– The feed stream is a mixture of methane, ethane, propane and butane.

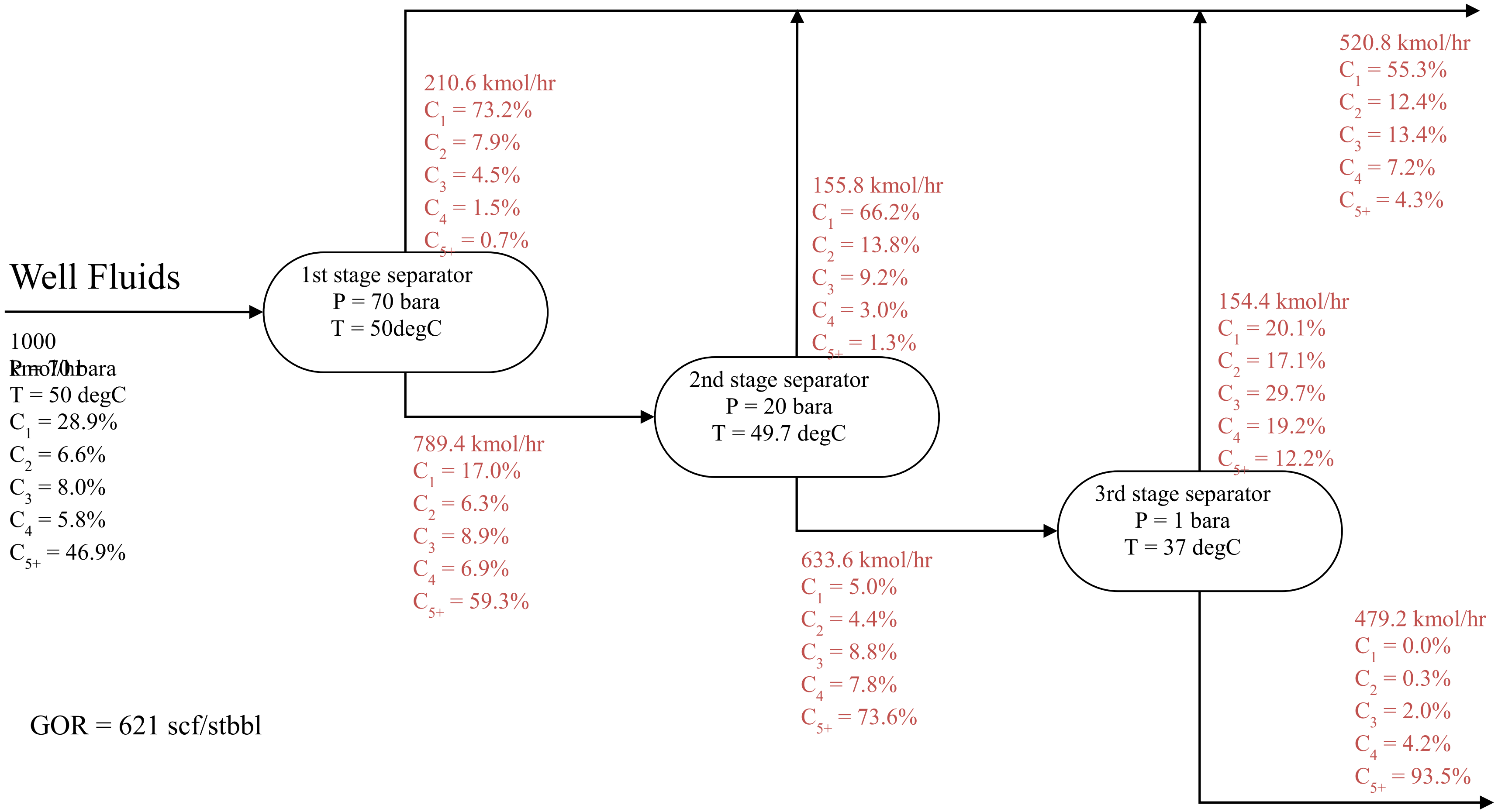
– A C5plus fraction (hypothetical/pseudo component) represents the heavy end constituents of the oil.

– The vapour pressure (TVP) is dictated by the separator pressure and temperature. In all cases the product TVP is the same.

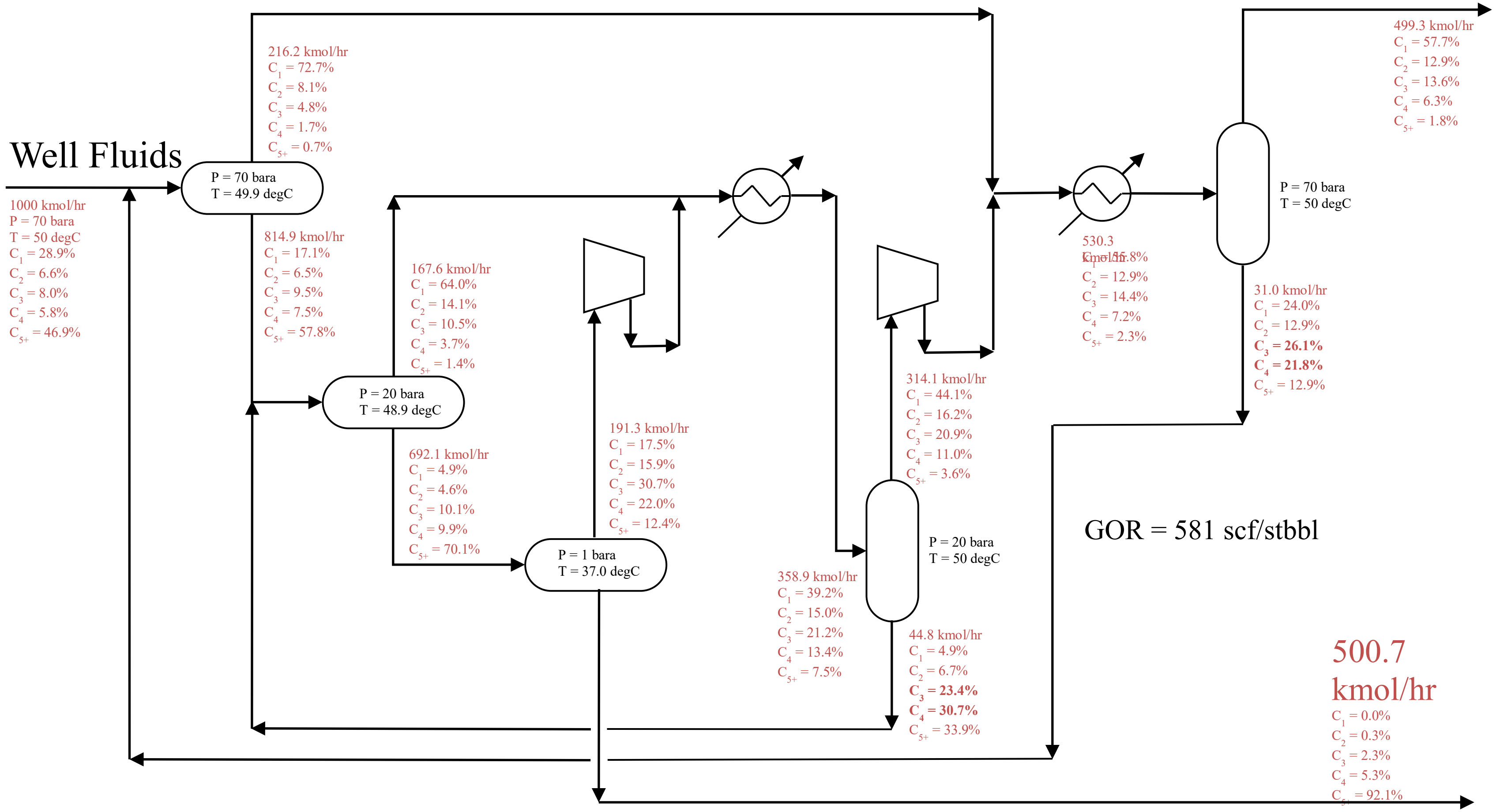


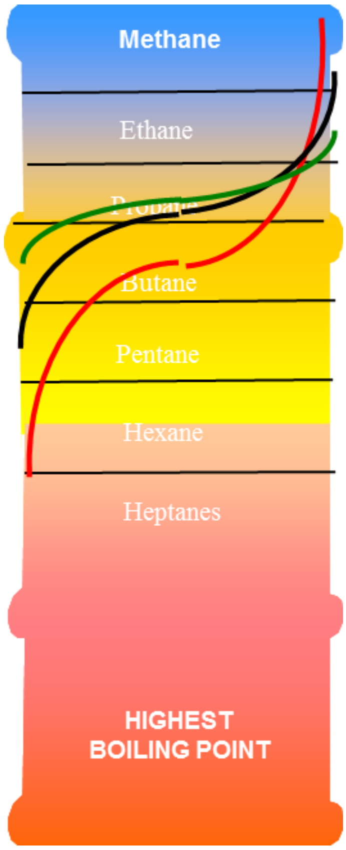
GOR = 689 scf/stbbl
Gas Oil ratio – volume units of gas per volume units of oil

TVP of product is 1 bara



GOR = 621 scf/stbbl


Well Fluids
1000 kmol/hr
P = 70 bara
T = 50 degC
C1 = 28.9%
C2 = 6.6%
C3 = 8.0%
C4 = 5.8%
C5+ = 46.9%
P = 70 bara
T = 49.9 degC
216.2 kmol/hr
C1 = 72.7%
C2 = 8.1%
C3 = 4.8%
C4 = 1.7%
C5+ = 0.7%
814.9 kmol/hr
C1 = 17.1%
C2 = 6.5%
C3 = 9.5%
C4 = 7.5%
C5+ = 57.8%
P = 20 bara
T = 48.9 degC
167.6 kmol/hr
C1 = 64.0%
C2 = 14.1%
C3 = 10.5%
C4 = 3.7%
C5+ = 1.4%
692.1 kmol/hr
C1 = 4.9%
C2 = 4.6%
C3 = 10.1%
C4 = 9.9%
C5+ = 70.1%
P = 1 bara
T = 37.0 degC
191.3 kmol/hr
C1 = 17.5%
C2 = 15.9%
C3 = 30.7%
C4 = 22.0%
C5+ = 12.4%
358.9 kmol/hr
C1 = 39.2%
C2 = 15.0%
C3 = 21.2%
C4 = 13.4%
C5+ = 7.5%
314.1 kmol/hr
C1 = 44.1%
C2 = 16.2%
C3 = 20.9%
C4 = 11.0%
C5+ = 3.6%
P = 20 bara
T = 50 degC
44.8 kmol/hr
C1 = 4.9%
C2 = 6.7%
C3 = 23.4%
C4 = 30.7%
C5+ = 33.9%
530.3
kmol/hr
C1 = 55.8%
C2 = 12.9%
C3 = 14.4%
C4 = 7.2%
C5+ = 2.3%
P = 70 bara
T = 50 degC
499.3 kmol/hr
C1 = 57.7%
C2 = 12.9%
C3 = 13.6%
C4 = 6.3%
C5+ = 1.8%
31.0 kmol/hr
C1 = 24.0%
C2 = 12.9%
C3 = 26.1%
C4 = 21.8%
C5+ = 12.9%
GOR = 581 scf/stbbl
500.7
kmol/hr
C1 = 0.0%
C2 = 0.3%
C3 = 2.3%
C4 = 5.3%
C5+ = 92.1%



The findings are sumarised;

Single Stage Separation - red:
Effectively the highest GOR
Lowest methane content in the gas

Multi Stage Separation - black:
Lower effective GOR
Higher methane content in the gas
High methane content in the gas from the first separation stage

Multi Stage Separation with NGL Recovery (Gas Compression) -green:
Lowest effective GOR
Highest methane content in the gas
High content of NGL's (propane, butane) in the liquid

A rule of thumb for assessing the number of stages is shown opposite. FWHP is the flowing wellhead pressure – the pressure the reservoir delivers fluid to the facility.

FWHP Bara	No. Separation Stages
0 - 20	1 or 2
20 - 70	2 or 3
Over 70	3 or 4

Typical final stage pressures for pipeline and tanker conditioned crudes are shown. As can be seen the tanker TVP specification is less than atmospheric pressure. This ensures that no gas will evolve from the oil when it is transferred to storage whereas the pipeline can handle a higher vapour pressure.

Export Method	TVP Specification (bara)	Final Stage Operating Pressure (bara)
Tanker	0.965 at 25 degC	1.4 - 2.0
Pipeline	6.9 at 38 degC	7.0

6 Gravity Separation

Common oilfield terminology is presented below.

Free Water Knock Out Drum: Free water knock out (FWKO) is a term used to describe the gravity separation of water which is not emulsified with the oil. FWKO vessels are usually the first separation vessel in the separation train. Bulk water is removed at this stage. This reduces the forward flowing mass flow and hence the heating duties of downstream heaters.

Flash Tank: A vessel used to separate the gas evolved from liquid flashed from a higher pressure to a lower pressure.

