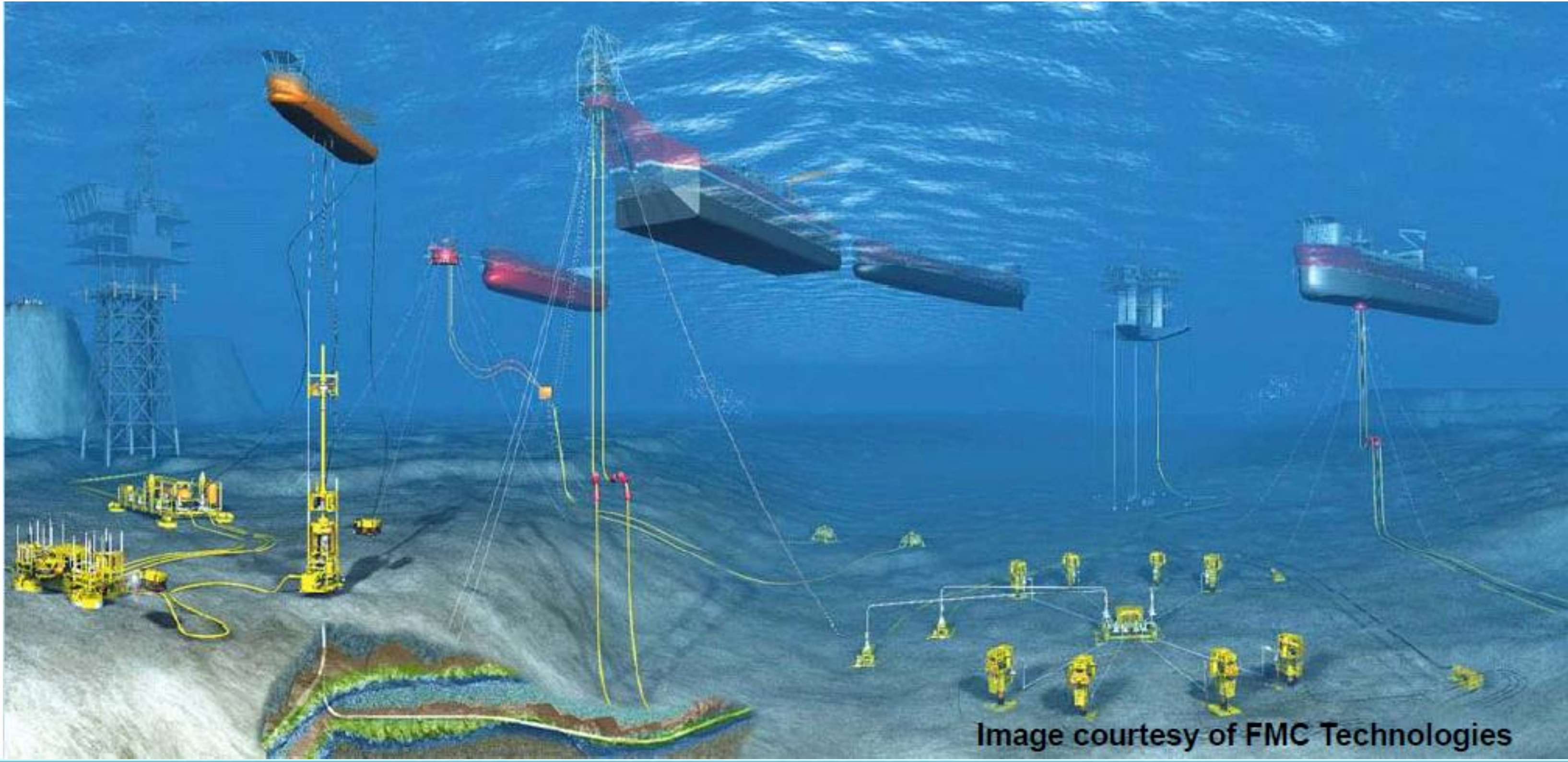


Subsea Engineering

Yutaek Seo

Inlet receiving

- Gas and liquids that enter the gas processing facilities pass emergency shutdown valves, and then go to inlet receiving, where condensed phases drop out. Gas from inlet receiving goes to inlet compression if necessary, and the liquids go to storage for further processing.

- Separator principles

: Effective phase separators protect downstream equipment designed to process a single phase. It is the critical first step in most processes in gas plants and typically is a simple vessel with internal components to enhance separation.

Two-phase oil and gas separation

Introduction

- The velocity of the gas carries liquid droplets, and the liquid carries gas bubbles. The physical separation of these phases is one of the basic operations in the production, processing, and treatment of oil and gas.
- In oil and gas separator design, we mechanically separate the liquid and gas components from a hydrocarbon stream that exist at a specific temperature and pressure. Proper separator design is important because a separation vessel is normally the initial processing vessel in any facility, and improper design of this process can "bottleneck" and reduce the capacity of the entire facility.
- Downstream equipment cannot handle gas-liquid mixtures. For example, pumps require gas-free liquid, to avoid cavitation, while compressors and dehydration equipment require liquid-free gas.
- In addition, measurement devices for gases or liquids are highly inaccurate when another phase is present.
- Two phase: Separate gas from the total liquid stream
- Three phase: also separate the liquid stream into crude oil and water
- Gas scrubber: the ratio of gas rate to liquid rate is very high (mostly gas)
- Slug catcher: two-phase separator to handle intermittent large liquid slug

Functional section of a Gas-Liquid separator

- Inlet Diverter Section

  : abruptly changes the direction of flow by absorbing the momentum of the liquid and allowing the liquid and gas to separate.

- Liquid Collection Section

  : provides the required retention time necessary for any entrained gas in the liquid to escape to the gravity settling section. Also, provides surge volume.

  : The degree of separation is dependent on the retention time provided. Retention time is affected by the amount of liquid the separator can hold, the rate at which the fluids enter the vessel, and the differential density of the fluids.

- Gravity Settling Section

  : Gas velocity drops and small liquid droplets entrained in the gas stream and not separated by the inlet diverter are separated out by gravity and fall to the gas-liquid interface. (remove liquid droplets greater than 100~140 micron)

- Mist Extractor Section

  : Colaescing section to gather small droplets less than 100~140 microns.

  : As the gas flows through the coalescing elements, it must make numerous directional changes.

Equipment description

- Horizontal, vertical, spherical, and a variety of other configurations

Horizontal separators

: The liquid collection section provides the retention time required to let entrained gas evolve out of the oil and rise to the vapor space and reach a state of "equilibrium."

: It also provides a surge volume, if necessary, to handle intermittent slugs of liquid.

: The liquid dump valve is regulated by a level controller. The level controller senses changes in liquid level and controls the dump valve accordingly.

: The pressure in the separator is maintained by a pressure controller mounted on the gas outlet. The pressure controller senses changes in the pressure in the separator and sends a signal to either open or close the pressure control valve accordingly.

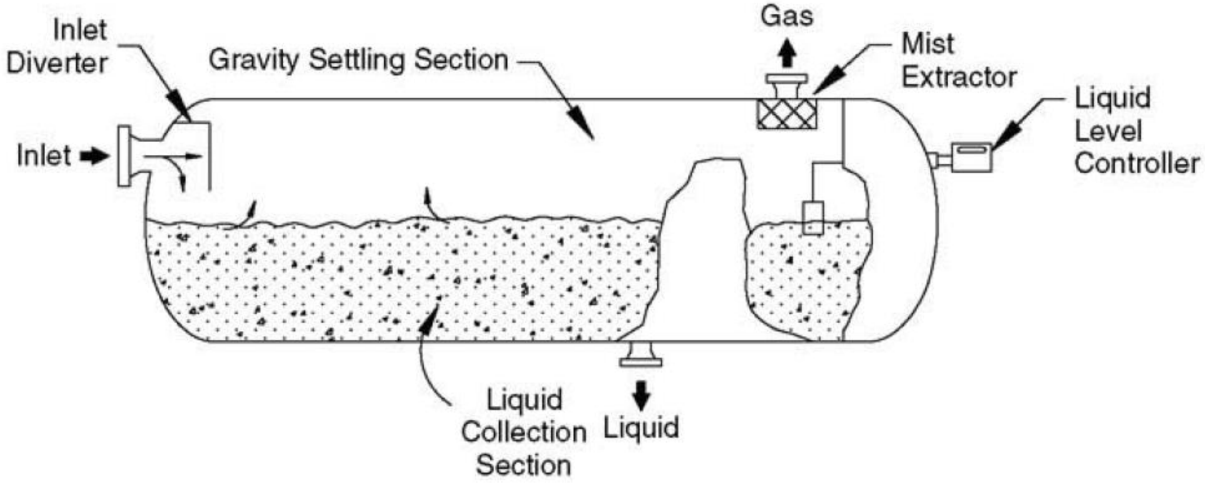


Figure 4-4. Cutaway view of a horizontal two-phase separator.

- Normally, horizontal separators are operated half full of liquid to maximize the surface area of the gas-liquid interface.
- Horizontal separators are smaller and thus less expensive than a vertical separator for a given gas and liquid flow rate. Horizontal separators are commonly used in flow streams with high gas-liquid ratios and foaming crude.

