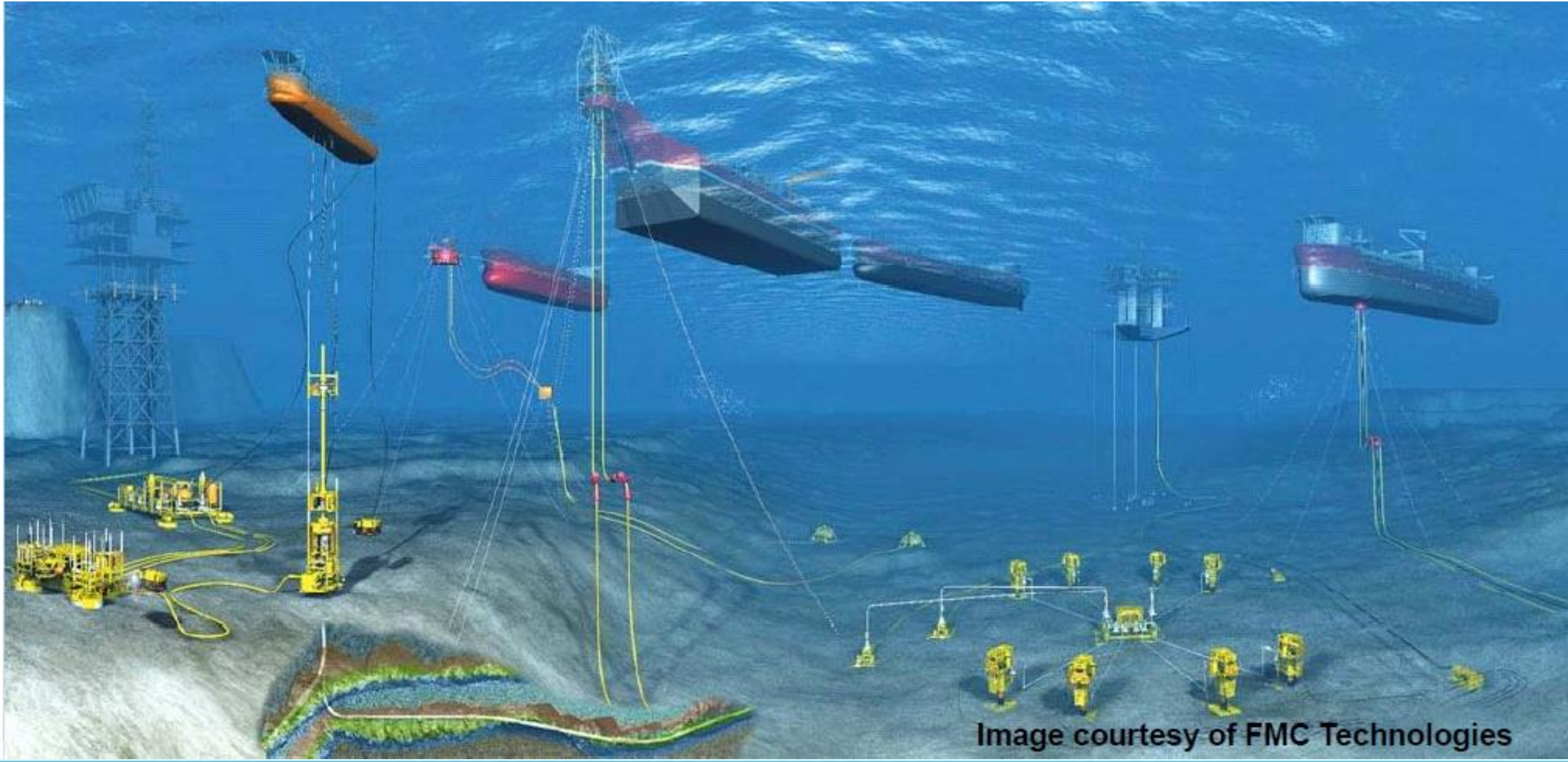


Introduction to Offshore Engineering

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.