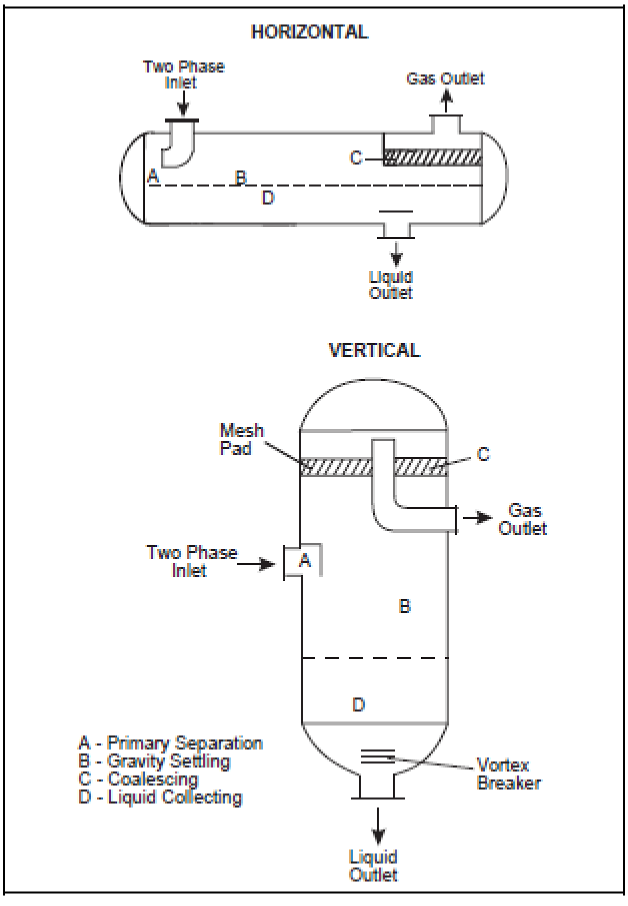
Liquid-Liquid Separators: Two immiscible liquid phases can be separated using the same principles as for gas and liquid separators. Liquid-liquid separators are fundamentally the same as gas-liquid separators except that they must be designed for much lower velocities. It is clear that the difference in density between two liquids is less than between gas and liquids hence separation is more difficult.

Scrubber or Knockout Drum: A vessel designed to handle streams with high gas-to-liquid ratios. The liquid is generally entrained as mist in the gas or is free-flowing along the pipe wall. These vessels usually have a small liquid collection section. The terms are often used interchangeably.

Slug Catcher: A particular separator design able to absorb sustained in-flow of large liquid volumes at irregular intervals. Usually found on gas gathering systems or other two phase pipeline systems. A slug catcher may be a single large vessel or a manifolded system of pipes.

Three Phase Separator: A vessel used to separate gas and two immiscible liquids of different densities (gas, water, and oil).

Separation vessels usually contain four major sections, plus the necessary controls. The primary separation section, A, is used to separate the main portion of free liquid in the inlet stream. It usually contains an inlet nozzle which may be tangential, or a diverter baffle to take advantage of the inertial effects of centrifugal force or an abrupt change of direction to separate the major portion of the liquid from the gas stream. Vendors offer various configurations.

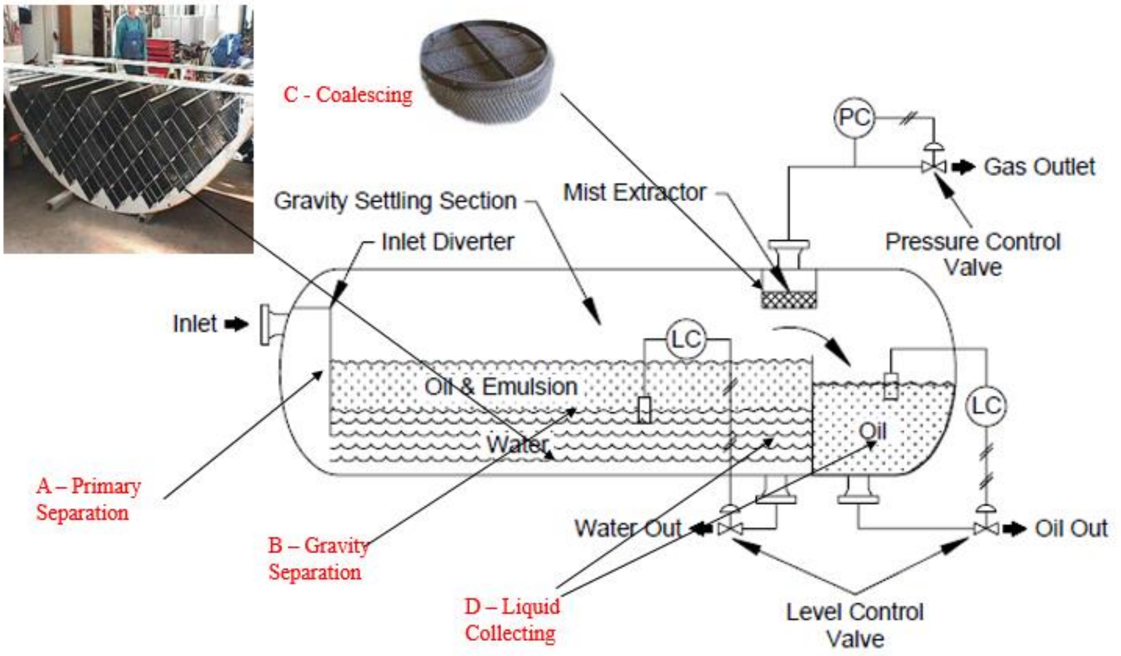


The secondary or gravity section, B, is designed to utilise gravity to enhance separation of entrained droplets. It consists of a portion of the vessel through which the gas moves at a relatively low velocity with little turbulence.

The gas coalescing section, C, utilises a coalescer or mist extractor which can consist of a series of vanes, a knitted wire mesh pad, or cyclonic passages. This section removes entrained droplets of liquid from the gas by impingement on a surface where they coalesce. For a three phase separator oil and water droplet coalescence can be achieved using tilted plate type devices.

The liquid collection section, D, acts as receiver for all liquid removed from the gas in the primary, secondary, and coalescing sections. Depending on requirements, the liquid section should have a certain amount of surge volume, for degassing or slug catching.

6.1 Three Phase Separator



In this configuration it is usual that liquid residence time is the dominant design condition as the horizontal orientation favours liquid separation.

The number of stages is influenced by;

– Flowing well head pressure – inlet pressure
– Compression requirements
– Export oil vapour pressure specification
– BS&W (Water) specification

– Salt specification

– Product recovery

Separator size is a function of;

– Product specification

– Fluid mass rates

– Fluid rheology

Key features are;

– Primary separation section to separate the bulk of the liquid from the gas

– Sufficient capacity to handle liquid surges

– Sufficient liquid residence time to allow small droplets to settle out

– An inlet device to reduce turbulence and velocity in the main separation section

– Ensure gas velocity does not result in liquid entrainment

– A mist extractor to capture entrained droplets

– Pressure and liquid level controls

– Relief and blowdown provision

– Sand washing provision

Internals design is often critical to efficient separator operation. The following sketch is a cross section of an offshore separator showing;

– Inlet device to reduce liquid momentum (centrifugal/impingement)

– Distributor plate

– Baffle plates to prevent by-passing, sloshing due to vessel motion and surges in feed rate

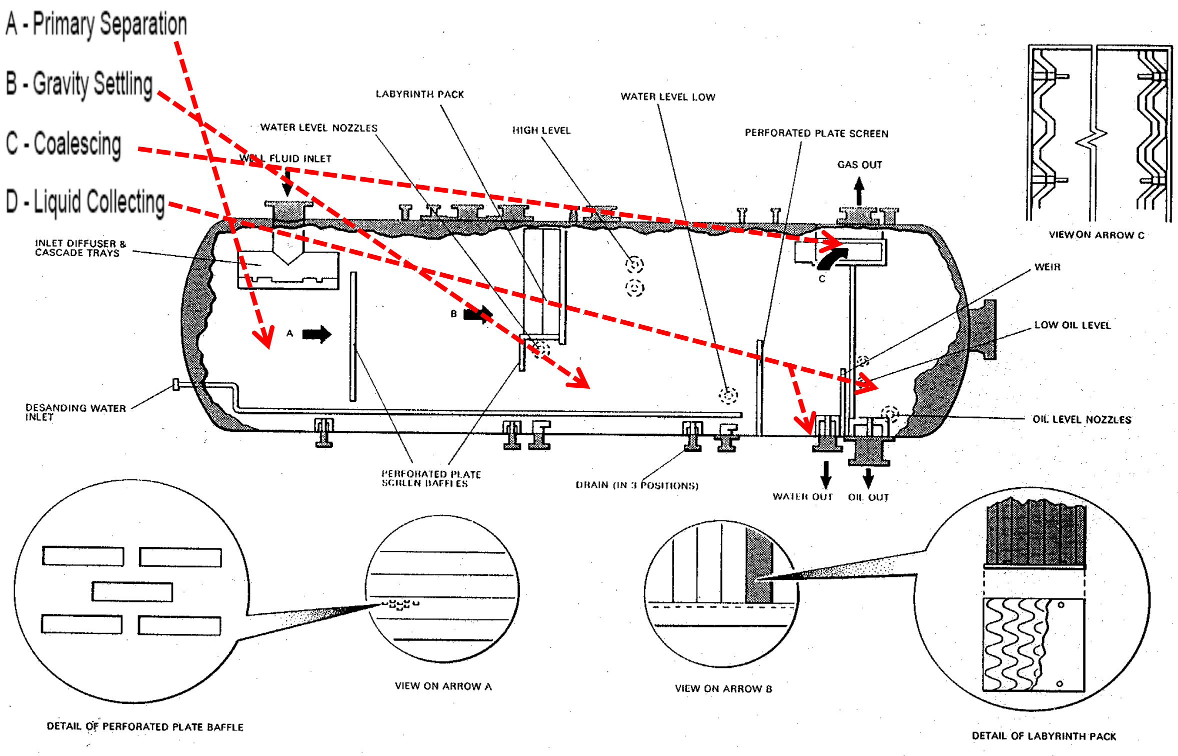
– Coalescer pack to provide surface area for small droplets to coalesce to larger ones, thus enhancing liquid/liquid separation

– Vane packs or demisters to collect oil droplets from the gas

– Vortex breakers to prevent gas underflow

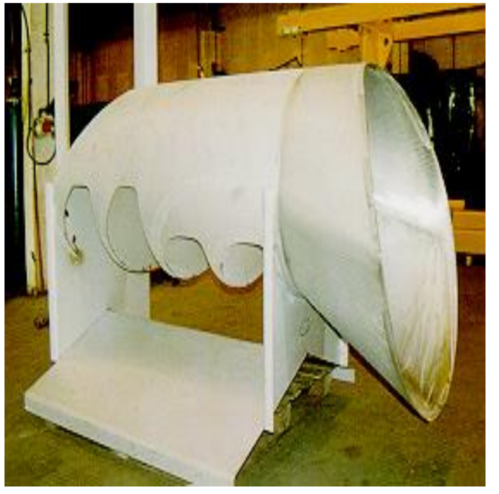
– Sand jets to remove sand from the separator

– Foam packs to break foams – often referred to as Dixon plates

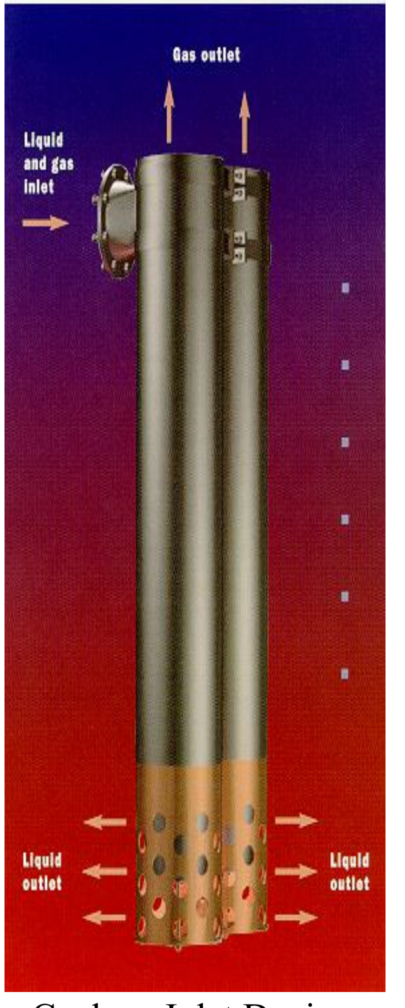


Note that separator design is empirical and a topic of much debate within the industry. Some more detail on internal arrangements are shown.

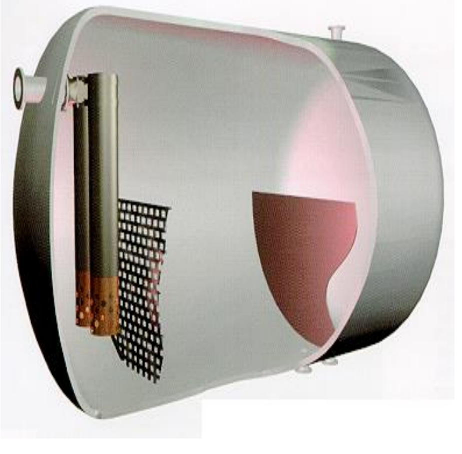
Baffle Plate Set



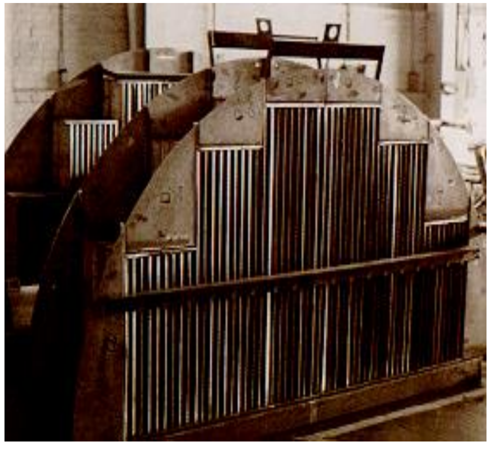
Inlet Diffuser & Cascade Tray



Cyclone Inlet Device



Cyclone Inlet Device with Perforated Baffle Plate



Foam Reducing Pack Assembly

This device provides primary V/L separation. The liquids are delivered below the liquid surface

6.2 Stokes Law

Droplet movement can be represented by Stokes Law; if a droplet is falling in a viscous fluid due to gravity, then a terminal settling velocity is reached when the frictional force combined with the buoyant force exactly balance the gravitational force. The resulting settling velocity is given by:

$$v_{settle} = \frac{d^2 \cdot (\rho_w - \rho_o)}{18 \cdot \mu} \cdot g$$

Settling velocity, v_{settle} – m/s

Density, ρ – kg/m^3,

Viscosity, μ – Pa.s

Droplet diameter, d – m

By inspection it is clear that the larger the droplet diameter, the greater the density difference between the two media and the lower the viscosity of the continuous phase then the higher the settling velocity. The higher the velocity the lower the required residence time for settling, thus the smaller the vessel required.