Vertical separators

- The liquid flows down to the liquid collection section of the vessel. The level controller and liquid dump valve operate the same as in a horizontal separator.
- Secondary separation occurs in the upper gravity settling section. In the gravity settling section the liquid droplets fall vertically downward counter-current to the upward gas flow.
- A mist extractor section is added to capture small liquid droplets.
- Pressure and level are maintained as in a horizontal separator.
- Vertical separators are commonly used in flow streams with low to intermediate gas-liquid ratios.
- Suited for sand production

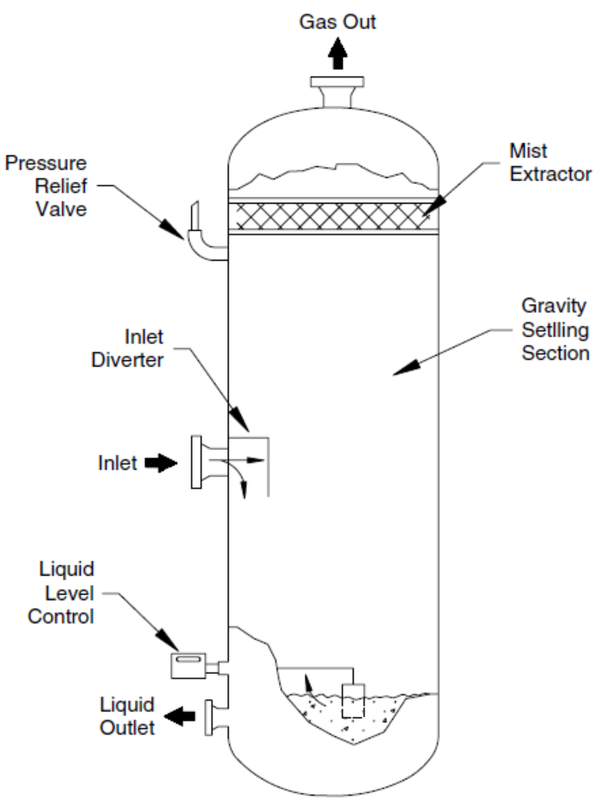


Figure 4-5. Cutaway view of a vertical two-phase separator.

Primary separation

- Primary separation is accomplished by utilizing the difference in momentum between gas and liquid.
- Larger liquid droplets fail to make the sharp turn and impinge on the inlet wall.
- This action coalesces finer droplets so that they drop out quickly.
- Although inlet geometries vary, most separators use this approach to knock out a major portion of the incoming liquid.

Vessel internals

Inlet diverters

- A baffle plate can be a spherical dish, flat plate, angle iron, cone, elbow, or just about anything that will accomplish a rapid change in direction and velocity of the fluids and thus disengage the gas and liquid.
- The advantage of using devices such as a half-sphere elbow or cone is that they create less disturbance than plates or angle iron, cutting down on re-entrainment or emulsifying problems.
- Centrifugal inlet diverters use centrifugal force, but the design is rate sensitive. At low velocities it will not work properly

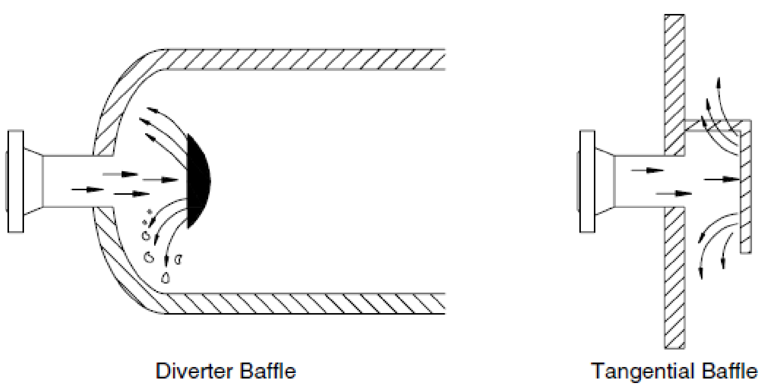


Figure 4-15. Baffle plates.

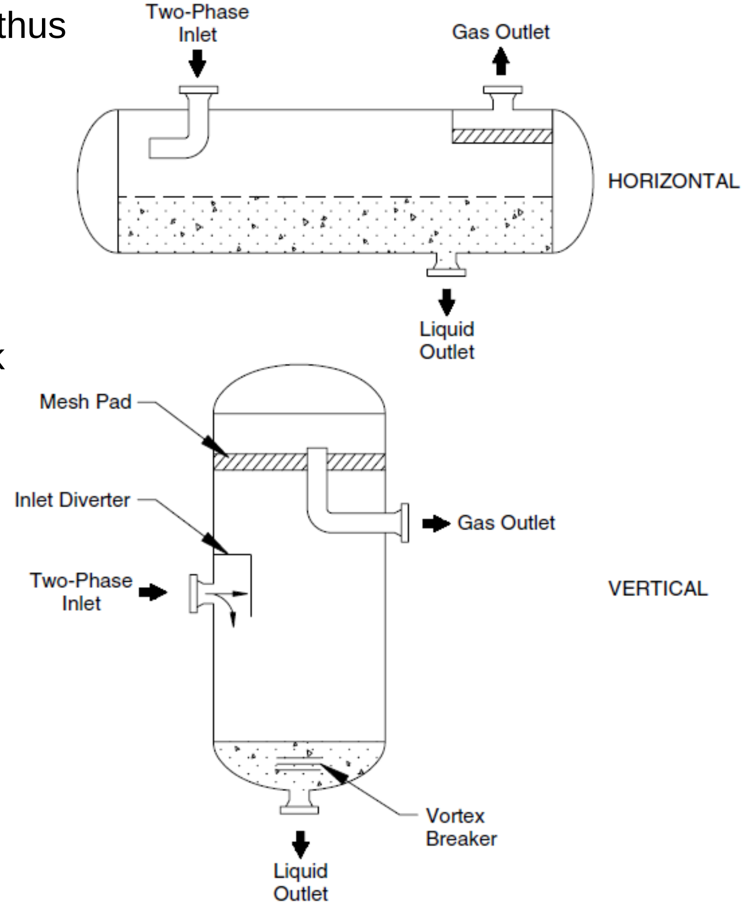


Figure 4-17. Elbow inlet diverter.

Defoaming plates

- Foam at the interface may occur when gas bubbles are liberated from the liquid. This can be stabilized with the addition of chemicals.
- Or force the foam to pass through a series of inclined parallel plates or tubes. These plates or tubes provide additional surface area, which allows the foam to collapse into liquid layer.

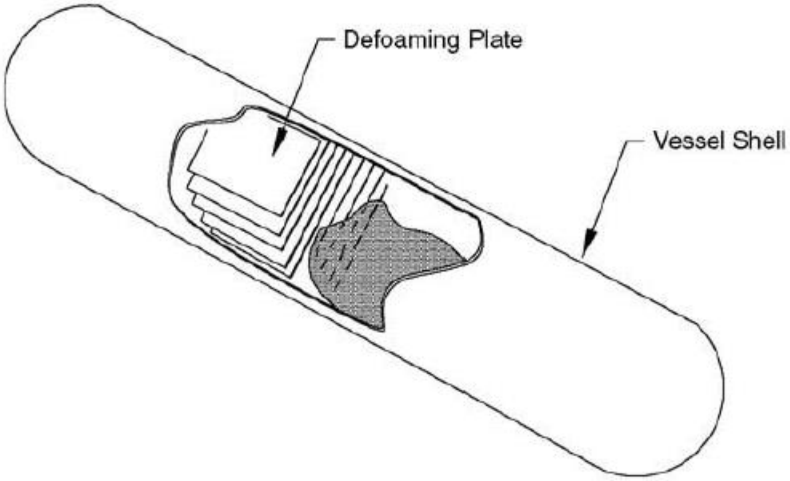


Figure 4-20. Defoaming plates.

Gravity settling

- Gravity settling requires low gas velocities with minimal turbulence to permit droplet fallout.
- The terminal-settling velocity, V_T, for a sphere falling through a stagnant fluid is governed by particle diameter, density differences, gas viscosity, and a drag coefficient that is a function of both droplet shape and Reynolds number.
- the Reynolds number is defined as

$$N_{\mathrm{Re}} = D_P V_T \rho_g / \mu_g, \tag{3.4}$$

where D_p is particle diameter, ρ_g is the density, and μ_g is the viscosity.

- Thus, calculations for V_T are an iterative process.

Liquid collection

- The liquid collection section acts as a holder for the liquids removed from the gas in the above three separation sections.
- This section also provides for degassing of the liquid and for water and solids separation from the hydrocarbon phase.
- The most common solid is iron sulfide from corrosion, which can interfere with the liquid-liquid separation. If a large amount of water is present, separators often have a “boot,” as shown in the horizontal separator, at the bottom of the separator for the water to collect.
- The Engineering Data Book (2004) estimates that retention times of 3 to 5 minutes are required for hydrocarbon-water separation by settling.