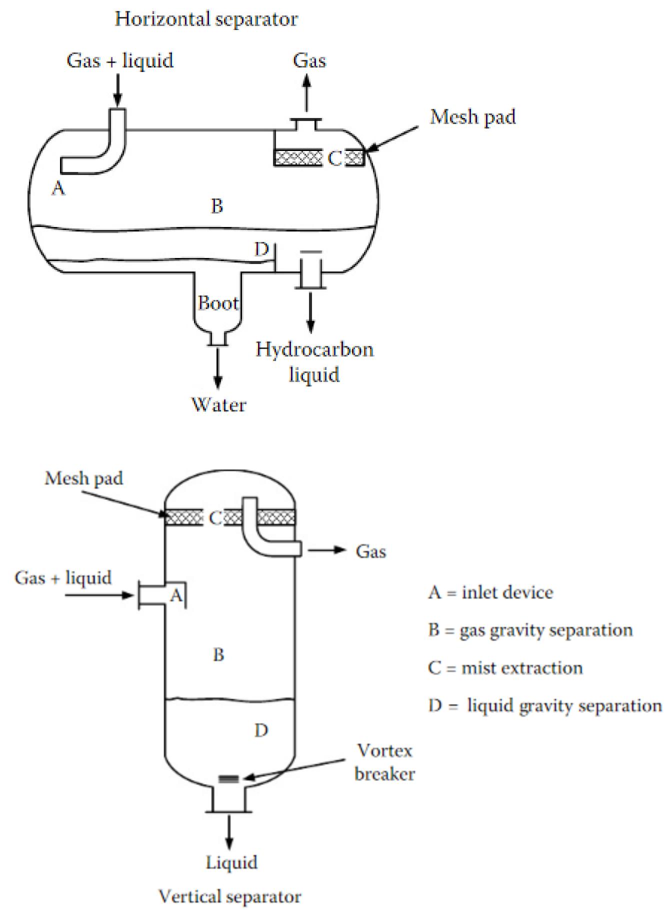
- Separator principles

: 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.

Gas-Liquid separation

- Separator vessel orientation can be vertical or horizontal.
- Vertical separators are most commonly used when the liquid-to-gas ratio is low or gas flow rates are low. They are preferred offshore because they occupy less platform area.
- However, gas flow is upwards and opposes the flow of liquid droplets. Therefore, vertical separators can be bigger and, thus, more costly than horizontal separators. Inlet suction scrubbers at compressor stations are usually vertical.
- Horizontal separators are favored for large liquid volumes or if the liquid-to-gas ratio is high. Lower gas flow rates and increased residence times offer better liquid dropout.
- The larger surface area provides better degassing and more stable liquid levels as well.

- Following figure shows a schematic of gas-liquid separators and indicates the four types of separation:
- Primary separation
- Gravity settling
- Coalescing
- Liquid collecting



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.

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

$$N_{Re} = D_P V_T \rho_g / \mu_g, \qquad (3.4)$$

  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.

- For large particles (1,000 to ~70,000 micron), the terminal velocity is computed by the equation

$$V_T = 1.74\sqrt{\frac{gD_p(\rho_l - \rho_g)}{\rho_g}} \quad , \qquad (3.5)$$

where g is the gravitational constant.

- This equation, known as Newton's law, applies when the Reynolds number is greater than 500.
- If the particle size is too large, excessive turbulence occurs and Eq (3.5) fails. The upper limit is found by use of the equation

$$D_P = K_{CR}\left[\frac{\mu_g^2}{g\rho_g(\rho_l - \rho_g)}\right]^{\frac{1}{3}} \qquad (3.6)$$

With K_{CR} = 18.13 and 23.64 for engineering and metric units, respectively, and is based upon a Reynolds number of 200,000, which is the upper limit for Newton's law to hold.

- At the other extreme, where the flow is laminar (NRe < 2), Stokes' law applies. The terminal velocity is

$$V_T = \frac{1{,}488 g D_p^2 (\rho_g - \rho_l)}{18\mu_g} \qquad (3.7a)$$

$$V_T = \frac{1{,}000 g D_p^2 (\rho_g - \rho_l)}{18\mu_g} \qquad (3.7b)$$

where Eq (3.7a) is in English units and Eq (3.7b) is in SI.

- Stokes' law applies to particles in the 3 to 100 micron range.
- To find the maximum size particle in this flow regime, use K_{CR} = 0.0080 in Eq (3.6), which corresponds to an N_{Re} of 2.
- Particles smaller than 3 microns will not settle because of Brownian motion.

- Unfortunately, droplets that condense from a vapor tend to be in the 0.1 to 10 micronrange; the majority are around 1 micron.
- Entrained droplets are 100 times larger. To reduce turbulence, the settling section may contain vanes. They also act as droplet collectors to reduce the distance droplets must fall.

Coalescing

- The coalescing section contains an insert that forces the gas through a torturous path to bring small mist particles together as they collect on the insert. These inserts can be mesh pads, vane packs, or cyclonic devices.