Stokes law states that whenever a relative motion exists between a droplet and a surrounding fluid, the fluid will exert a drag upon the particle. In steady flow, the drag force is;

$$F_D = \frac{C_D A_P \rho u^2}{2}$$

where F_D = drag force
C_D = drag coefficient
A_P = projected particle area in direction of motion
ρ = density of surrounding fluid
u = relative velocity between particle and fluid

A particle falling under the action of gravity will accelerate until the drag force balances gravitational force at a settling velocity

$$u_t = \sqrt{\frac{2gm_p(\rho_p - \rho)}{\rho\rho_p A_P C_D}}$$

where g = acceleration of gravity
m_p = particle mass
ρ_p = particle density

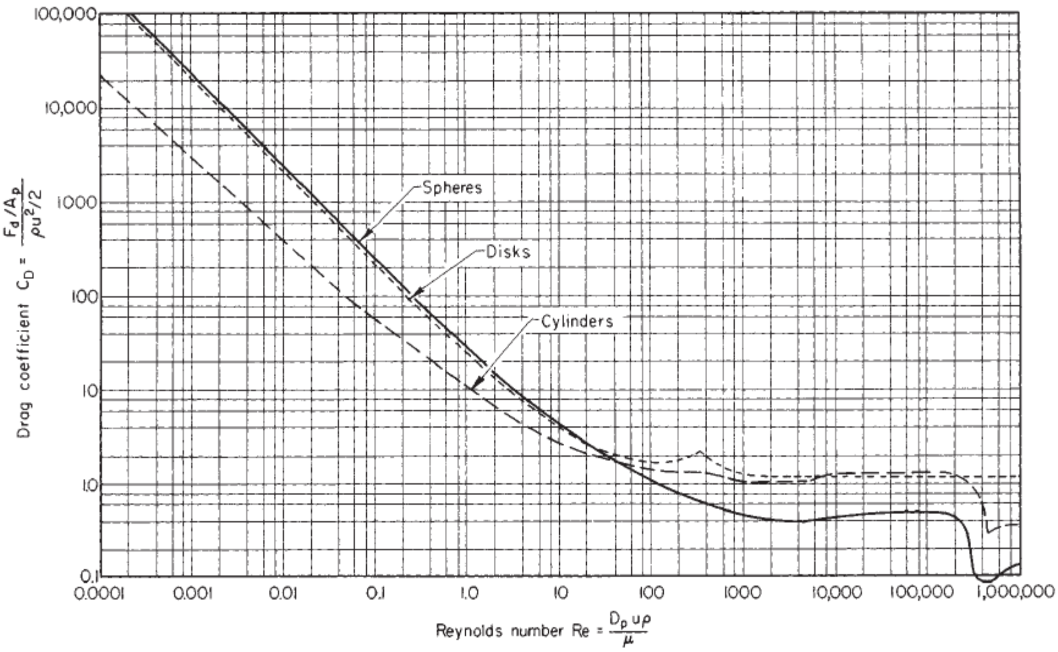
For spherical particles the equation becomes;

$$u_t = \sqrt{\frac{4gd_p(\rho_p - \rho)}{3\rho C_D}}$$

The drag coefficient for rigid spheres is a function of the particle Reynolds Number. At Low Reynolds number.

$$C_D = \frac{24}{\mathrm{Re}_p} \qquad \mathrm{Re}_p < 0.1$$

Drag coefficients are shown in the following figure. Stokes law is derived by substituting $C_D = 24/\mathrm{Re}_p$ into the above equation. $\mathrm{Re}_p = \rho . u_t . d_p/\mu$



Drag coefficients for spheres, disks, and cylinders: A_p = area of particle projected on a plane normal to direction of motion; C = overall drag coefficient, dimensionless; D_p = diameter of particle; F_d = drag or resistance to motion of body in fluid; Re = Reynolds number, dimensionless; u = relative velocity between particle and main body of fluid; μ = fluid viscosity; and ρ = fluid density. (*From Lapple and Shepherd,* Ind. Eng. Chem., **32**, 605 [1940].)

6.3 Application of Stokes Law

The direct application of Stokes law has limited use for the design of offshore separators. The droplet size distribution is more often unknown which limits the use of Stokes law. Some effort has been made to quantify droplet sizes but most separator designers would agree that this is an area of great uncertainty.

As a rough indication, the approximate size of the largest droplets, $d_{p,max}$, formed in a separator feed pipe with diameter d_{fp} is given by:

$$d_{p,max}/d_{fp} = 4.5\{\sigma/(\rho_G v^2{}_G d_{fp})\}^{0.6}(\rho_G/\rho_L)^{0.4}$$

The smallest drops will generally have a diameter five to ten times smaller than $d_{p,max}$

ρ_L, ρ_G, Oil and Gas Density, kg/m3

$d_{fp.}$ Pipe diameter, m

σ, Interfacial tension, N/m

V_G, Gas Velocity, m/s

Because of the limitations associated with droplet size and droplet interaction, separators are often designed using empirical residence times derived from years of operational experience with similar hydrocarbons. Note that increasing g would also enhance settling velocity.

Worked Example

How long does it take for a 500μm (micrometer) droplet to settle through a distance of 1 meter ?

Water Density: 1000 kg/m^3

Oil Density: 760 kg/m3

Oil Viscosity: 4 cP (0.004 pa.S)

Settling velocity:

$$v = \frac{(0.0005)^2 \times (1000 - 760)}{18 \times 0.004} \times 10 = 0.0083\, m/s$$

Thus settling time:

t = 1/v = 1/0.0083 = 120 seconds

If the oil had a higher density and viscosity;

Oil Density: 900 kg/m3

Oil Viscosity: 100 cP

Settling velocity: 0.000139 m/s

Settling time: 7200 seconds

Or 120 minutes

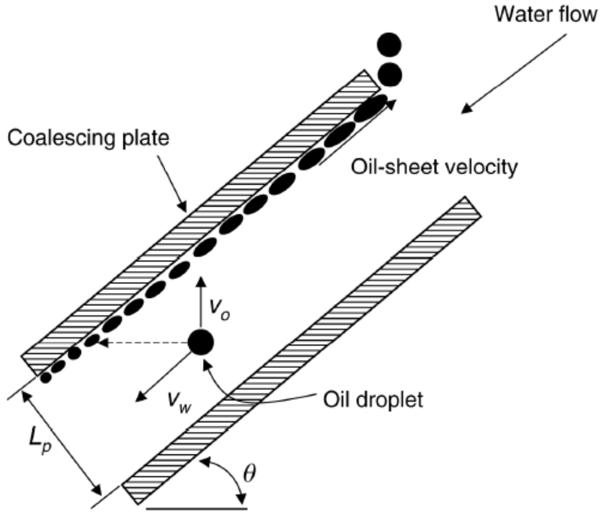
120 minutes would normally be impractical – the vessel would be too large for offshore applications. Thus the chemical engineer would be seeking to increase the temperature to reduce the viscosity, optimise demulsifier selection and use droplet growth promoting devices.

6.4 Droplet Growth

6.4.1 Surface Tension

Surface tension plays a significant role – it is the elastic tendency of a fluid surface which makes it acquire the least surface area possible. The smaller the surface tension the smaller the droplet size.

An angled plate assembly is commonly used to grow droplets. They are often termed tilted plate interceptors, corrugated plate interceptors and are also referred to as API coalescers. As oil and

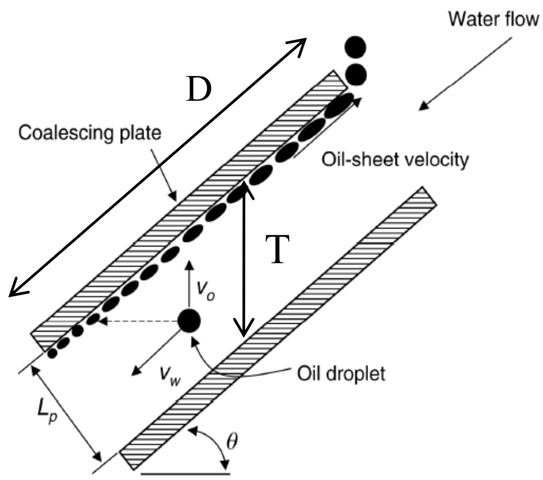


water flow down through the plates, oil droplets will rise due to buoyancy effects. The oil droplet will be trapped by the angled plate above it and will continue to rise following the lower surface of the top plate. As it does so the oil droplet will coalesce with other trapped rising oil droplets. Drop growth will occur as the droplet moves to the top of the plate pack where it will be released as a larger droplet. The same principal can be used to remove water droplets – these would fall to the lower plate and travel downwards.

Flow through the plates should be laminar with a Reynolds number typically 500.

Using Stokes law;

$$v_0 = \frac{d^2 \cdot (\rho_w - \rho_o)}{18 \cdot \mu} \cdot g$$



The following will hold;

$H = V_o.T$

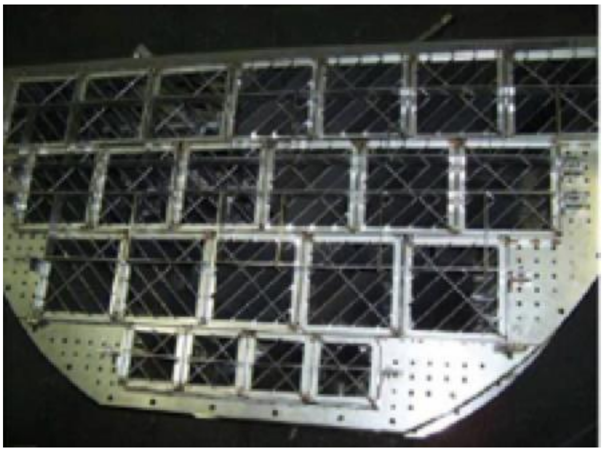
$T = D_p/V_w$

H distance travelled by particle (m)

T is residence time in plate (s)

Using the above gives a droplet size which should be captured as;

$$d = \sqrt{(H \times V_w \times 18 \times \mu) \div (g \times D_P\ (\rho_w - \rho_o))}$$



Angled plate internals

6.5 Separator Sizing

The sizing of a separator is generally determined by the required residence time for separation. Typical values given by API are shown.

Oil Relative Density	Retention Time (min.)
< 0.85	3 – 5
> 0.85 > 100 °F	5 – 10
80 – 100 °F	10 – 20
60 – 80 °F	20 – 30

API Recommendations

Specification for
Oil and Gas Separators

API SPECIFICATION 12J

This residence time allows for separator dimensions to be estimated using the geometry of a cylinder. A check is then made that the gas velocity in the vapour space above the liquid is less than the following maximum velocity (NORSOK standard for Process Systems P100)

$$v_s = k \cdot \left(\frac{\rho_l - \rho_g}{\rho_g} \right)^{0.5} \times \left(\frac{L}{6} \right)^{0.58}$$

v_s = gas velocity (m/s)

k = constant typically 0.133

L = separator length (t/t) (m)

ρ_l = liquid density (kg/m^3)

ρ_g = gas density (kg/m^3)

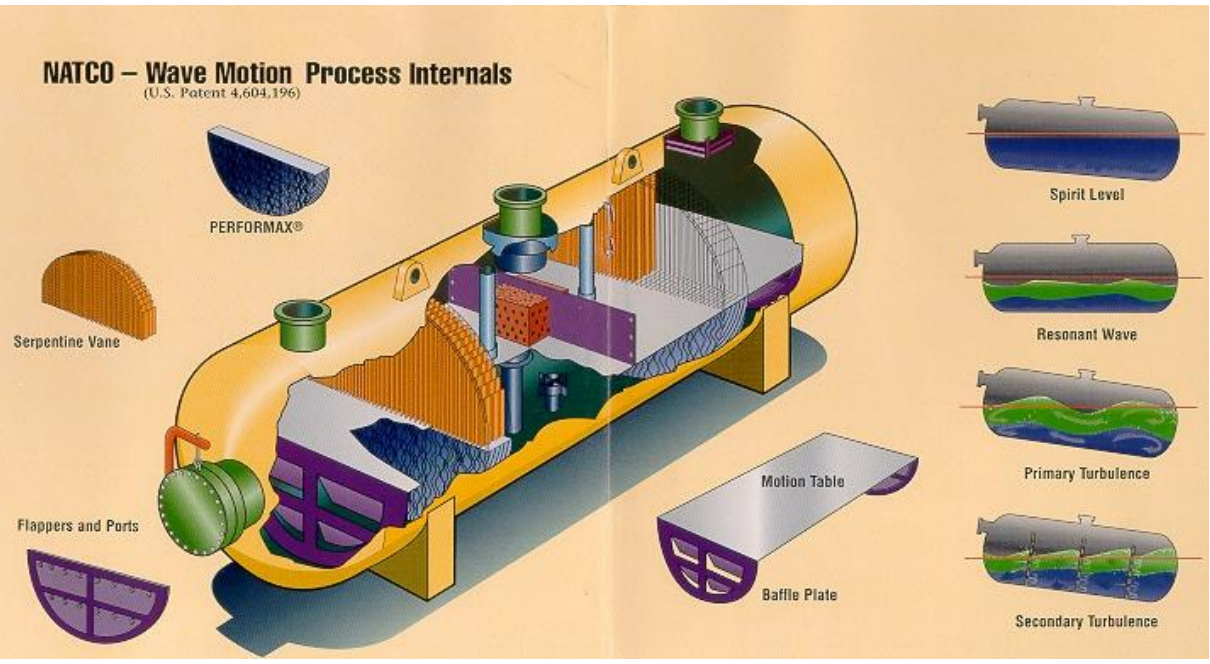
For each vessel design, a combination of length and diameter exists that will minimize the cost of the vessel. In general, the smaller the diameter of a vessel, the less it will cost. However, decreasing the diameter increases the fluid velocities and turbulence. As a vessel diameter decreases, the likelihood of the gas re-entraining liquids or destruction of the oil/water interface increases. Experience indicates that the ratio of the seam-to seam length divided by the outside diameter should be between 3 and

Operating Pressure (bara)	Typical L/D
0 to 20	3
20 to 40	4
Over 40	5

5. The enclosed table shows the higher the pressure the smaller the diameter – this allow for a smaller wall thickness to retain the internal pressure.