Residence time for separator applications

- The residence time is simply the volume of the phase present in the vessel divided by the volumetric flow rate of the phase.
- Table 3.3 provides typical retention times for common gas-liquid separations

TABLE 3.3
Typical Retention Times for Gas-Liquid Separations

Type of Separation	Retention Time (Minutes)
Natural gas condensate separation	2 – 4
Fractionator feed tank	10 – 15
Reflux accumulator	5 – 10
Fractionation column sump	2[a]
Amine flash tank	5 – 10
Refrigeration surge tank	5
Refrigeration economizer	3
Heat medium oil surge tank	5 – 10[b]

[a] If the fractionator column sump is feeding a downstream fractionator column, it should be sized as a feed tank (McCartney, 2005).
[b] This vessel must have adequate space to allow for expansion of the heat medium from ambient to operating temperature (McCartney, 2005).

Source: Engineering Data Book (2004b).

Wave breakers

- Wave breakers are nothing more than perforated baffles or plates that are placed perpendicular to the flow located in the liquid collection section of the separator.
- On floating or compliant structures where internal waves may be set up by the motion of the foundation, wave breakers may also be required perpendicular to the flow direction.

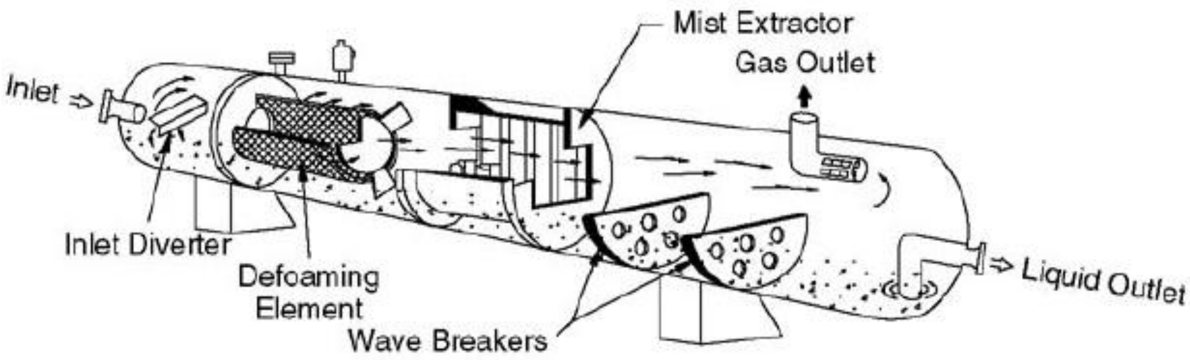


Figure 4-19. Three-dimensional view of a horizontal separator fitted with an inlet diverter, defoaming element, mist extractor, and wave breaker.

Vortex breaker

- Horizontal separators are often equipped with vortex breakers, which prevent a vortex from developing when the liquid control valve is open.
- A vortex could suck some gas out of the vapor space and re-entrain it in the liquid outlet. Any circular motion is prevented by the flat plates.

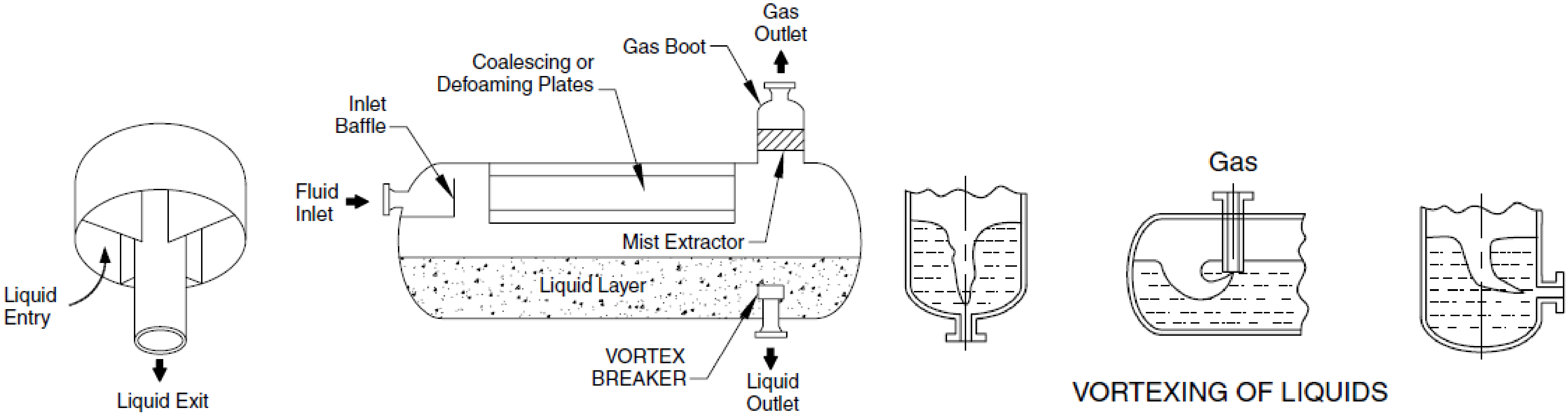


Figure 4-21. Vortex breaker.

Stilling well

- simply a slotted pipe fitting surrounding an internal level control displacer, protects the displacer from currents, waves, and other disturbances

Sand jets and drains

- To remove the solids, sand drains are opened in a controlled manner, and then high-pressure fluid, usually produced water, is pumped through the jets to agitate the solids and flush them down the drains. (jet tip velocity: 6 m/s)
- To assure proper solids removal without upsetting the separation process, an integrated system, consisting of a drain and its associated jets, should be installed at intervals not exceeding 5 ft (1.5 m).

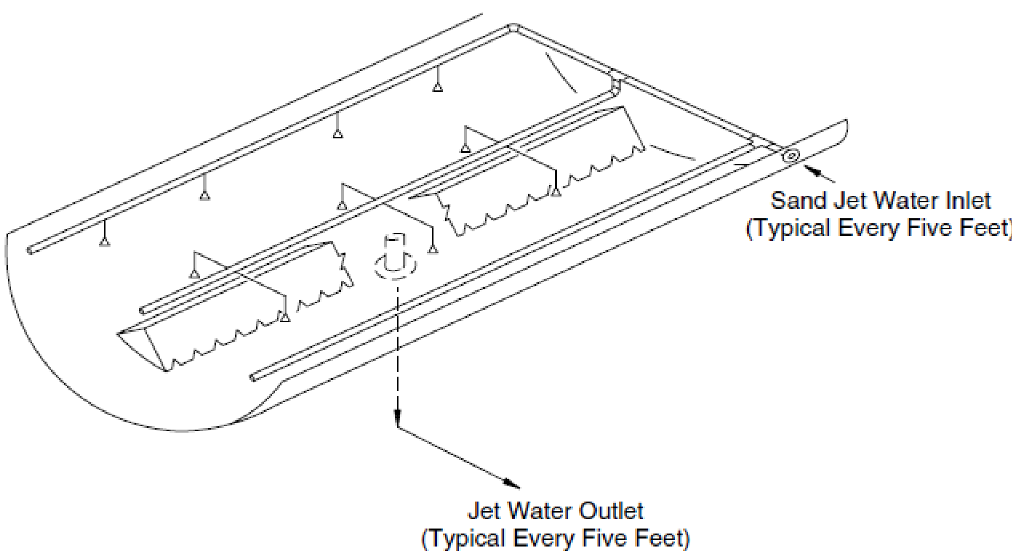


Figure 4-23. Schematic of a horizontal separator fitted with sand jets and inverted trough.

Coalescing

Mist extractors

- Before a selection can be made, one must evaluate the following factors:
  : Size of droplets the separator must remove

  : Pressure drop that can be tolerated in achieving the required level of removal

  : Susceptibility of the separator to plugging by solids, if solids are present

  : Liquid handling capability of the separator

  : Whether the mist extractor/eliminator can be installed inside existing equipment, or if it requires a standalone vessel instead

  : Availability of the materials of construction that are comparable with the process

  : Cost of the mist extractor/eliminator itself and required vessels, piping, instrumentation, and utilities
- All mist extractor types are based on the some kind of intervention in the natural balance between gravitational and drag forces
  : Overcoming drag force by reducing the gas velocity (gravity separators or settling chambers)

  : Introducing additional forces (venturi scrubbers, cyclones, electrostatic precipitators)

  : Increasing gravitational force by boosting the droplet size (impingement-type)

- Baffles

  : consists of a series of baffles, vanes, or plates between which the gas must flow.

  : The surface of the plates serves as a target for droplet impingement and collection. The space between the baffles ranges from 5 to 75 mm, with a total depth in the flow direction of 150 to 300 mm.

  : As gas flows through the plates, droplets impinge on the plate surface. The droplets coalesce, fall, and are routed to the liquid collection section of the vessel.

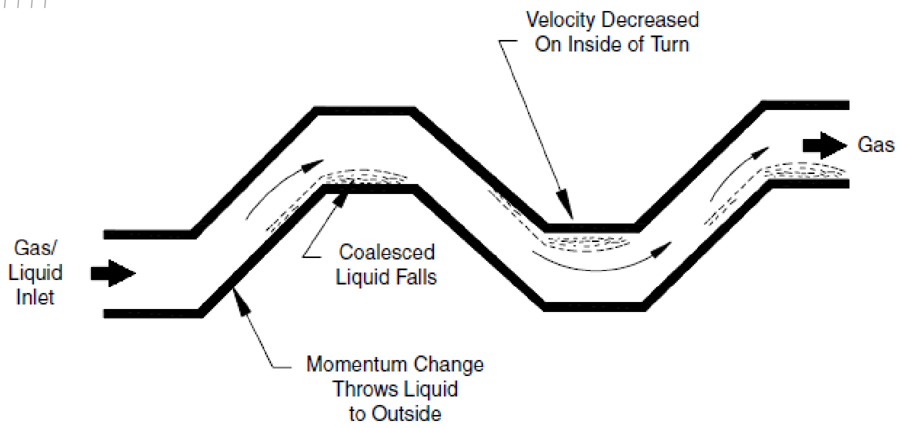


Figure 4-25. Typical vane-type mist extractor/eliminator.