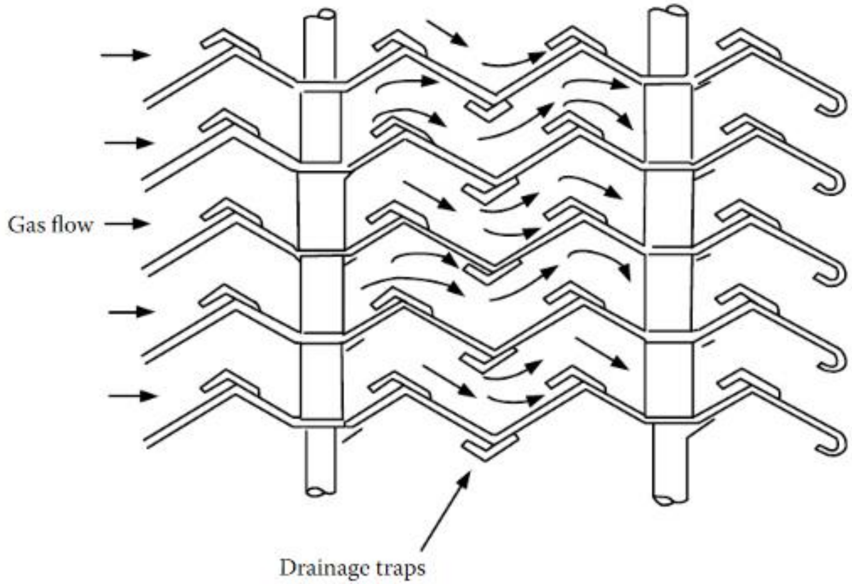
TABLE 3.2
Features of Mist Extracting Devices

	Wire Mesh	Vane Pack
Gas capacity factor, C in Equation 3.8, ft/sec (m/sec)	0.22 – 0.39 (0.067 – 0.12)	Horizontal flow 0.9 – 1.0 (0.27 – 0.30) Vertical flow 0.4 – 0.5 (0.12 – 0.15)
Droplet efficiency	99 – 99.5% removal of 3- to 10-micron droplets	99% removal of 10- to 40-micron droplets
Turndown range, % of design gas rate	30 – 110	Rapid decrease in efficiency with decreased gas flow
Pressure drop, inches of water (kPa)	< 1 (0.25)	0.5 to 3.5 (0.12 to 0.87)

Source: Engineering Data Book (2004b).

- Mesh pads are either wire or knitted mesh, usually about 6 inches (15 cm) thick, and, preferably, are mounted horizontally with upward gas flow, but they can be vertical.
- They loose effectiveness if tilted. Mesh pads tend to be more effective at mist removal than vane packs but are subject to plugging by solids and heavy oils.

- Following figure shows several elements of a vane pack, which are corrugated plates, usually spaced 1 to 1.5 inches (2.4 to 3.8 cm) apart, that force the gas and mist to follow a zigzag pattern to coalesce the mist into larger particles as they hit the plates.



- Coalesced drops collect and flow out the drainage traps in the plates. Although not as effective at removing small drops, they are ideal for “dirty” service because they will not plug.

- 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.

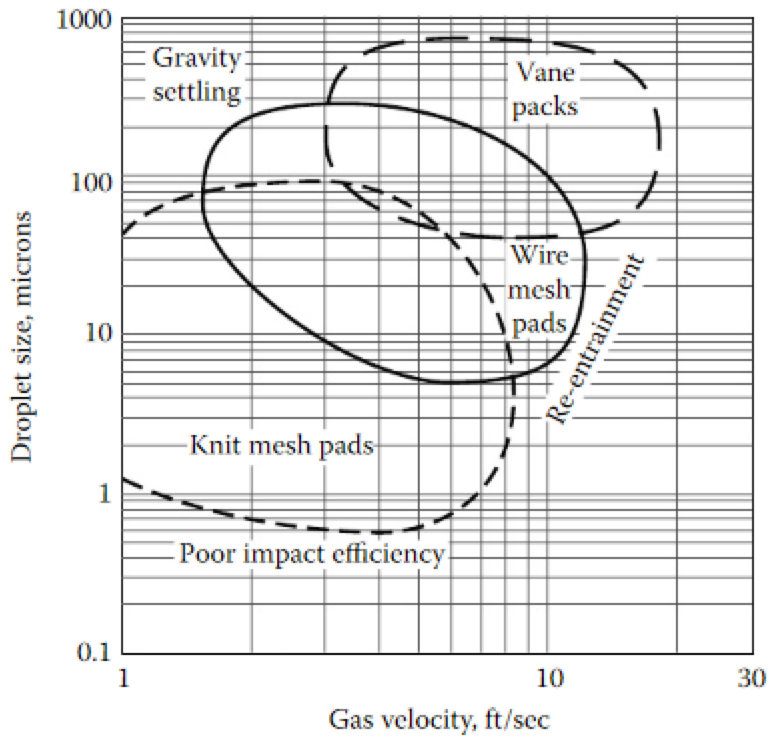


FIGURE 3.13 Approximate operating ranges for different kinds of demisters. Data are based upon water and air. (Courtesy of ACS Industries, 2005.)