6.6 Motion Effects

If the separator is located on a floating vessel it will clearly be subject to motions. The design of the separator has to recognise the effects motion will have on separation characteristics.
A typical design for a separator subject to motion is shown. Here the multi-phase fluid is introduced in the centre at the top of the vessel. The fluid splits and moves across the top of a motion table or heave plate. Gas is disengaged and flows out at either end of vessel. The liquids (oil and water) flow into a lower chamber where they are retained by flappers. In the lower section oil water separation is facilitated with oil and water removed by weir pipes.



Separator analysis frequently involves CFD (computational fluid dynamics) to design and verify whether equipment will operate in motion conditions.
When sizing the separators allowances must be made for the spirit-level effect, especially in rough seas. The liquid volume must be increased to allow for motion as the residence time in the 'shallow end' will be reduced. Similarly the vapour space needs to be increased to prevent high gas velocity in the 'deep end'.

6.7 Computational Fluid Dynamics

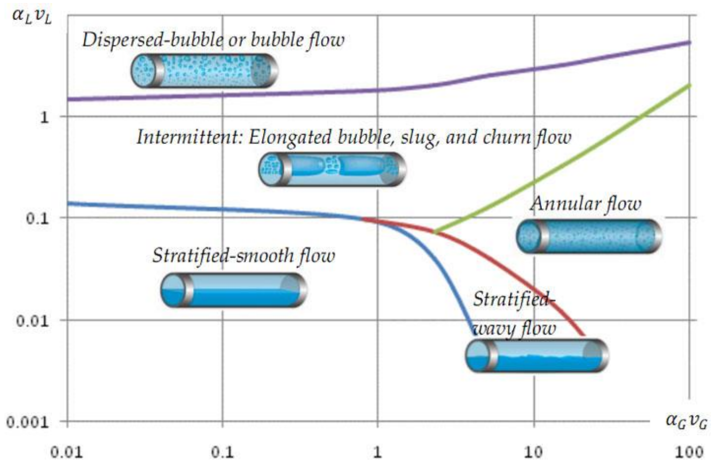
As a consequence of the ready availability of desktop processing capability, CFD is being used in many aspects of equipment design. It is analytical technique for describing fluid and heat flow in two/three dimensions. Mostly using Navier-Stokes equations.

Applications include;

- Separation equipment
- Combustion
- Rotating Equipment
- Erosion
- Dispersion

6.8 Inlet Feed Flow Pattern

The incoming flow pattern to a separator can affect its performance. A continuous flow of the phases provides conditions for effective separation. The most troublesome flow regime is slugging or intermittent flow. Here discrete packs of liquid and gas are delivered to the separator. This intermittent flow can cause severe problems for level and pressure control. Inlet flow conditions can be estimated using flow regime charts.



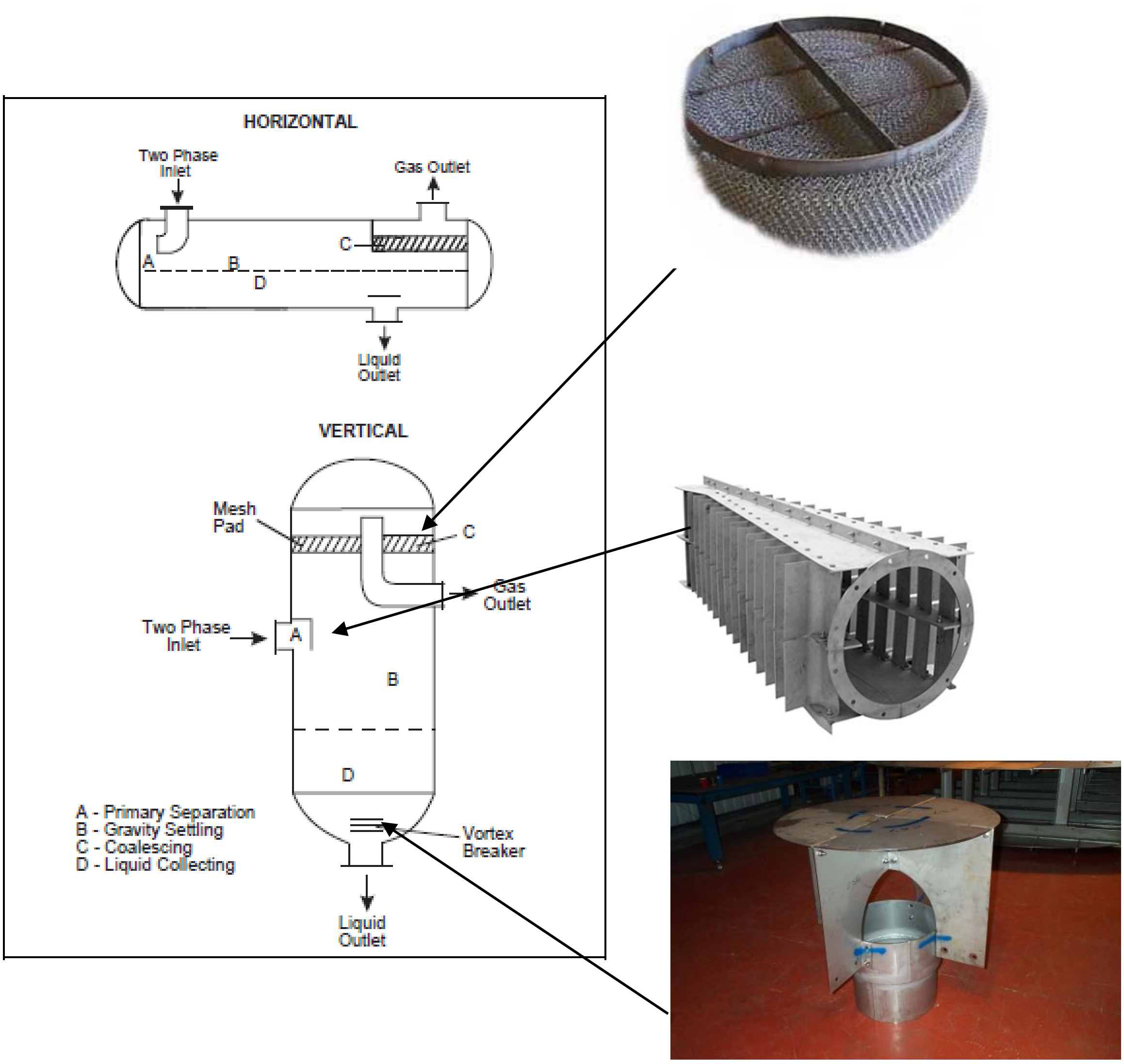
6.9 Caryover and Carryunder

Clearly a main function of the separator is to provide a liquid free gas and gas free liquid. Dependent upon the properties of the fluids being handled and the effectiveness of the separator design this is not always achieved. Should significant carryover or carryunder be experienced performance of downstream equipment can be seriously impaired. Heat and Mass balance simulators can not predict such non-equilibrium effects.

6.10 Diluent Injection

Statoil are utilising diluent injection on the Mariner field. Mariner is a very heavy, viscous oil – 0.91 sg, 100 cP. Clearly by inspection of Stokes Law, gravity separation for water removal will be difficult as a consequence of the close density difference to water and the high viscosity. Well injection of a diluent of lower sg and viscosity makes the mixed diluent and Mariner crude much easier to treat.

7 Two Phase Separator – Vertical Scrubber



This arrangement is most often used when the dominant phase is gas. They are used to remove liquids from a gas stream. The efficiency of liquids removal is of prime importance if the unit is protecting downstream equipment such as a compressor.

Variants of the Souders Brown equation are used for diameter estimation:

$$U = k \cdot \left(\frac{\rho_l - \rho_g}{\rho_g} \right)^{0.5}$$

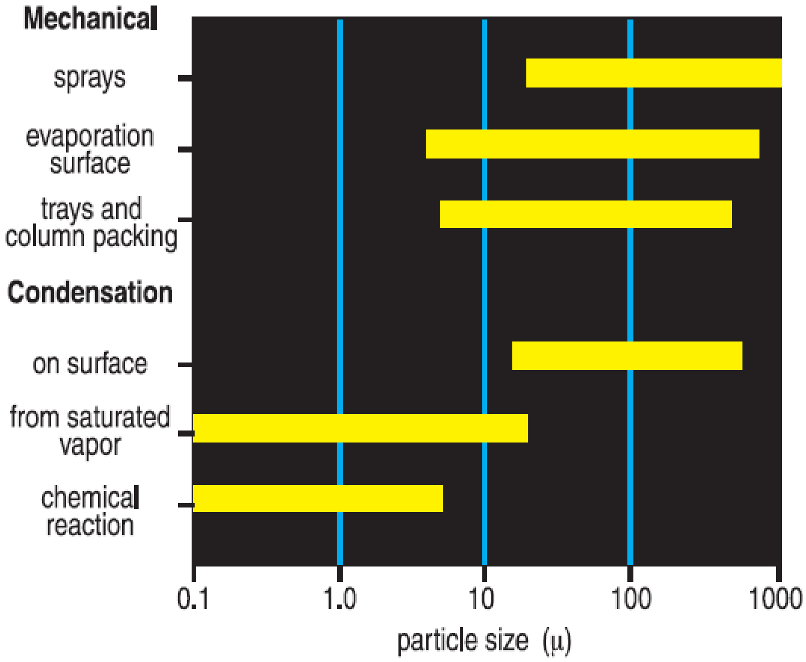
U = Maximum superficial gas velocity (m/s)

k = 0.107 wire mesh demister, 0.061 no wire mesh demister

ρ_l = liquid density (kg/m3)

ρ_g = gas density (kg/m3)

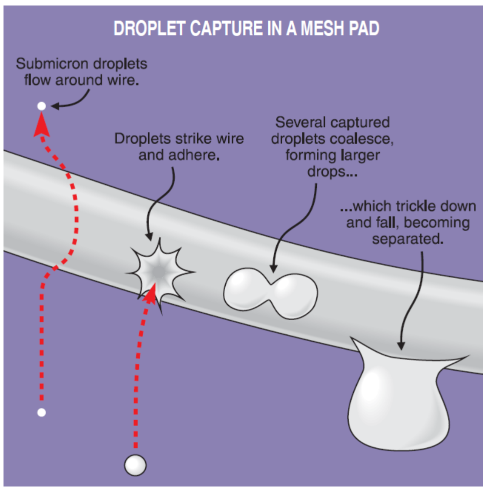
Typical mist characteristics are shown



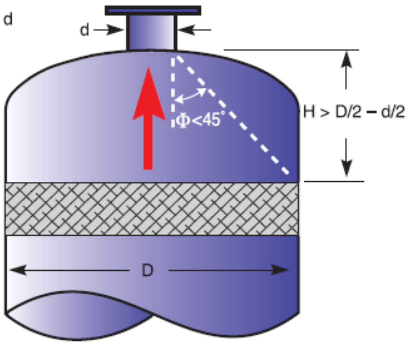
Mist/liquid entrainment is typically controlled using a demist pad or a vane pack.

7.1 Demist – Wire Mesh Pads

Wire mesh mist eliminators are produced as a bed of knitted mesh that presents a tortuous path and large surface area to the droplets entrained in a gas stream. Separation is achieved by impingement on, and capture by, the filaments of the mesh where the droplets coalesce and drain.