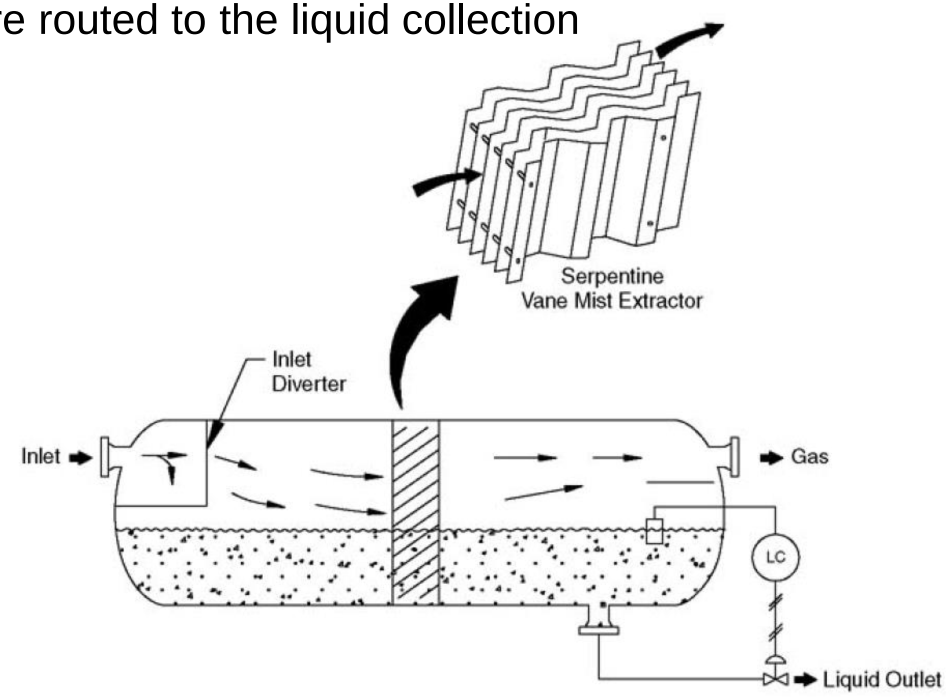


Figure 4-28. Cutaway view of a horizontal separator fitted with a vane-type mist extractor.

- Wire-mesh

  : The most common type of mist extractor found in production operations is the knitted-wire-mesh type

  : have high surface area and void volume.

  : The wire pad is placed between top and bottom support grids to complete the assembly.

  : The effectiveness of wire-mesh depends largely on the gas being in the proper velocity range

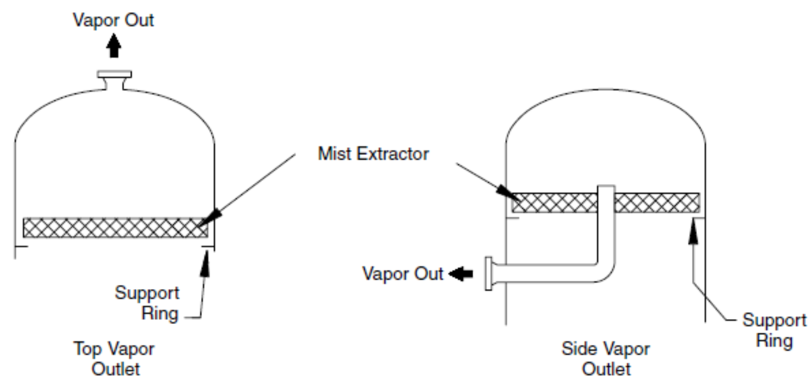


Figure 4-32. Vertical separators fitted with wire-mesh pads supported by support rings.

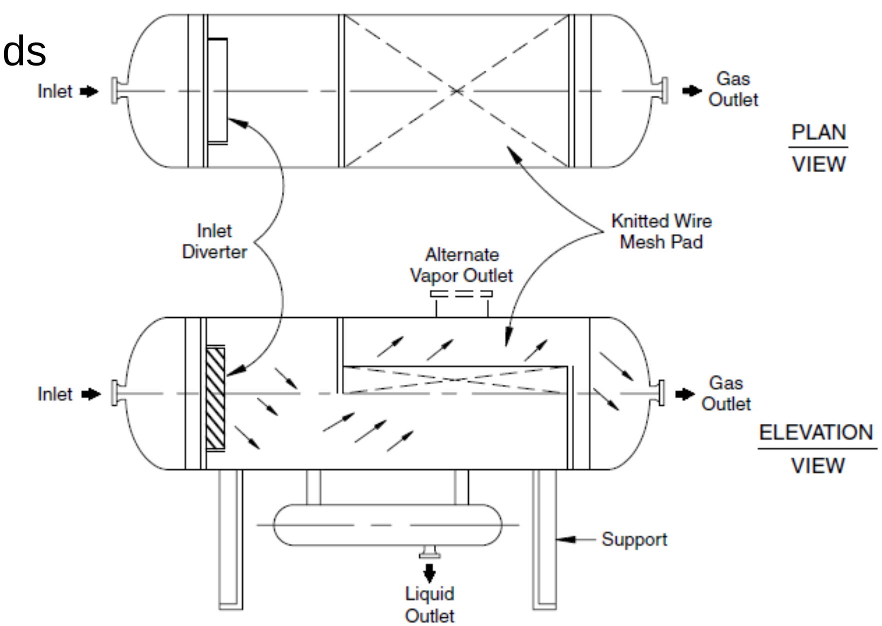


Figure 4-33. Horizontal separator fitted with wire-mesh pads supported by a frame.

Figure 4-31. Example wire-mesh mist extractor. (Photo courtesy of ACS Industries, LP, Houston, Texas.)

- A properly sized wire-mesh unit can remove 100% of liquid droplets larger than 3 to 10 microns in diameter. Although wire-mesh eliminators are inexpensive, they are more easily plugged than the other types. Wire-mesh pads are not the best choice if solids can accumulate and plug the pad.

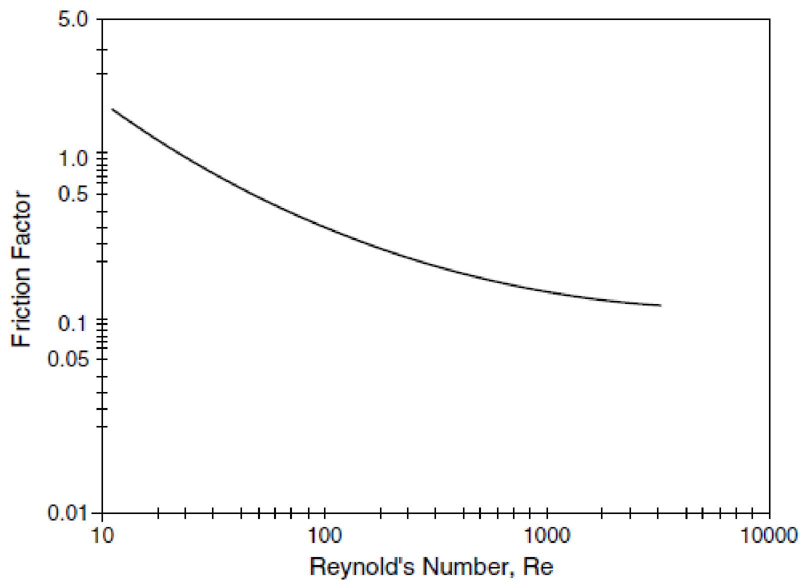


Figure 4-34. Friction factor versus Reynolds number for a dry knitted wire-mesh extractor.

- Micro-fiber

  : Use very small diameter fibers, usually less than 0.02 mm, to capture very small droplets.

  : Much of the liquid is eventually pushed through the micro-fiber and drains on the downstream face. The surface area of a micro-fiber mist extractor can be 3 to 150 times that of a wire-mesh unit of equal volume.

  : There are two categories of these units, depending on whether droplet capture is via inertial impaction (interception), or Brownian diffusion. Only the diffusion type can remove droplets less than 2 microns.

Table 4-1
Features of Impingement-Type Mist Extractors

Consideration	Wire-Mesh	Vane	Micro-fiber
Cost	Lowest	2–3 times wire-mesh unit	Highest
Efficiency	100% (for droplets larger than 3–10 μ	100% (for mists > 20–40 μ)	Up to 99.9% (for mists < 3 μ)
Pressure drop	< 25 mm H_2O	< 15 mm H_2O	100–300 mm
Gas capacity	Very good	Up to twice that of a wire-mesh unit	Lowest
Liquid capacity	Good	Best	Lowest
Solids	Good	Best	Soluble particles with sprays only

- Final selection

  : Wire-mesh pads are the cheapest, but mesh pads are the most susceptible to plugging with paraffins, gas hydrates, etc. With age, mesh pads also tend to deteriorate and release wires and/or chunks of the pad into the gas stream.