- 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.

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).

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.

- Figure 3.14 shows a schematic of typical multi-pipe harp design for a slug catcher.

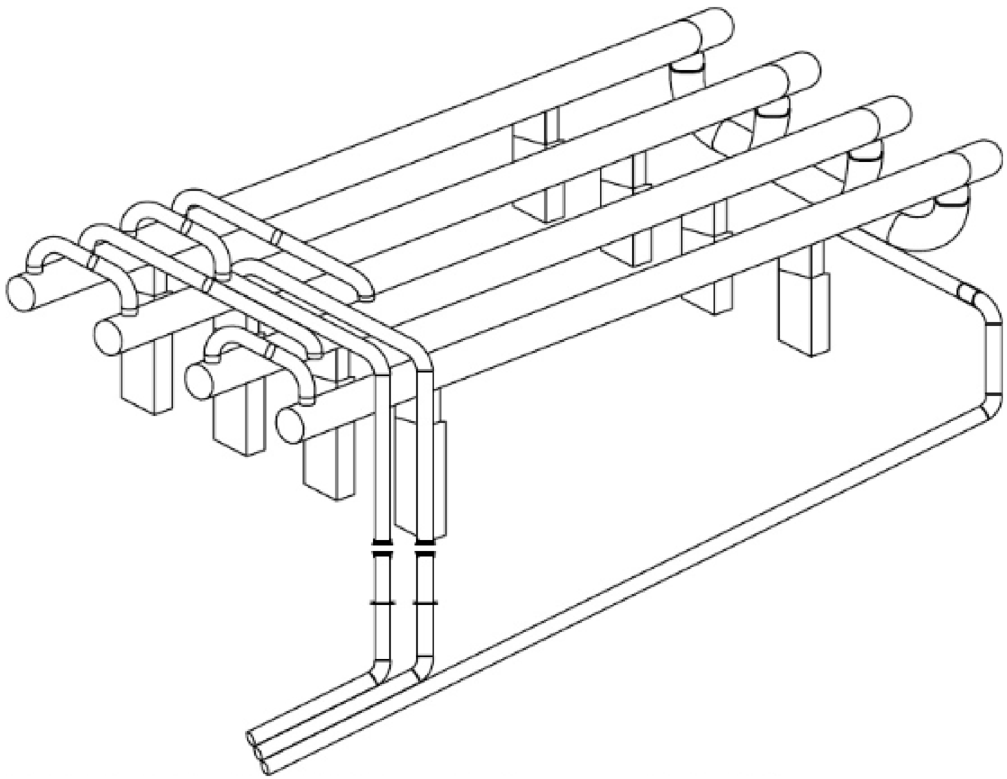


FIGURE 3.14 Schematic of multiple-pipe slug catcher. (Courtesy of Pearl Development Company.)

- 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.

Inlet vessels

- These slug catchers, commonly called inlet receivers, are simply gas-liquid separators that combine slug catching with liquid storage.
- They are usually employed where operating pressures are relatively low or where space is a problem.
- Horizontal vessels are preferred, unless area is limited (as on offshore platforms), because they provide the highest liquid surface area.
- Usually two or three vessels are manifolded together to permit larger volumes and to allow servicing of one vessel without plant disruption. Length-to-diameter ratios are typically 3:1 to 5:1 to maintain a low gas velocity through the gravity-settling section.

Comparison of slug catcher configurations

- Land or surface requirements

  : If no land constraints apply, piping is attractive. If constraints are severe, as on offshore platforms, vertical vessels are preferred. Otherwise horizontal vessels are the best choice.

- Operating pressure.

  : If inlet pressures are greater than about 500 psi(35 bar), significant savings in material costs can be achieved by use of the smaller diameter piping slug catcher.

- Gas-liquid separation capability.

  : Horizontal vessels provide the best separation, whereas piping provides the least because its main function is to catch liquid slugs. The large liquid surface area of horizontal vessels provides the best degassing. Piping has the shortest gas residence time when liquid levels are properly maintained in the vessels. However, with piping, small diameter gas scrubbers can be used for demisting.

- Liquid storage.

  : Horizontal vessels can act as primary liquid storage, whereas liquids from vertical vessels and piping must be sent to another vessel. Regardless of slug catcher used, liquids will go to low-pressure flash drums to recover light ends.