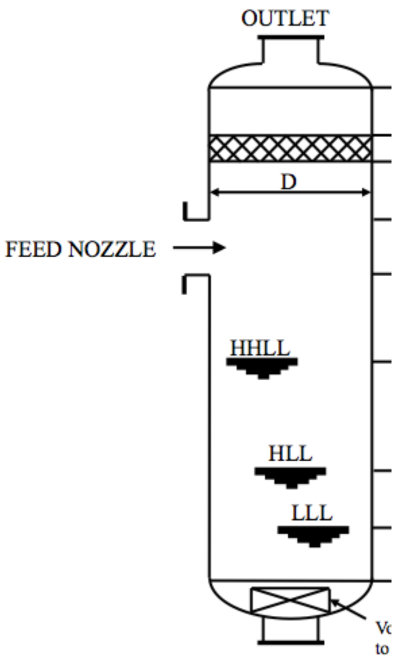


Standard designs are available for routine applications, manufacturers claim separation efficiency down to droplet sizes as small as 2 μm, and with a pressure drop typically less than 2.5 mbar.



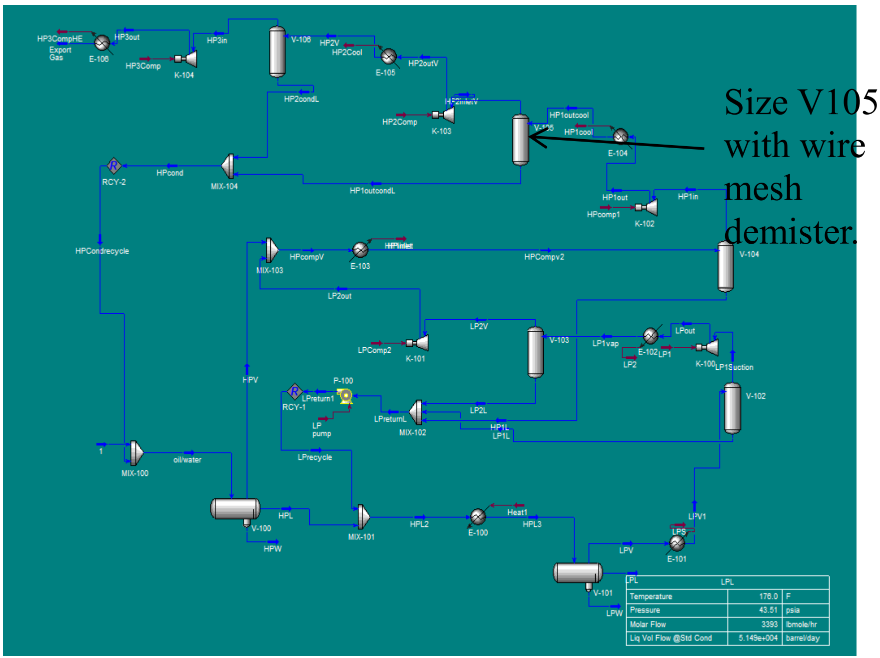
7.2 Vertical Separator Sizing

Typical design rules are shown.



Worked Example

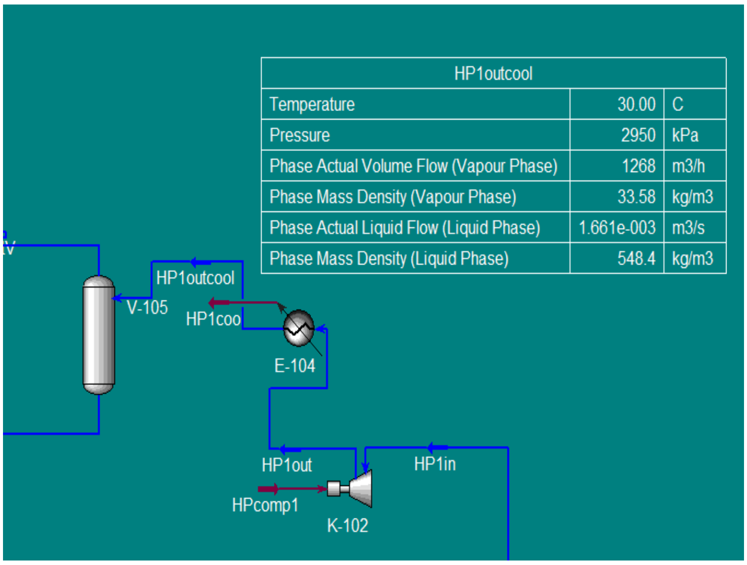
A heat and mass balance has been finalised and a sizing has to be prepared for a vertical vessel



protecting a compressor. The vessel is fitted with a wire mesh pad.

The engineer extracts the required data from the simulation output and uses limiting velocity expression.

$$U = k \cdot \left(\frac{\rho_l - \rho_g}{\rho_g} \right)^{0.5}$$



U = 0.107 x ((548.4-33.58)/33.58)) $^{0.5}$

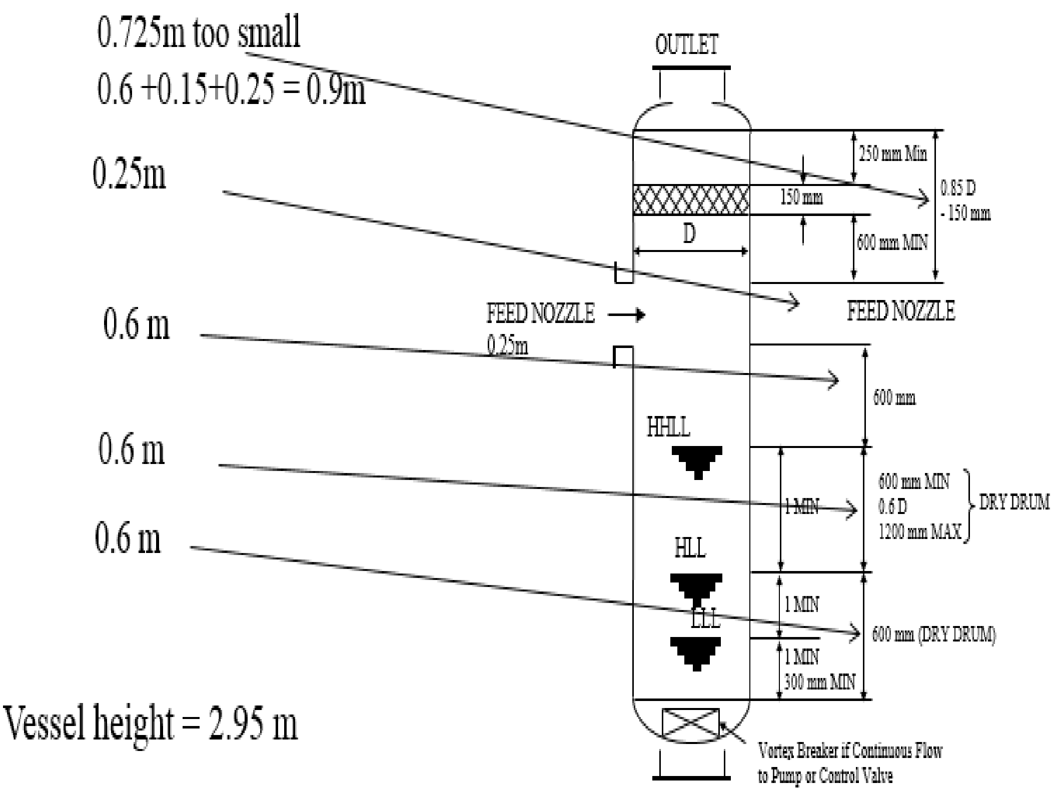
U = 0.42m/s

Vessel CSA = 1268/(3600*0.42)

= 0.84 m2

Vessel Diameter = 1.03m

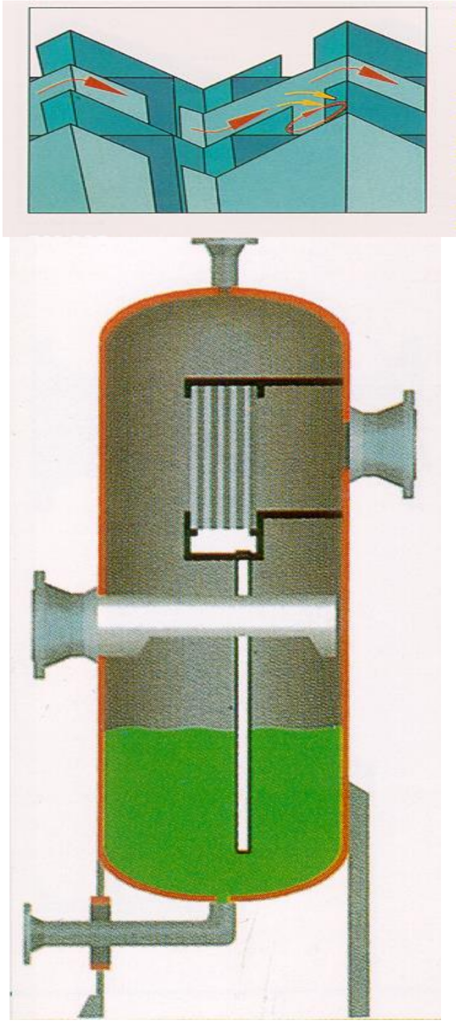
Use can then be made of the standard dimensions



3 min liquid residence, liquid volume = 0.3 m3

Height of liquid = 0.36 m (too small for control)

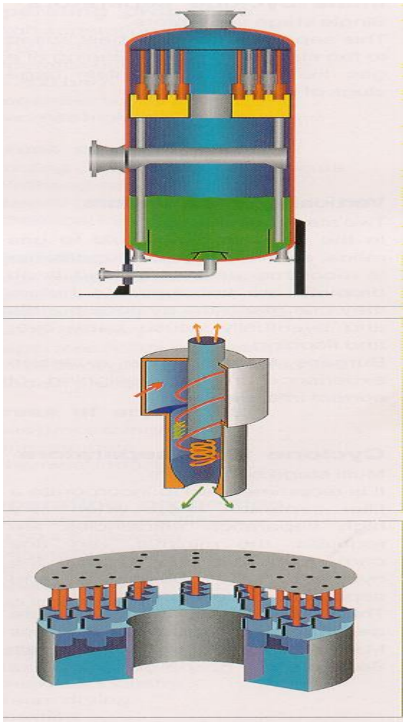
7.2.1 Vane Packs



Vanes differ from wire mesh in that they do not drain the separated liquid back through the rising gas stream. Rather, the liquid can be routed into a downcomer, which carries the fluid directly to the liquid reservoir. The vanes remove fluid from the gas stream by directing the flow through a torturous path. The liquid droplets, being heavier than the gas, are subjected to inertial forces which throw them against the walls of the vane. This fluid is then drained by gravity from the vane elements into a downcomer. Vane type separators generally are considered to achieve the same separation performance as wire mesh, with the added advantage that they do not readily plug and can often be housed in smaller vessels. As vane type separators depend upon inertial forces for performance, turndown can be a problem.

Vane type separator designs are proprietary and are not easily designed with standard equations. Manufacturers of vane type separators should be consulted for detailed designs of their specific equipment.

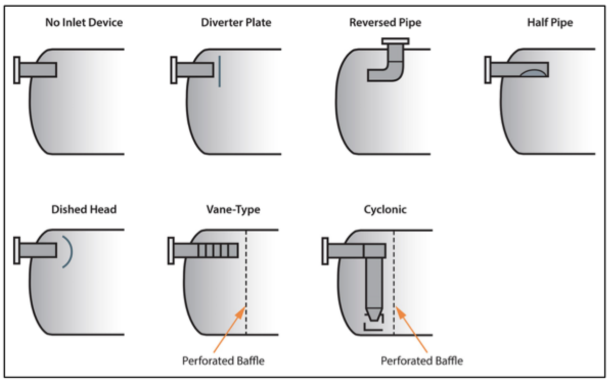
7.2.2 Demisting Cyclonic Outlets



The use of a cyclone bank at the outlet is a means of more efficiently capturing entrained liquid droplets. It is generally a more expensive option being used when a high degree of liquid protection is required.

7.3 Vessel Nozzles

Nozzles are an important part of vessel design.



The inlet nozzle affects droplet size distribution. The design will impact pressure drop. Typically there no upstream bends within 10 diameters to avoid mal distribution of flow. The nozzle velocity is set to limit erosion.

Typical values:

ρv^2 = 1000 kg/m.s^2 for open pipe

ρv^2 = 1500 kg/m.s^2 for half pipe

Higher values are possible for proprietary designs (6000 - 10000)

Outlet nozzles:

Velocity limits (entrainment, vortexing)

Typical values:

Gas ρv^2 = 3750 kg/m.s^2

Liquid v = 1 m/s

7.4 Vessel Wall Thickness

The Process Engineer will provide the information required by the Mechanical Engineers to design the required vessels.