  : Vane units are more expensive. Typically, vane units are less susceptible to plugging and deterioration than mesh pads.

  : Micro-fiber units are the most expensive and are capable of capturing very small droplets but, like wire mesh pads, are susceptible to plugging.

  : The selection of a type of mist extractor is affected by the fluid characteristics, the system requirements, and the cost.

  * It is recommended that the sizing of mist extractors should be left to the manufacturer.

- Figure 3.13 shows qualitatively the range for mist pads and vane packs. The data are based upon an air-water system and differs from natural gas data because of density and surface tension.

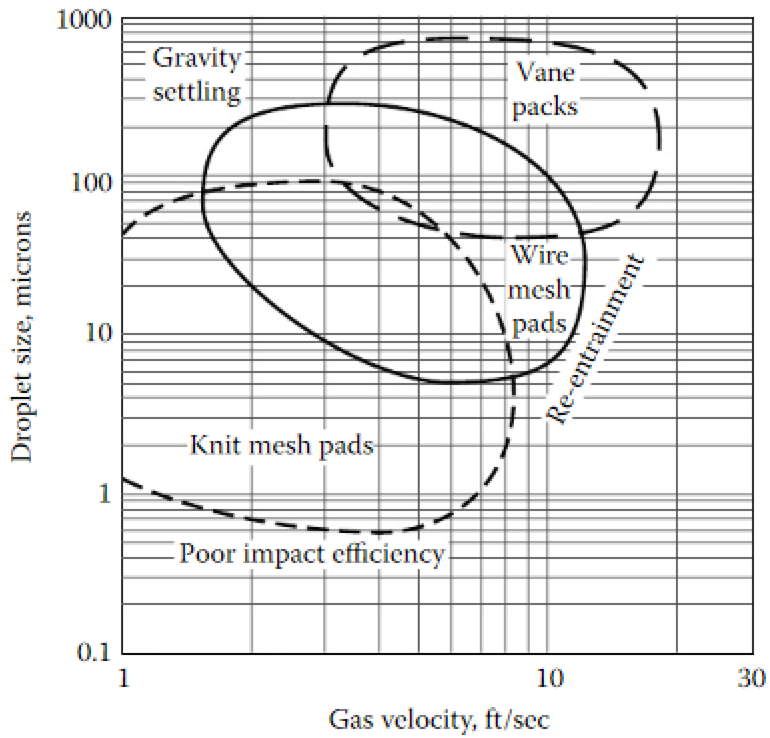


FIGURE 3.13 Approximate operating ranges for different kinds of demisters. Data are based upon water and air. (Courtesy of ACS Industries, 2005.)

- Figure 3.13 shows the regions where each demister type is effective.
- Note that these devices fail to coalesce droplets below around 0.5 micron, and each has both upper and lower velocity limits.
- The lower limit is caused by too low a velocity to force sufficient impinging of the droplets on the solid surface to provide coalescing. At high velocities, the coalesced droplets are stripped from the solid by the high velocity gas.
- The Engineering Data Book (2004) and Bacon (2001) provide design calculations for wire mesh and vane pack coalescing units.

1. Engineering Data Book, 12th ed., Sec. 7, Separation Equipment, Gas Processors Supply Association, Tulsa, OK, 2004.
2. Bacon, T.R, Fundamentals of Separation of Gases, Liquids, and Solids, Proceedings of the Laurance Reid Gas Conditioning Conference, Norman, OK, 2001.

Slugging during ramp up and pigging

- Ramp Up:

  : Total Liquids Produced

  = holdup at the lower flowrate (minus) holdup at the higher rate.

  : The actual liquid production rate during this period will depend on the fluids, the flowline design and the flow conditions.

- Pigging: The greatest effects on liquid production during pigging occur with gas condensate flowlines. The entire flowline liquid holdup (except for the pig by-pass volume) will be produced in front of the pig.

Slug catcher configurations

- This section briefly describes two kinds of slug catchers, manifolded piping and inlet vessels.
- The most difficult part of a slug catcher design is the proper sizing. Sizing requires knowledge of the largest expected liquid slug, as liquid pump discharge capacity on the slug catcher will be trivial compared with the sudden liquid influx.
- Manifolded Piping

  : One reason piping is used instead of separators is to minimize vessel wall thickness. This feature makes piping attractive at pressures above 500 psi (35bar).

  : The simplest slug-catcher design is a single-pipe design that is an increased diameter on the inlet piping. However, this design requires special pigs to accommodate the change in line size.

Slug catcher

: is a special case of a two-phase gas-liquid separator that is designed to handle large gas capacities and liquid slugs on a regular basis.

: When the pigs sweep the liquids out of the gathering lines, large volumes of liquids must be handled by the downstream separation equipment.

: Gas and liquid slug from the gathering system enters the horizontal portion of the two-phase vessel, where primary gas-liquid separation is accomplished.

: Gas exits the top of the separator through the mist extractor while the liquid exits the bottom of the vessel through a series of large-diameter tubes or "fingers."

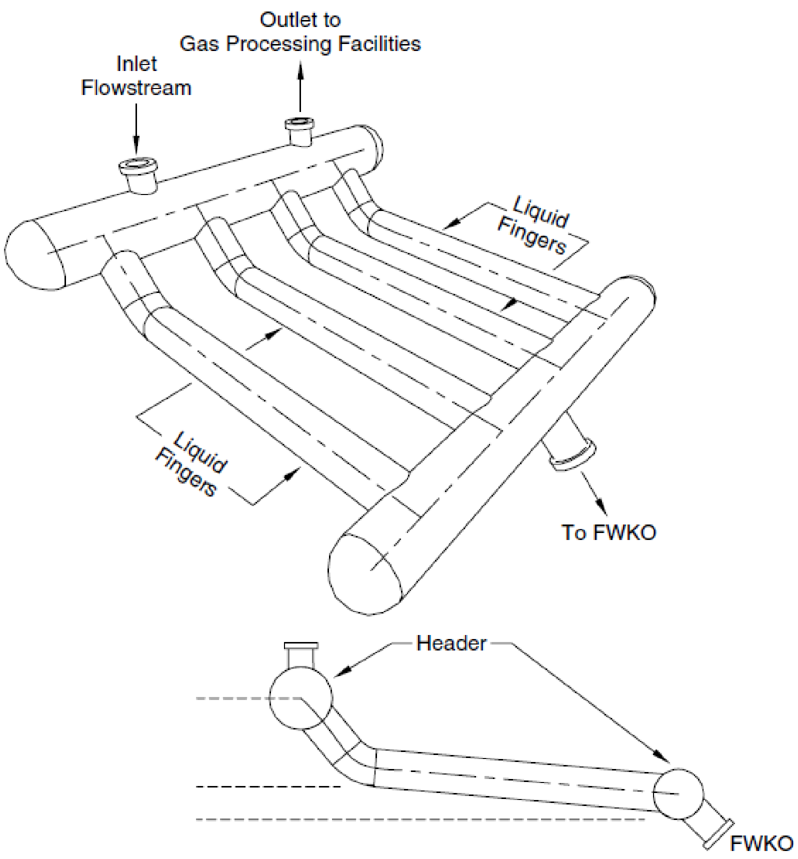


Figure 4-13. Schematic of a two-phase horizontal slug catcher with liquid "fingers."