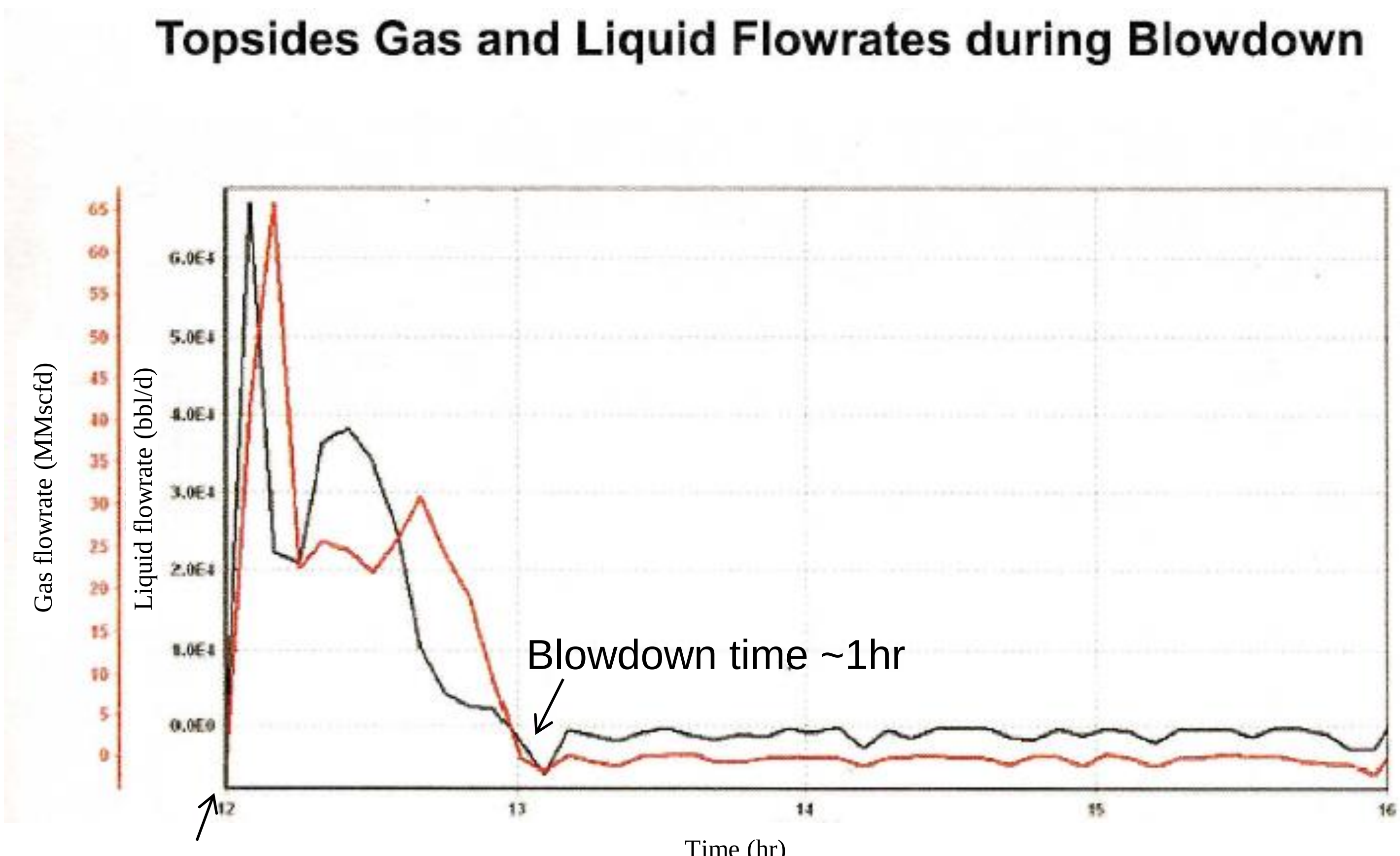
Applications for transient multiphase simulators

- The uses for transient multiphase flow *simulators* include*:*
  - Slug flow modeling
  - Estimates of the potential for terrain slugging
  - Pigging simulation
  - Identification of areas with higher corrosion potential, such as water accumulation in low spots in the line and areas with highly turbulent/slug flow
  - Startup, shutdown and pipeline depressurizing simulations
  - Slug catcher design
  - Development of operating guidelines
  - Real time modeling including leak detection
  - Operator training
  - Design of control systems for downstream equipment