Based upon the pressure and diameter specified by the Process Engineer the mechanical engineer will determine the wall thickness for a given material

A simplified method for wall thickness follows:

$$Wt = \frac{P_{design} \times D}{20\left(S \times E - 0.06 \times P_{design}\right)}$$

Wt = wall thickness (m)

P_{design} = design pressure (bara)

D = diameter (m)

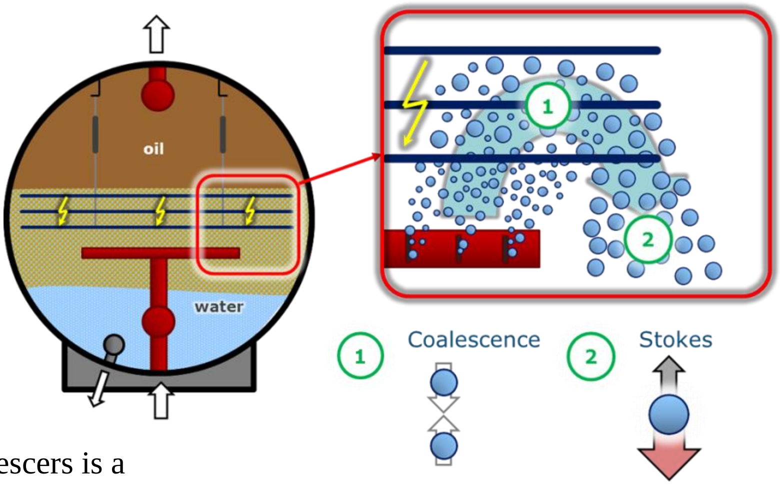
S = allowable stress (N/mm^2)

E = joint efficiency

Wall thickness is important as it will dictate the amount of material required. Hence impact on cost and weight. Weight is often a very significant factor for process plant located offshore. Pressure vessels are constructed to very strict fabrication codes. Typical standards are ASME VIII and BS 5500. The pressure vessel has to provide a minimum wall thickness for mechanical strength - see Coulson and Richardson, Vol6, 13.4.8 – Minimum Practical Wall Thickness

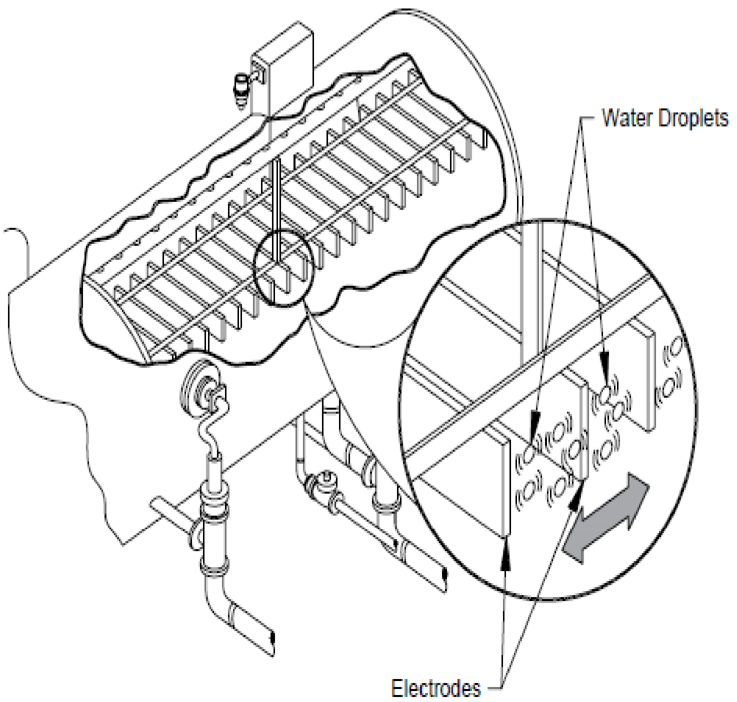
8 Electrostatic Coalescence

Gravity separation together with chemical treatment and heating may be insufficient to remove water to the low levels necessary for refinery feedstock or for tanker transportation. In this instance the polarity of the water can be utilised to promote coalescence of the water droplets. The oil containing the dispersed water is passed through an electric field. A dipole is induced into the water droplet. When two droplets with induced dipoles are close to each other, they will experience a force pulling the droplets closer promoting coalescence. The design of electrostatic coalescers is a specialist topic undertaken by equipment vendors.



Typically they have10-20 minute residence time. There is an upper limit to the inlet water concentration as too much water can short the plates. Manufacturers set limits typically up to 25 % vol water in oil. The outlet can readily achieve water specifications suitable for refineries i.e. 0.2 - 0.5 % vol water in oil.

Some electrode designs have oscillating electrical charges; thus, the water droplets are placed in a rapid back-and-forth motion. The greater the motion of the droplets, the more likely the water droplets are to collide with each other, rupture the skin of the emulsifying agent, coalesce, and settle out of the emulsion. It is imperative that the design of the vessel provides for distribution of the

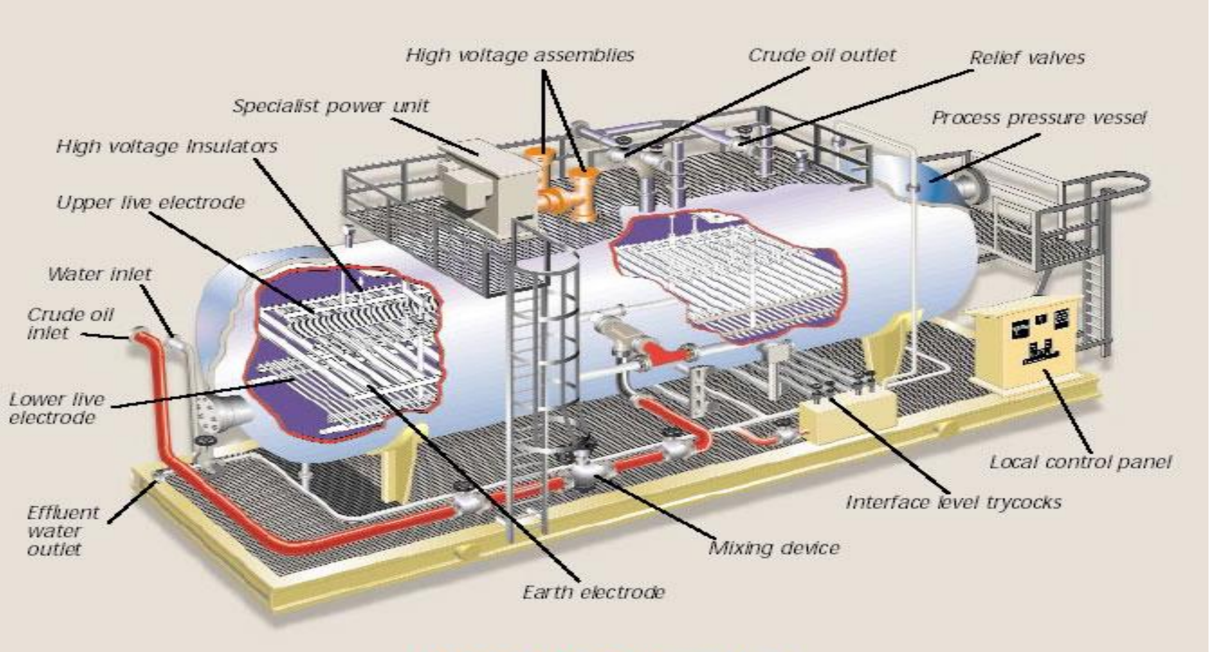


emulsion across the electrical grid. It is also essential to maintain the fluid is in the liquid phase in the electrical coalescing section. Gas evolving in the coalescing section will attract the small water droplets in the emulsion, becoming saturated with water and carrying the water up to the oil outlet. In addition, water-saturated vapours, which are highly conductive, will greatly increase the electrical power consumption. It is also important to prevent the water level from reaching the height of the electrodes. Nearly all produced water contains some salt. These salts make the water a very good conductor. Thus, if the water contacts the electrodes, it may short out the electrode grid or the transformer.

A schematic of a typical unit is shown.

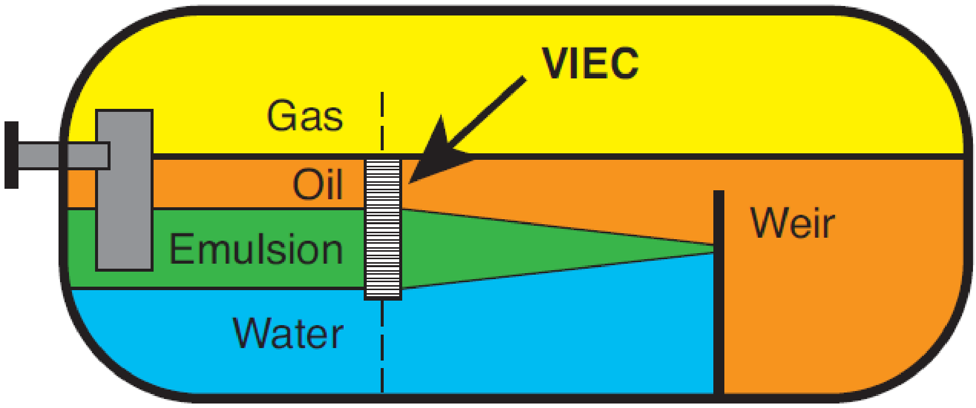
Note;

– Units run liquid full.
– Too much water can short the grids.
– Free gas will reduce performance.

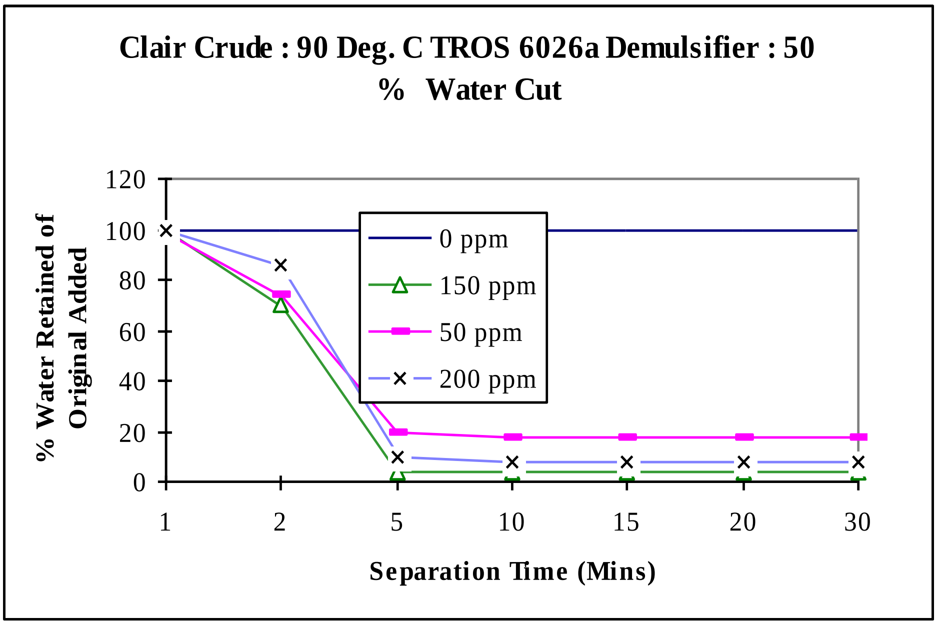


NATCO's TriGridmax Unit

Electrostatic coalescers are often very large and development work is ongoing to provide more compact systems. Once such technology is VIEC - Vessel Installed Electrostatic Coalescer.

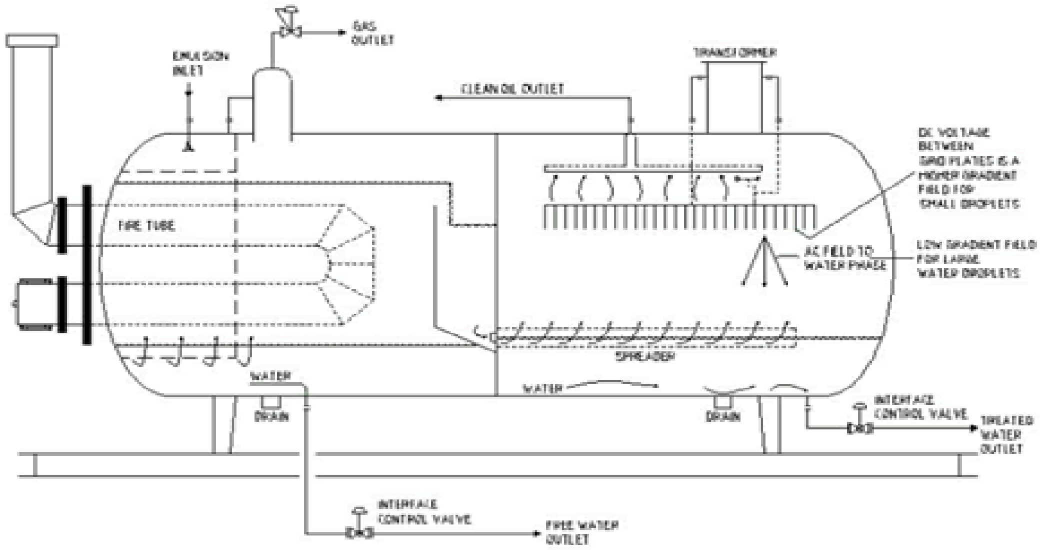


Bottle test can indicate the requirement for electrostatics. For example here the test are indicating that additional residence time above 5 minutes is not providing any more separation. Hence indicating the use electrostatics if a low residual water content is required.



8.1 Heater Treaters

As previously mentioned an essential process step is the heating of the production fluids. This can be undertaken by Heater Treaters. They are used to extract water from oil by combining a number of processing systems into a single vessel. Instead of an external heat exchanger heating up the oil water mixture the Heater Treater uses a submerged fire tube. Gas is combusted in the tube to heat up the fluid. The heated fluid then flows to another section of the vessel where gravity separation occurs - water to the bottom oil to the top. Gravity separation can be enhanced by deploying an electrostatic pack in the settling area. Such designs are seldom used offshore due to safety concerns.