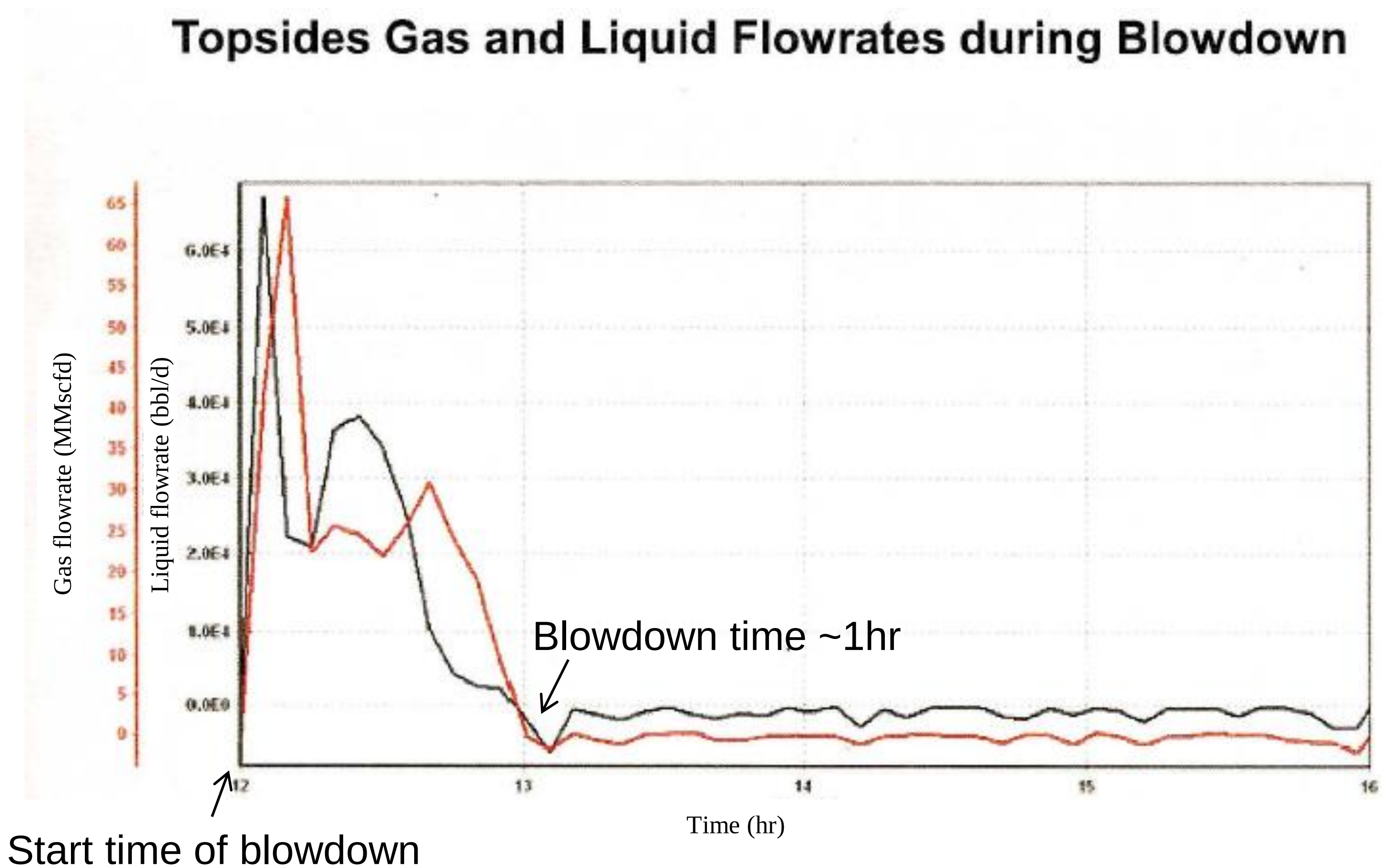
- The number of pipes varies, depending upon the required volume and operating pressure. Also, some designs include a loop line, where some of the incoming gas bypasses the slug catcher.
- Primary separation occurs when the gas makes the turn at the inlet and goes down the pipes. Liquid distribution between pipes can be a problem, and additional lines between the tubes are often used to balance the liquid levels. In harp designs, the pipes are sloped so that the liquid drains toward the outlet.
- Gravity settling occurs as the gas flows to the vapor outlet on the top while the liquid flows out the bottom outlet.
- Pipe diameters are usually relatively small(usually less than 48 inches [120 cm]), so settling distances are short.

- Because manifolded piping is strictly for catching liquid slugs, demisters are usually installed downstream in scrubbers. Likewise, liquid goes to other vessels, where degassing and hydrocarbon-water separation occurs.
- Several advantages to the pipe design include the fact that design specifications are based upon pipe codes instead of vessel codes.
- Also, the slug catcher can be underground, which reduces maintenance costs and insulation costs if the slug catcher would otherwise need to be heated.

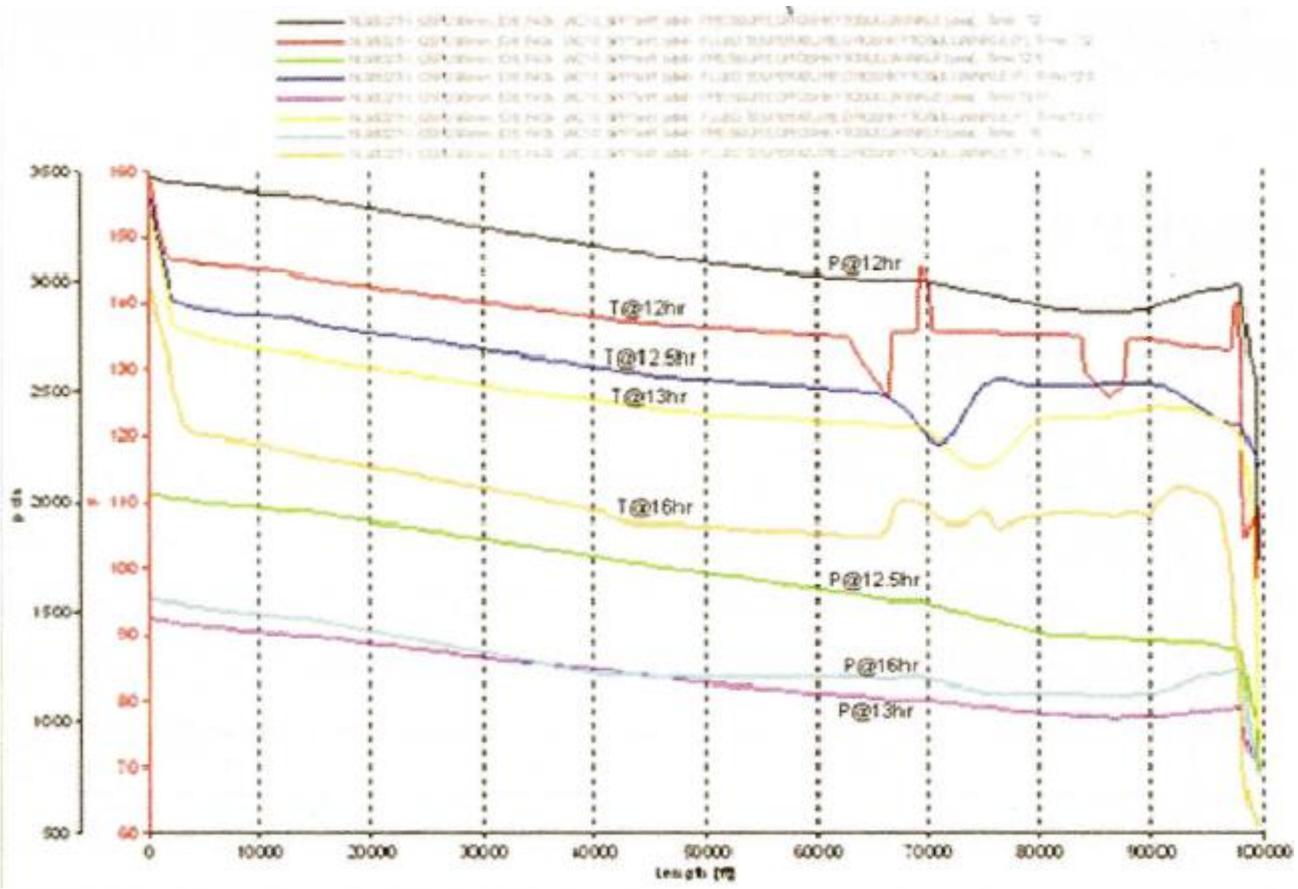
Flowline depressurization or blowdown

- Depressurization generally refers to the relatively slow evacuation of a pipeline system. Blowdown generally refers to the rapid evacuation of a pipeline.
- Depressurizing is usually performed to make the pipeline available for maintenance or repair. Depressurizing a pipeline will usually take quite a few hours or even days.
- Pipeline blowdown will generally take a few hours. Blowdown is sometimes referred to as emergency depressurization. Pipeline blowdown is often used to minimize the potential for hydrate formation during a shutdown and to remove the hydrostatic head rapidly.
- The terms blowdown and depressurization are sometimes used interchangeably