Flowline depressurization or blowdown

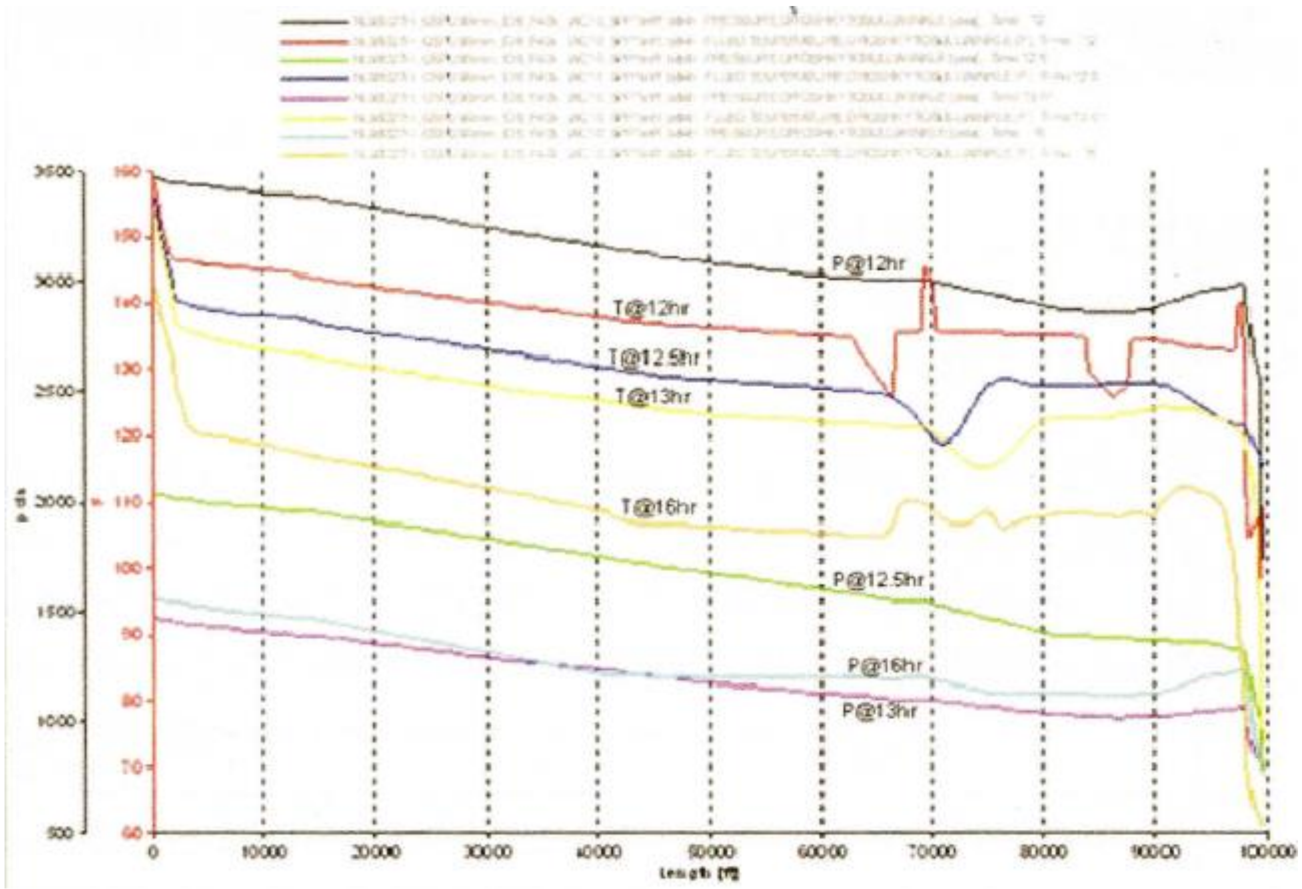
- Depressurization generally refers to the relatively slow evacuation of a pipeline system. Blowdown generally refers to the rapid evacuation of a pipeline.
- Depressurizing is usually performed to make the pipeline available for maintenance or repair. Depressurizing a pipeline will usually take quite 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