8.2 Desalting

Crude oil contains salt dissolved in the entrained water droplets. Salt causes numerous operational problems to refineries;

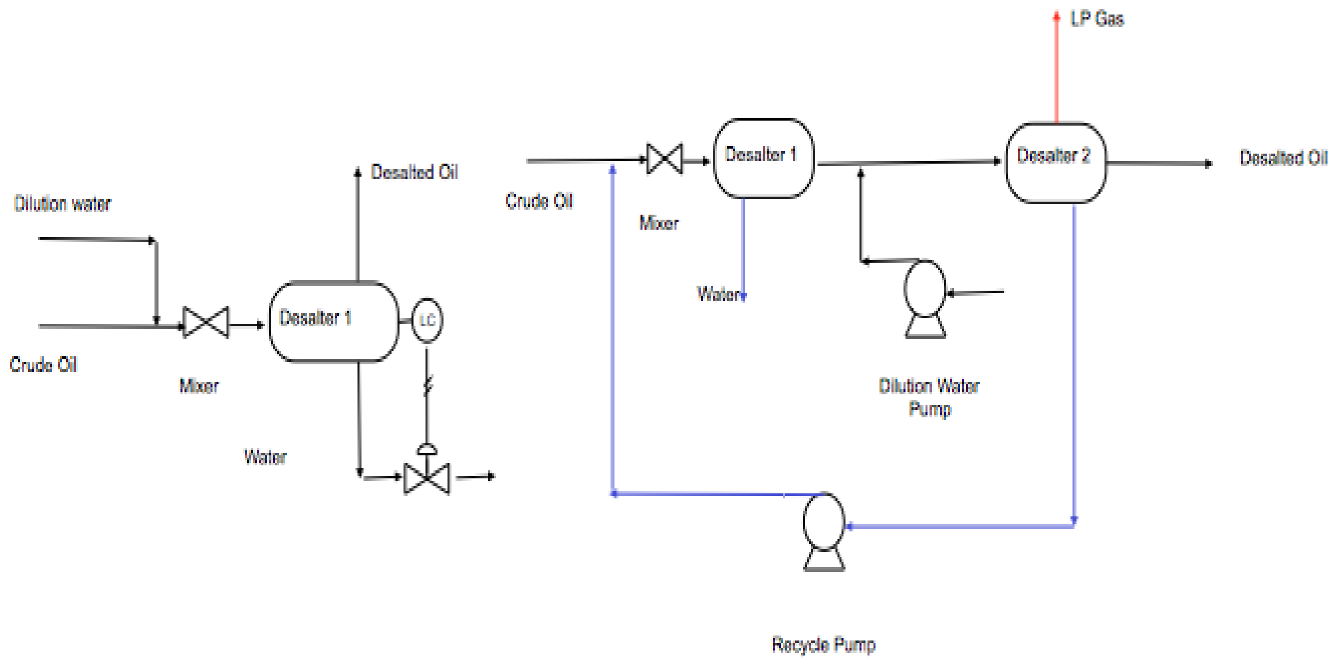
- Salt deposits in equipment
- Salt deposit reduce heat transfer and high heater wall temperatures
- Salt deposits plugs fractionations trays
- Corrosion

- Catalyst poisoning

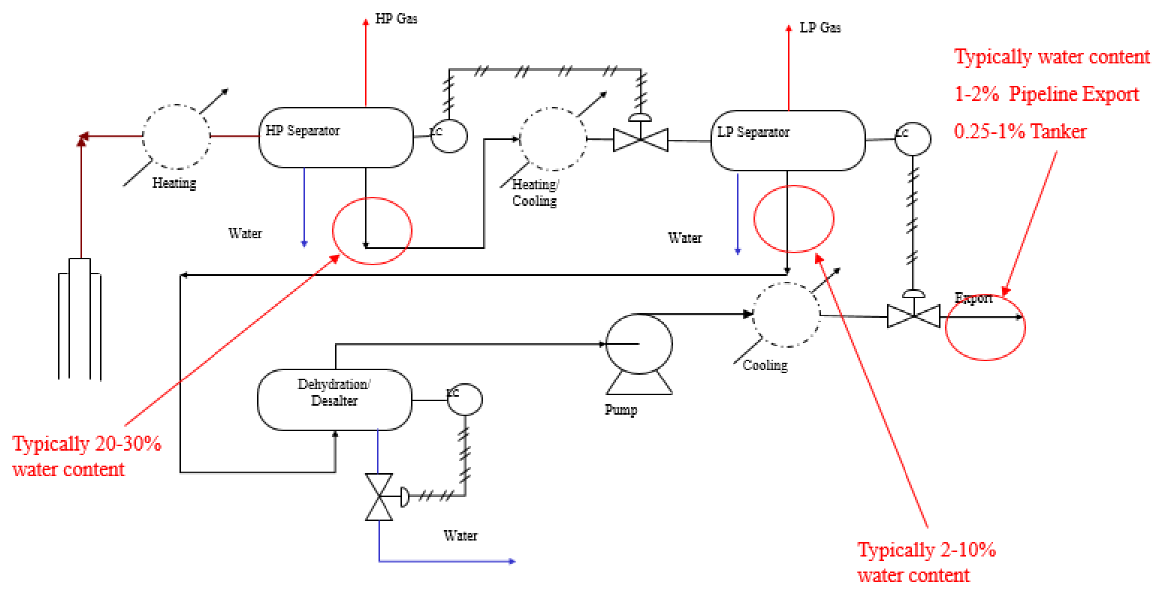
The salinity of oilfield brines varies from fresh water to saturation – approx. 30% wt (300000 ppmw). By comparison seawater is typically around 30000 – 40000ppm

The desalting process works by washing the crude with clean water and then removing the water to leave dry, low salt crude oil. For a given crude type and vessel size, factors affecting desalter efficiency include mixing efficiency, inlet header design and location, electrostatic field type and intensity, and electrode design and configuration.

A one and two stage desalting process is shown. The two stage system requires less dilution water which may be an advantage in locations where water is scarce.



8.3 Typical Separation Train Water Removal Performance



9 Production Chemistry

9.1 Demulsifiers

In oil production systems, water is almost always present in the reservoir and is co-produced with the oil. Due to the presence of emulsifying agents the oil water can form difficult to treat emulsions. Recapping, emulsion can be formed due to;

– Naturally occurring surfactants in the oil / water

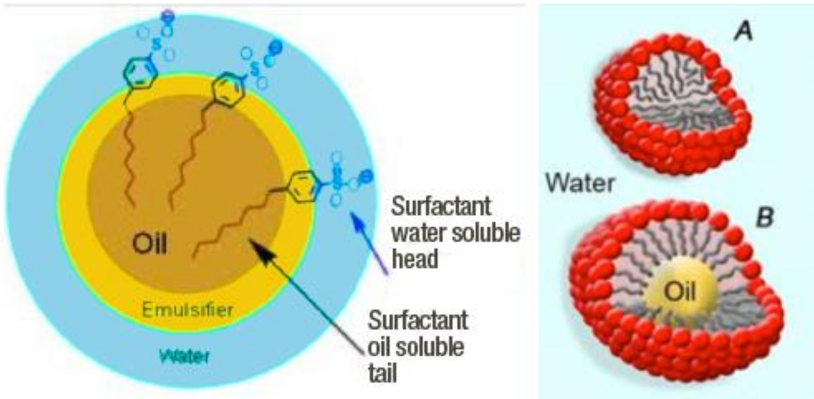
– Other chemicals (corrosion inhibitors, scale controllers, paraffin controllers

– Silts, fine solids, drilling mud, and clays

– Shearing effects resulting from turbulent flow and pumps, these fluids combine to form an emulsion

Emulsions stability varies with oil and production conditions. Given sufficient time, most emulsions will dissipate. However, in oil treatment systems time is usually a limited resource. And although emulsions may be destabilized to some extent by the addition of heat, the oil and water will not separate sufficiently in the available residence time.

To increase the rate of oil and water separation, various oilfield chemical suppliers produce demulsifiers or emulsion breakers. These chemicals are surface active, specifically targeting the emulsions. The chemicals are formulated to have one end attracted to the water phase and the other attracted



to the oil. This allows the chemical to penetrated and disrupt the emulsifying film, breaking the emulsion. Correct dosing rates are important.

Due to the vast differences in characteristics of crude oils produced throughout the world as well as the production treatment systems already in place, demulsifiers are usually formulated specifically to resolve emulsions on an individual field basis. Also, as a result of the complexity of the surfactants stabilizing these emulsions the chemicals are generally multi-component blends of chemical intermediates formulated to produce all of the requirements of an optimum treating chemical:

- Rapid water drop out,
- Zero residual emulsion,
- Sharp oil / water interface, and
- Effluent water for disposal or reuse

9.2 Foam Control

Foam formation can significantly impede separator performance. Foam test are undertaken to establish the extent of foaming. In general most separation systems will be fitted with antifoam injection systems.

Defoamers/surfactants are organic molecules, which contain an oil-soluble (hydrophobic) and a water-soluble (hydrophilic) group. Surfactants can be water-soluble or oil soluble, depending on the relative sizes of the two groups. Water-soluble surfactants are further classified as anionic, cationic, or nonionic. When dissolved in water, the first two categories will ionize, with the water-soluble portion of an anionic surfactant becoming negatively charged and that of a cationic surfactant becoming positively charged. In the case of anionic surfactants no ionization takes place upon dissolution in water; their water solubility is attributable to hydrogen bonding of active hydrogens in their water-soluble groups.

Amphoteric surfactants, which can be either cationic or anionic depending on solution pH, also exist but are usually limited to specialty applications and find relatively little use in the oilfield.

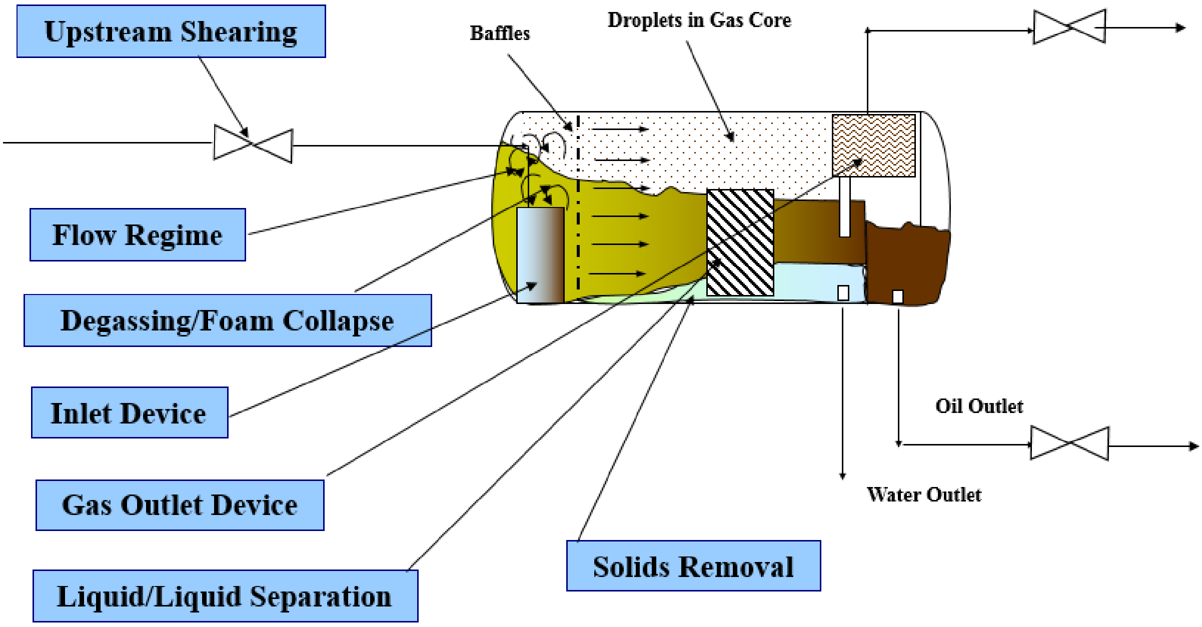
Due to the wide variation of formation chemistries and production systems in the oilfield, most surfactant products are actually blends of two or more surfactants, providing a broader range of applicability and effectiveness. Surfactants for blending must be chosen carefully in order to insure their compatibility with each other.

9.3 Napthenates

An increasing fraction of oil fields worldwide are producing crudes containing naphthenic acids – high TAN (total acid number) value. These crudes can react with calcium in the produced water to produce naphthenates which are solids. The solids deposits clog jetting nozzles, instrument connections and separator internals. They tend to accumulate at the oil/water interface. Sand encapsulation causes an increase in density until lumps drop through the water phase causing severe problems in the produced water system.