Blowdown fluid rates



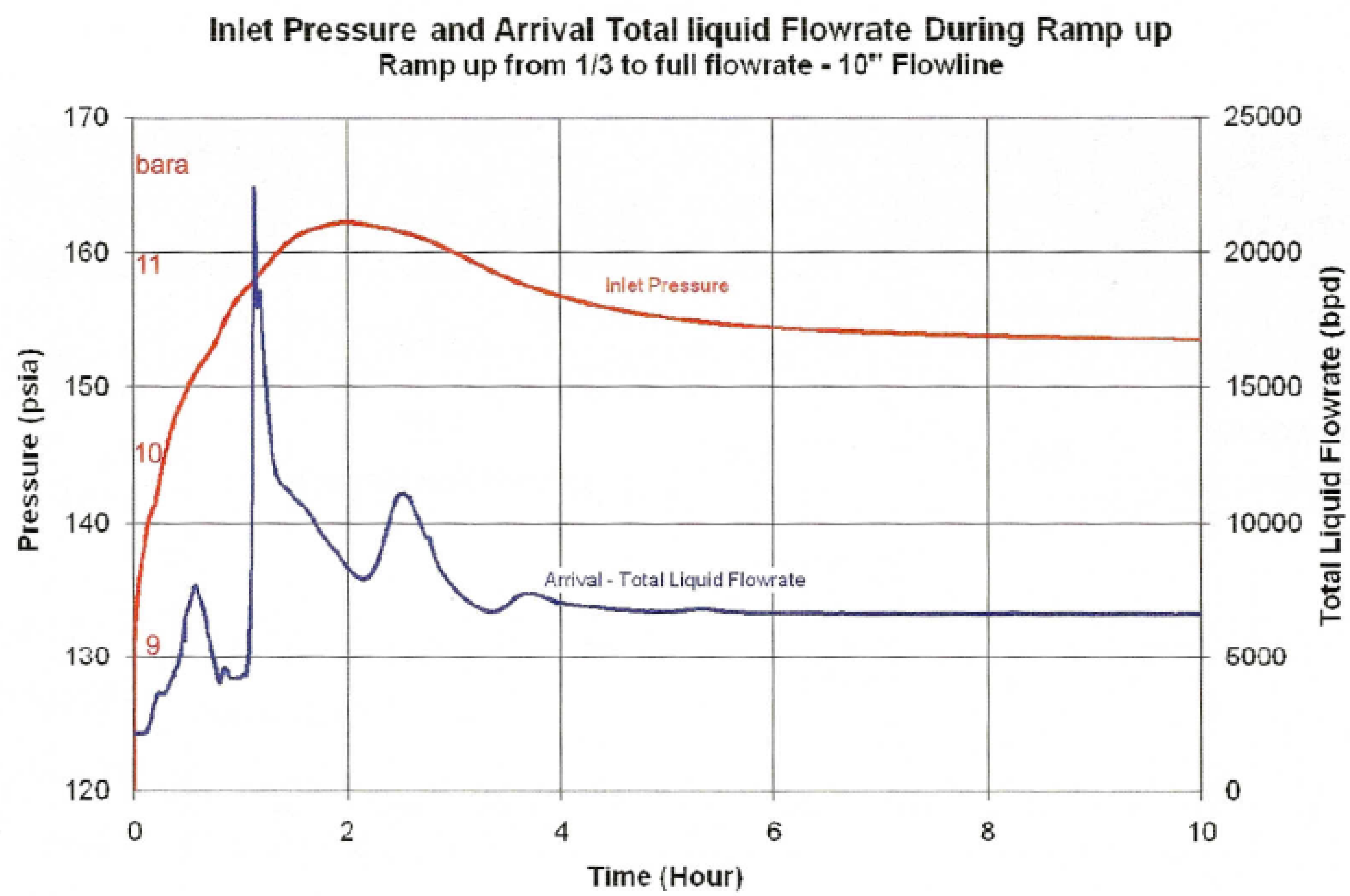
Flowline T & P profiles during blowdown



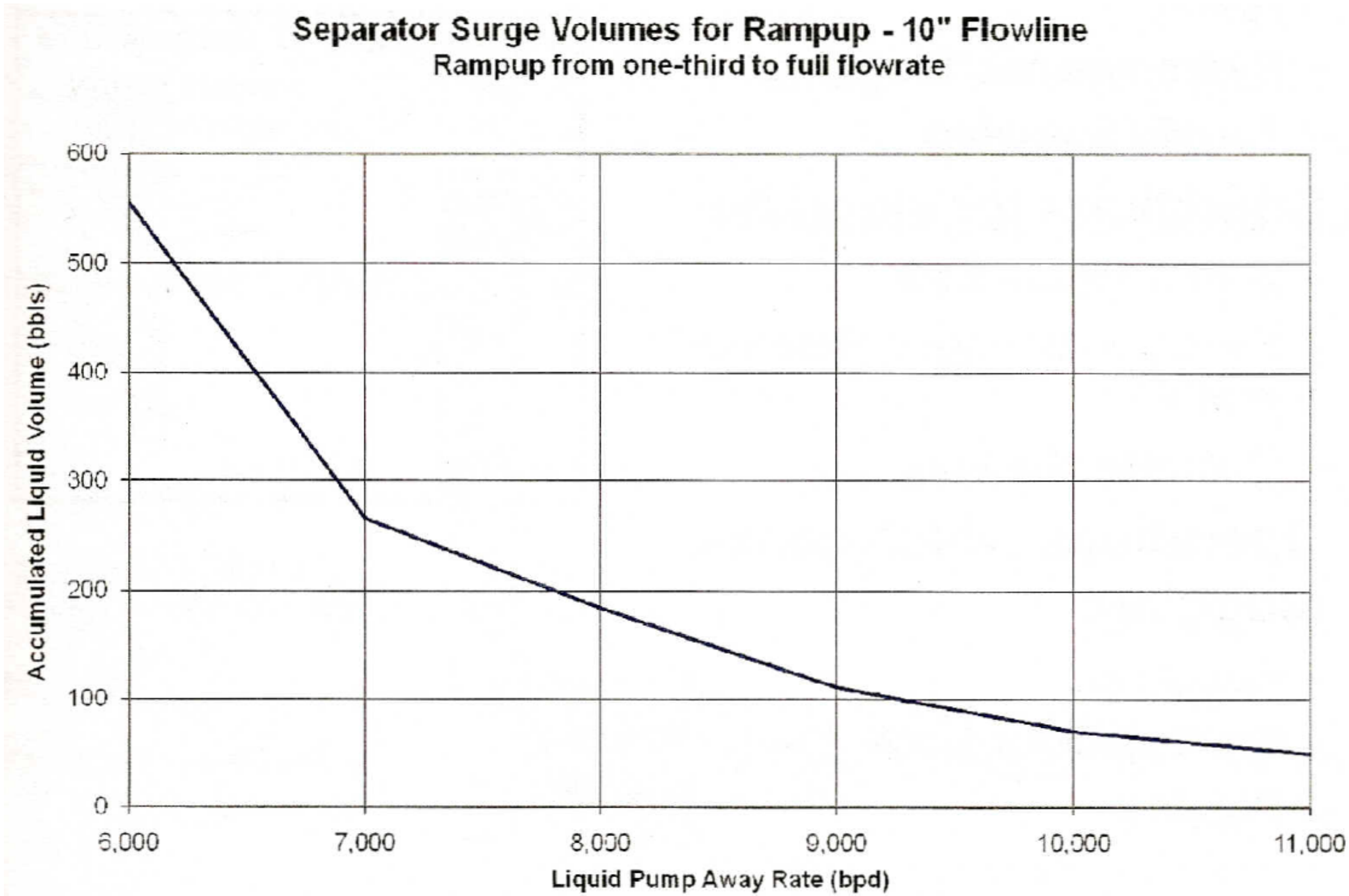
Blowdown results

Scenario	Liquid rate (bpd)	Gas rate (MMscfd)	Flowline highest pressure (psia)	Volume of liquid (bbl)
Normal production	40,000	40	5500	NA
Blowdown Maximums	68,000	66	1600 (after blowdown)	1069

Ramp up flowrates and pressure

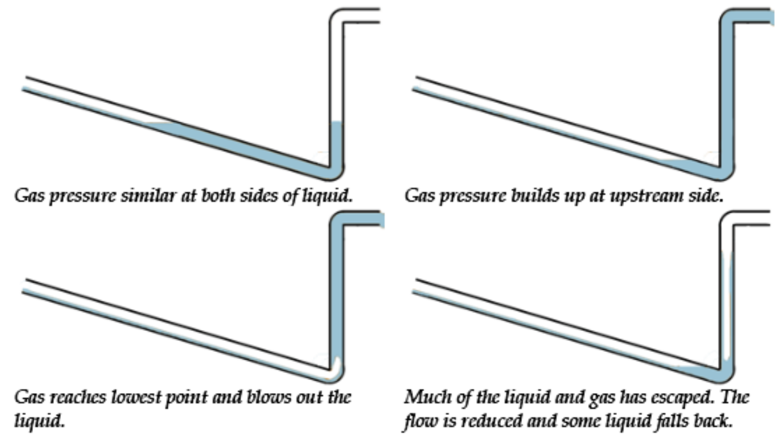


Separator surge volume during ramp up



Slugging

- Types:
  - Hydrodynamic Slugging
  - Terrain Slugging
- Conditions for slugging
  - 2- or 3-Phase flow
  - Elevation changes (seafloor profile)
  - Flowrate changes



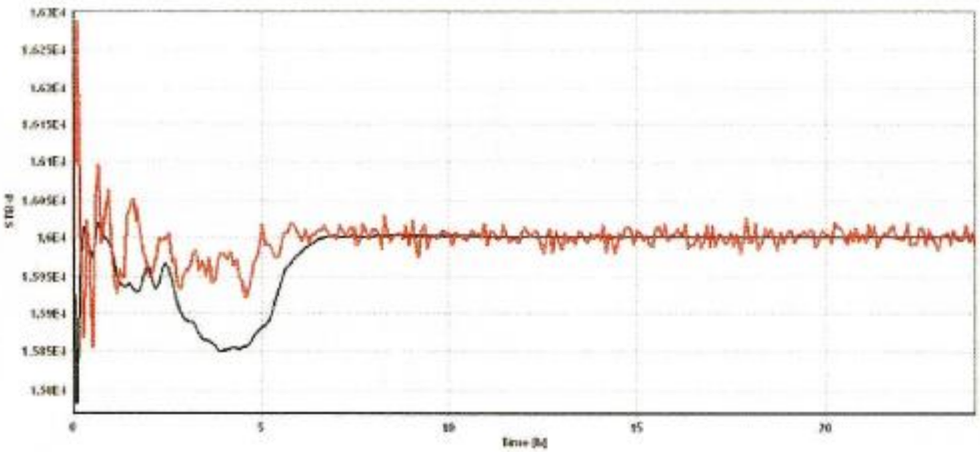
- Operations which cause slugging:
  - Ramp up
  - Start-up/Blowdown
  - Pigging