Start time of blowdown

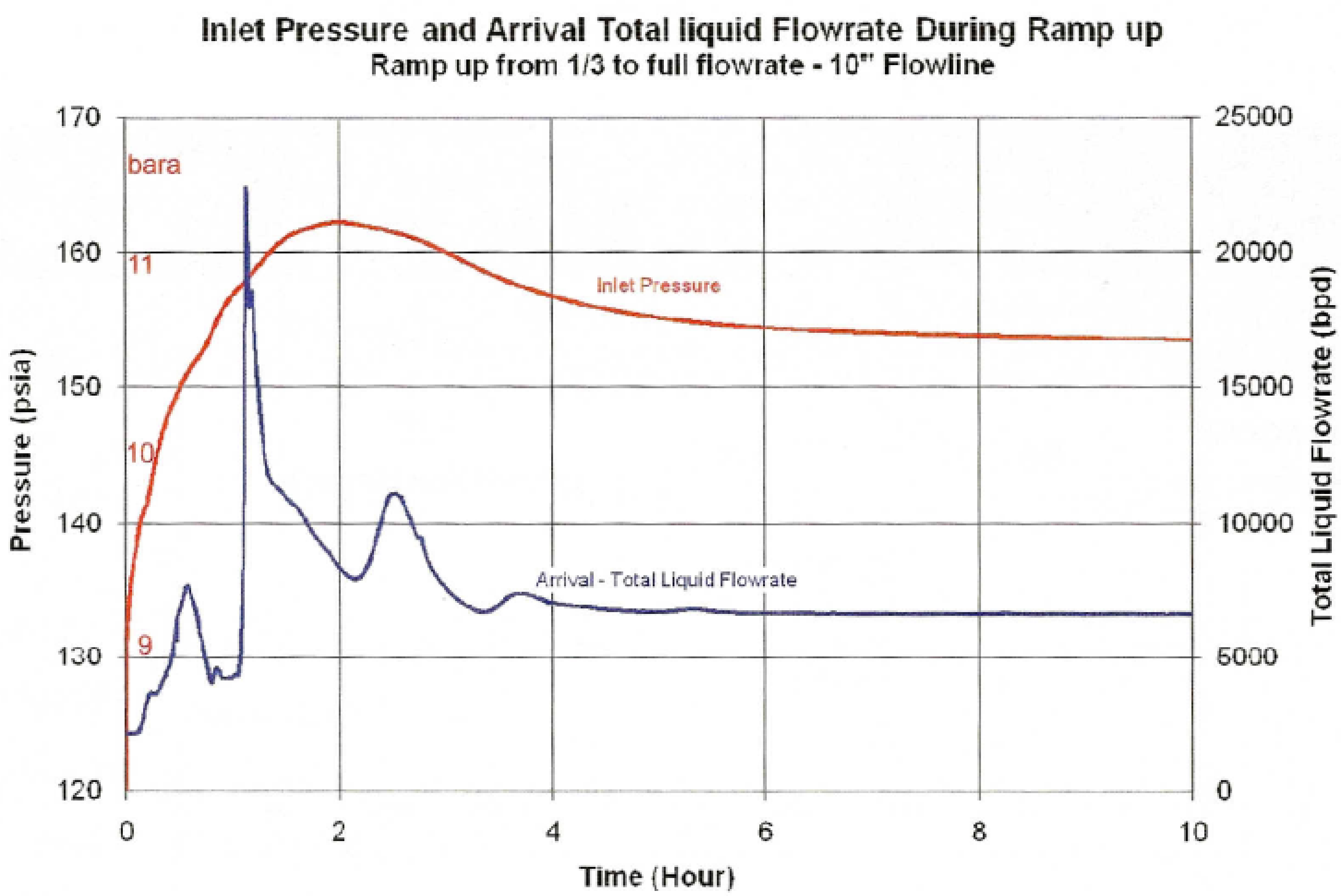
Flowline T & P profiles during blowdown



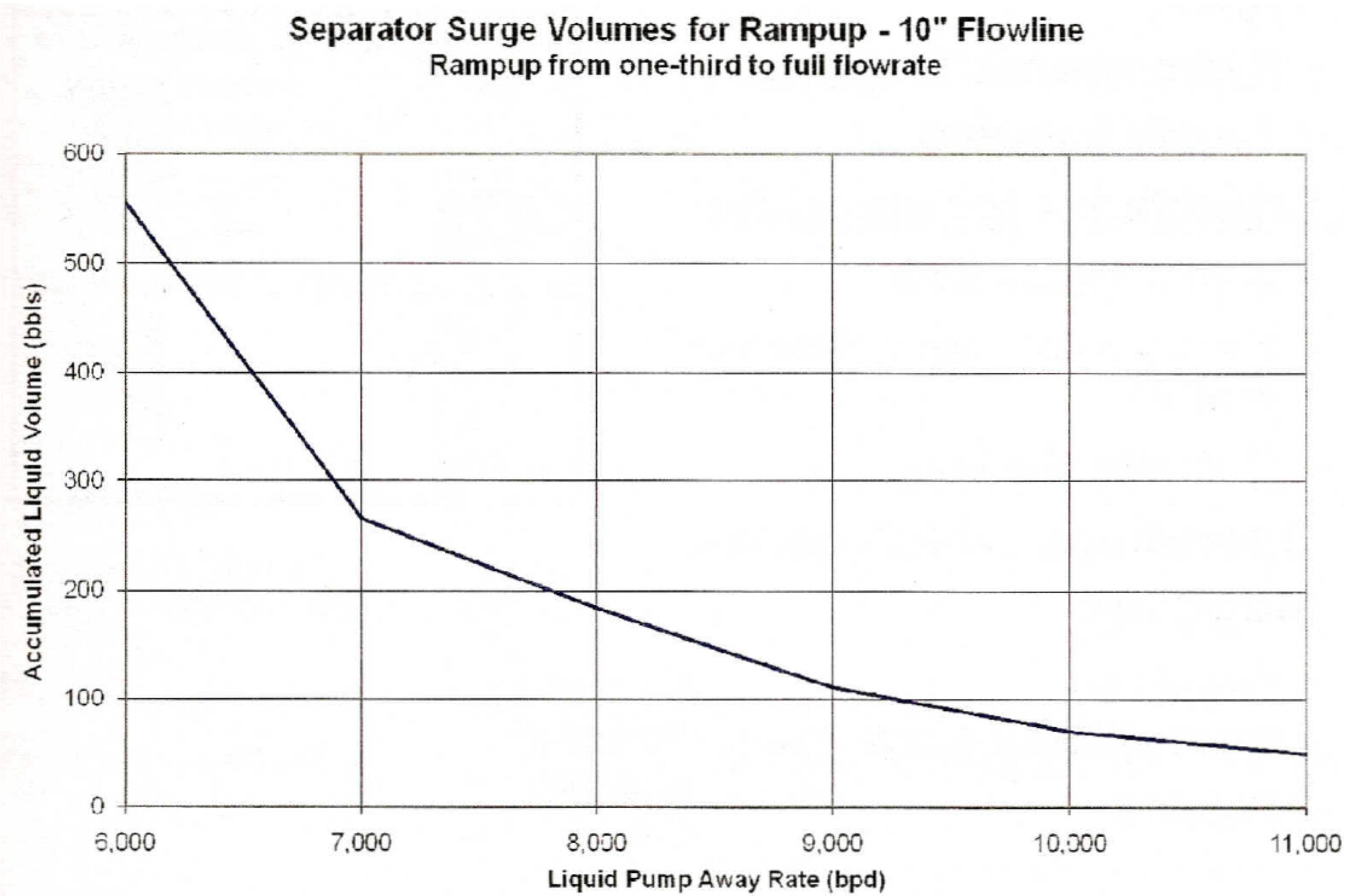
Blowdown results

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