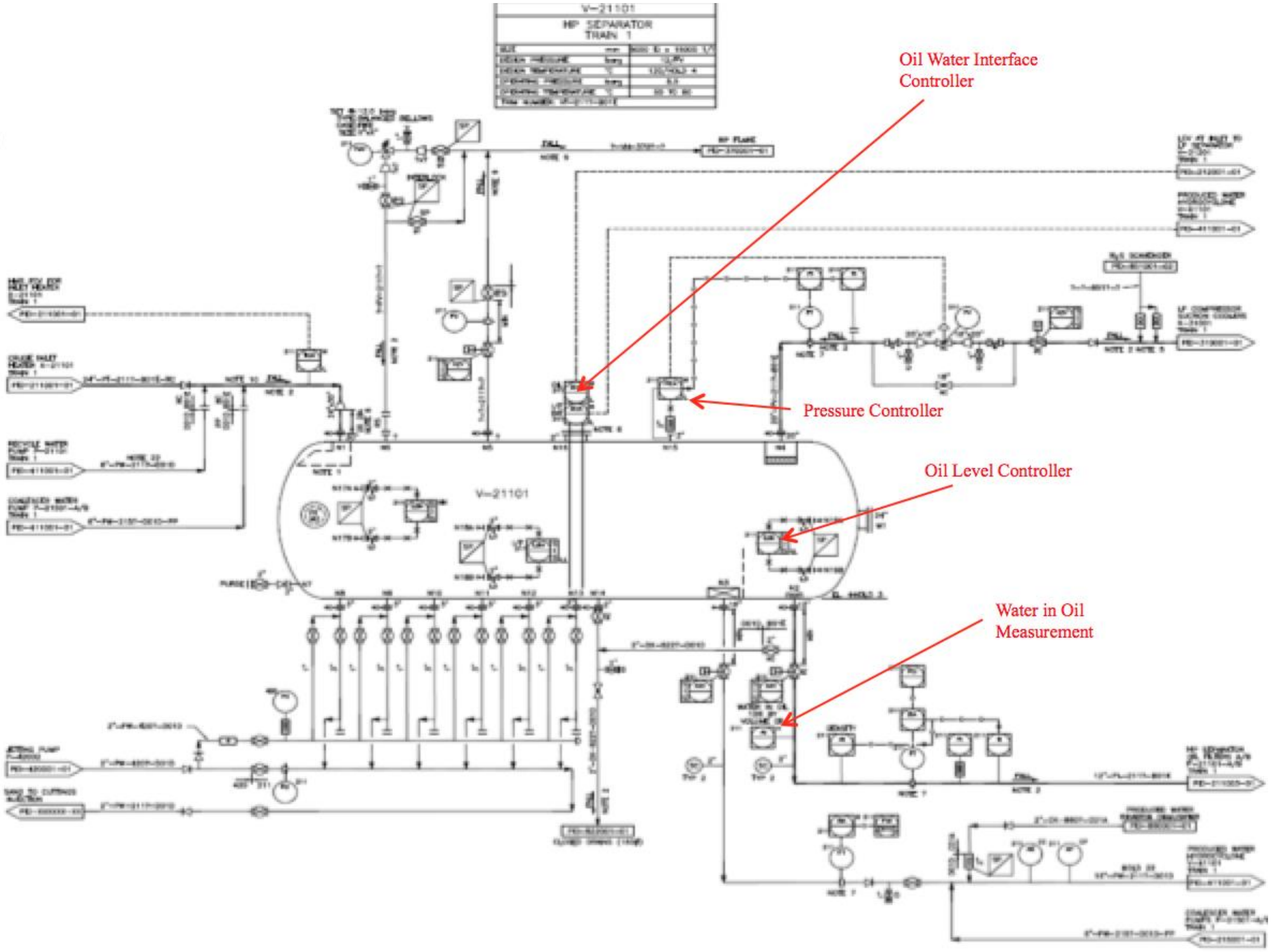
Conventional treatment is to add an acid – acetic or hydrochloric acid – hence lowering the pH and preventing the salt from forming. Whilst this may solve the naphthenate problem consequential corrosion can be severe. Chemical suppliers are working on naphthenate inhibitors as an alternative to acid treatment.

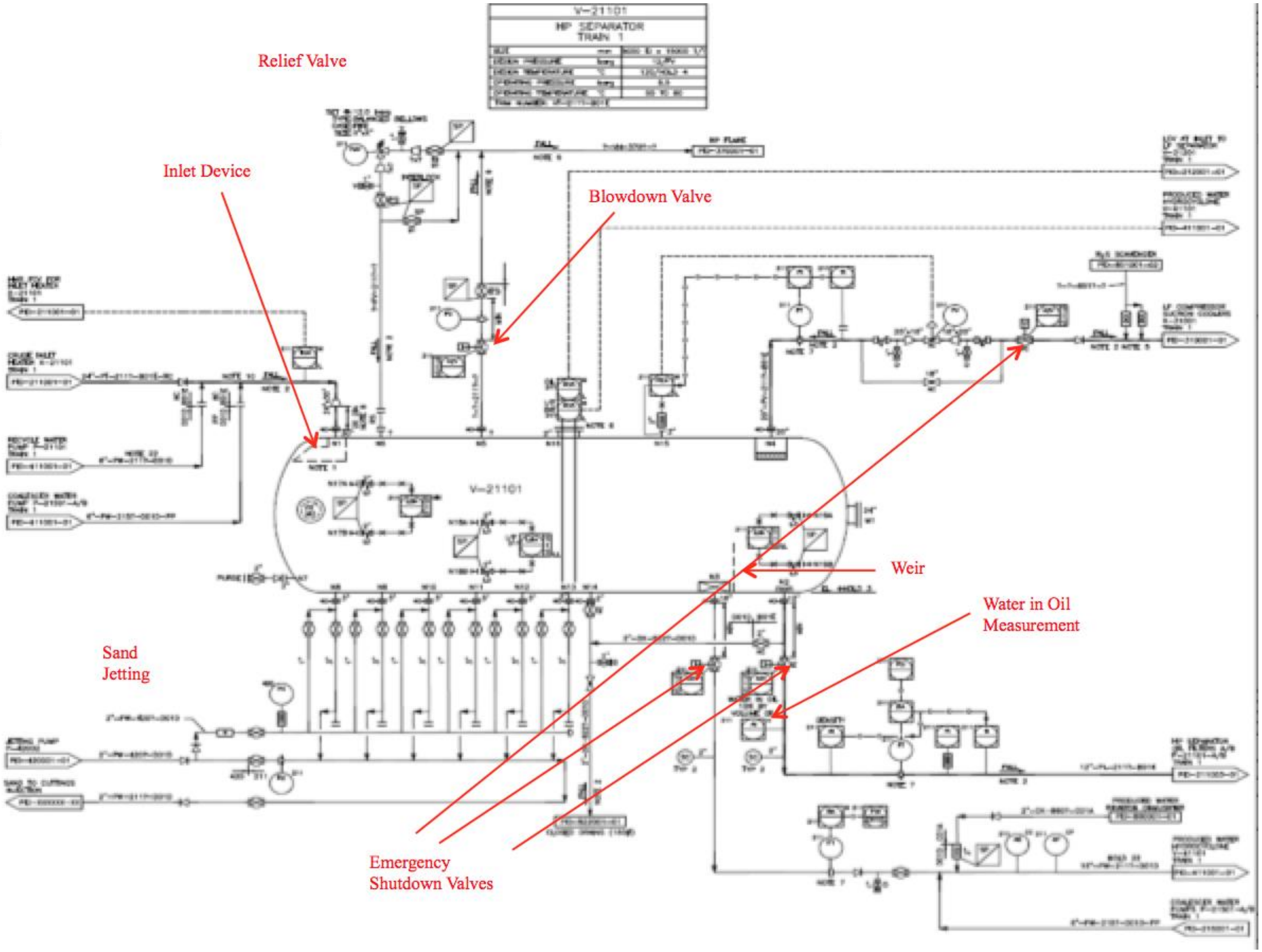
10 Separator Summary of key influencers



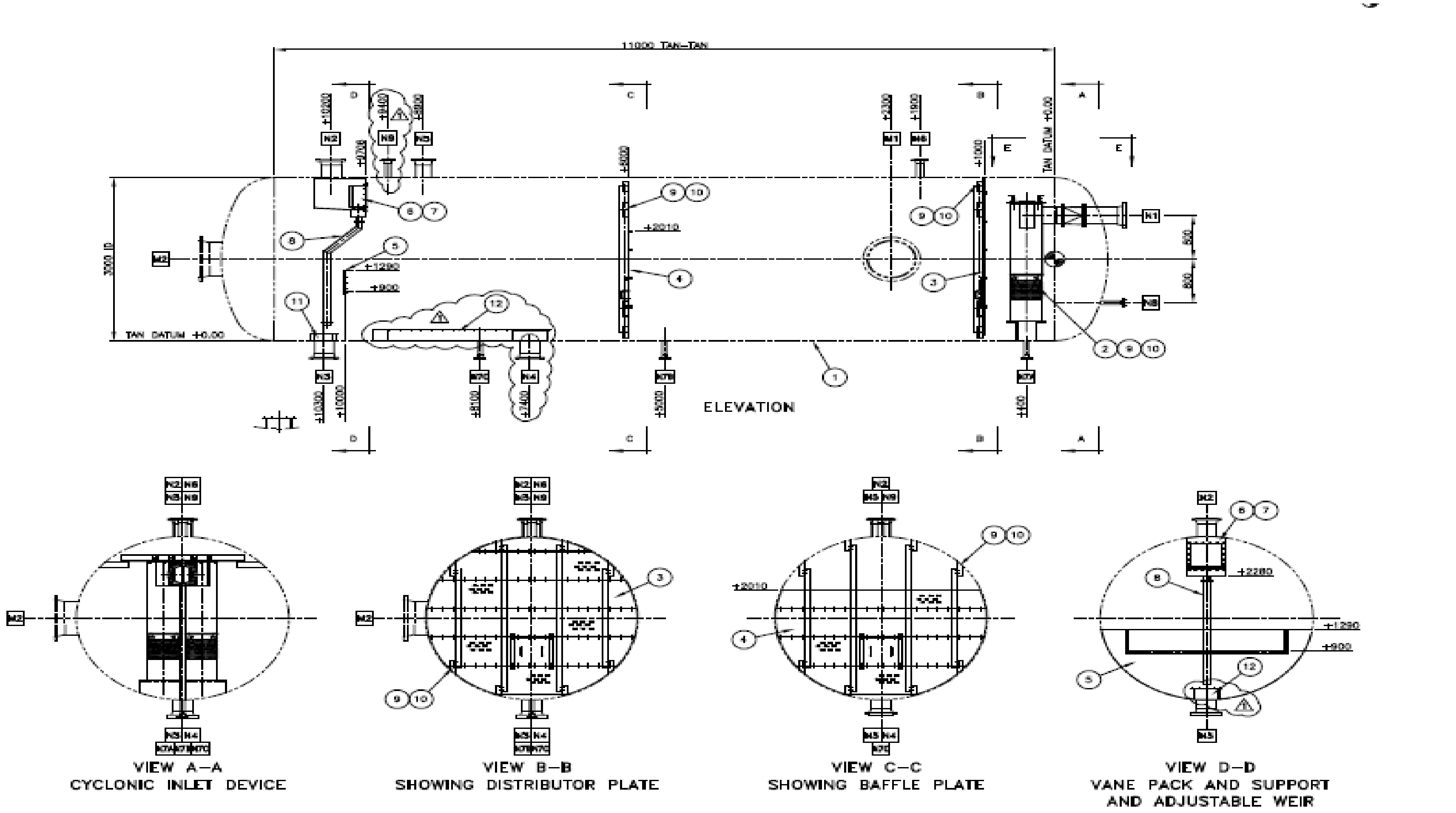
11 Separator P&ID and General Arrangement

Separator P&IDs with key features indicated follow.

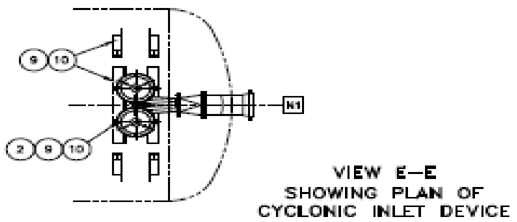

V-21101
HP SEPARATOR
TRAIN 1
Oil Water Interface
Controller
Pressure Controller
Oil Level Controller
Water in Oil
Measurement
V-21101



V-21101
HP SEPARATOR
TRAIN 1
Relief Valve
Inlet Device
Blowdown Valve
V-21101
Weir
Water in Oil
Measurement
Sand
Jetting
Emergency
Shutdown Valves



	CASE 1	CASE 2
HHLL	2000	2000
HLL	1800	1900
NLL	1300	1400
LLL	1150	1300
LLLL	1000	1000
WEIR	900	1290
HIL	725	1100
NIL	625	900
LIL	500	625
LLIL	375	390



Nozzle	Qty	Size	Rating	Face	Service	Remarks
M2	1	24"	300#	RFWN	MANWAY	584.2mm ID
M1	1	24"	300#	RFWN	MANWAY	584.2mm ID
N9	10	3"	300#	RFWN	VENT/COMMISSIONING NOZZLE	
N8	1	2"	300#	RFWN	PURGE	
N7A–C	10	2"	300#	RFWN	DRAIN	
N6	1	4"	300#	RFWN	BLOWDOWN	
N5	1	8"	300#	RFWN	RELIEF	
N4	1	10"	300#	RFWN	WATER OUTLET	C/W VORTEX BREAKER
N3	1	10"	300#	RFWN	OIL OUTLET	C/W VORTEX BREAKER
N2	1	10"	300#	RFWN	GAS OUTLET	
N1	1	12"	300#	RFWN	FLUID INLET	C/W CYCLONIC INLET DEVICE

NOZZLE SCHEDULE (PROCESS RELATED NOZZLES ONLY)

12 Key Learnings

- Key specifications – vapour pressure, water and salt
- Mass balance and hydrocarbon vapour liquid splits
- Emulsion characteristics and bottle tests
- Gravity separation four key functions
- Residence time and internals to improve separator operation
- Application and limitations of Stokes Law
- Horizontal and Vertical Separators
- Entrainment control
- Effect of motion
- Electrostatics
- Chemicals to aid separation process

13 References

Oilfield Processing: Crude Oil : Vol 2 (Oilfield Processing of Petroleum), Francis S. Manning and Richard E. Thompson