Caused by Flowrate changes

Moderate flowrate slugging

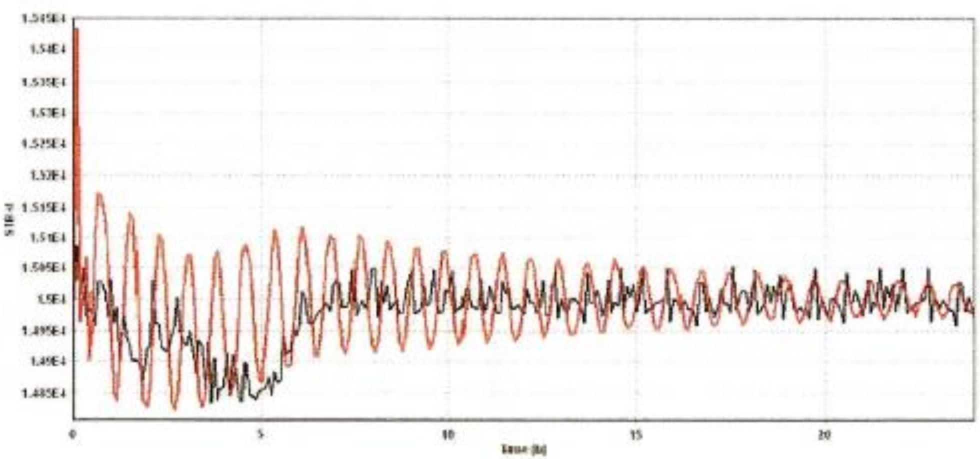
Slugging at 16kbopd
Average production rate
WC = 10%
WC = 80%

Max liquid rate = 16.3kblpd



Slugging at 15kbopd
Average production rate
WC = 10%
WC = 80%

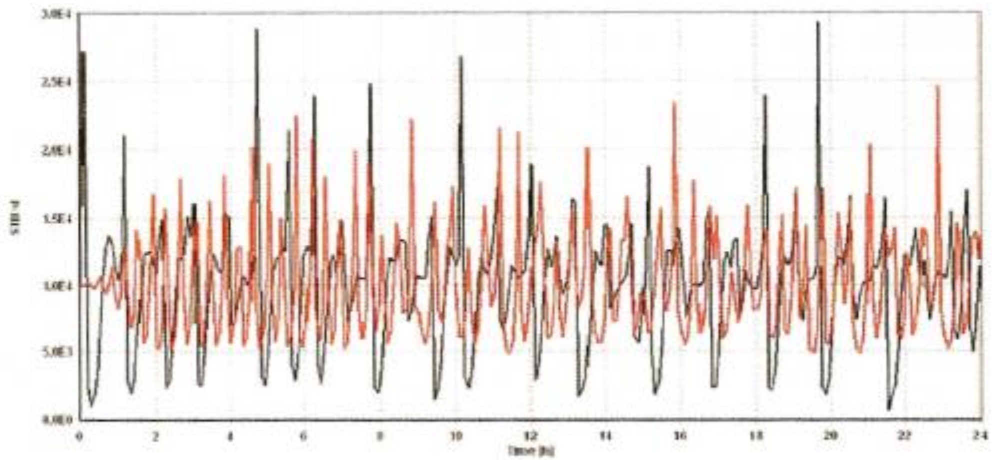
Max liquid rate = 15.4kblpd



Low flowrate slugging

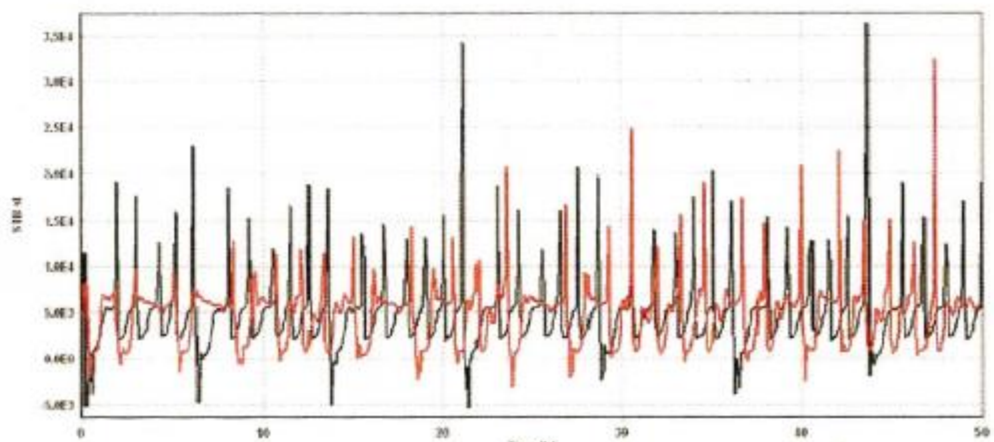
Slugging at 10kbopd
Average production rate
WC = 10%
WC = 80%

Max liquid rate = 29kblpd



Slugging at 5kbopd
Average production rate
WC = 10%
WC = 80%

Max liquid rate = 36kblpd

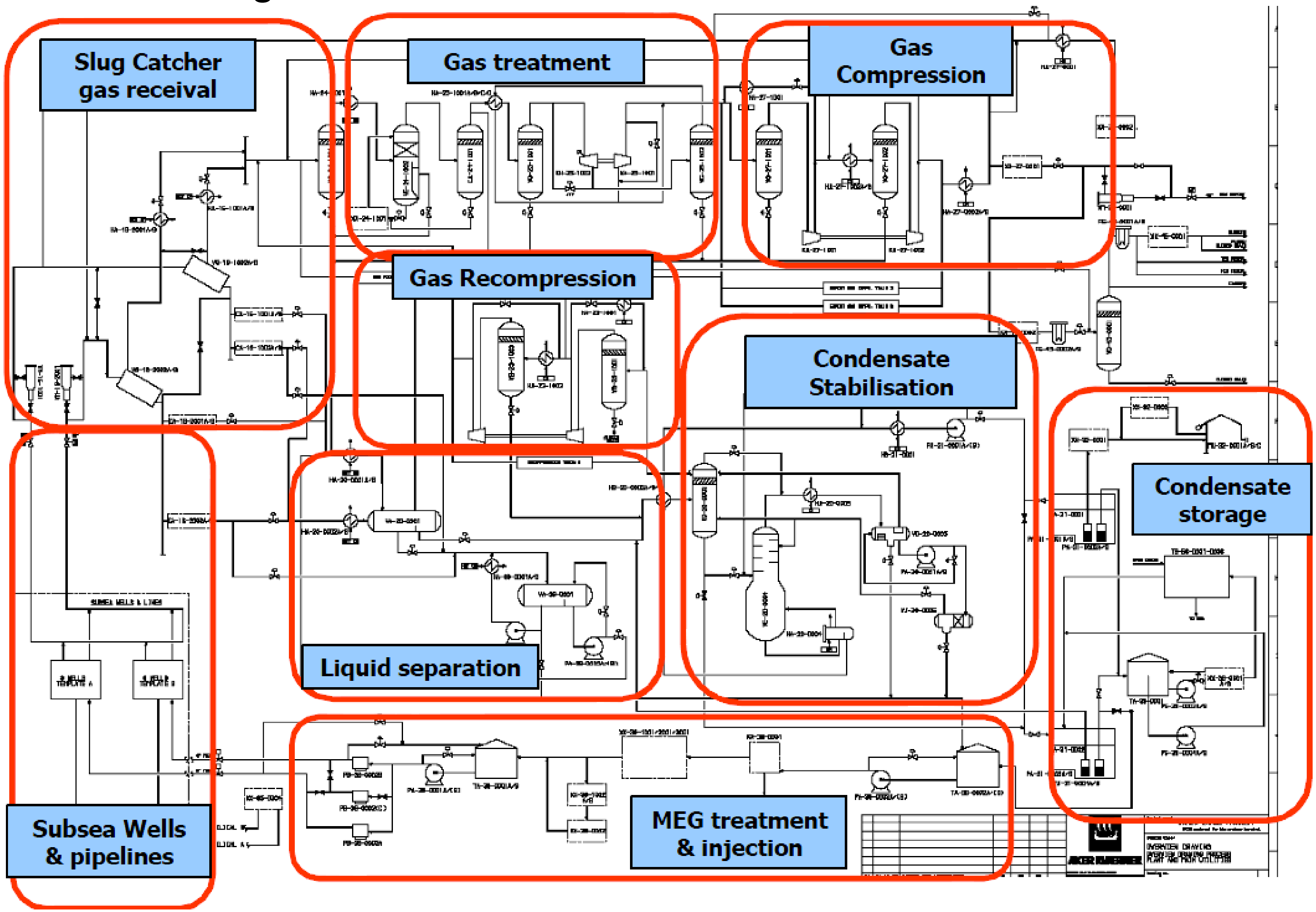


Low flowrate slugging characteristics

Liquid production rate (STB/d)	5,000		10,000	
Water cut (%)	10	80	10	80
Slugging frequency (1/hr)	0.5	0.8	2.2	0.72
Max. slug volume (bbl)	330	279	242	257

Gas condensate flowline slug catcher

- Ormen Lange



2 Slug Catcher units 1500m³ capacity

Can be connected to provide 3000m³ capacity