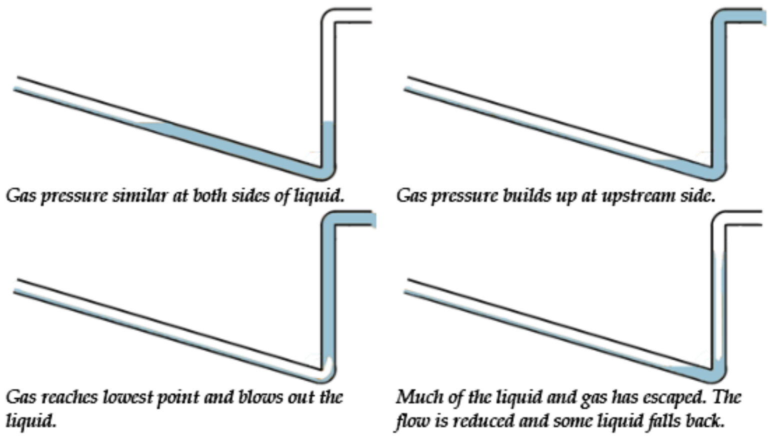
Separator surge volume during ramp up



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

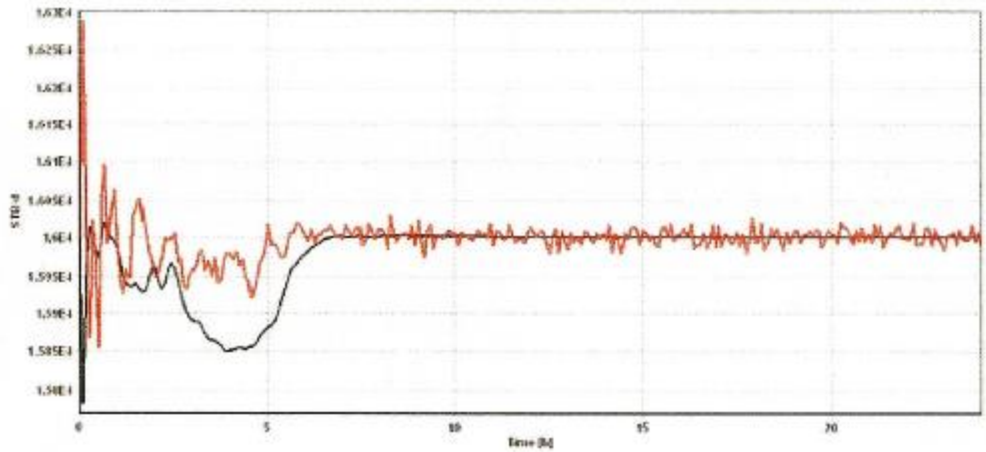
Caused by Flowrate changes



Moderate flowrate slugging

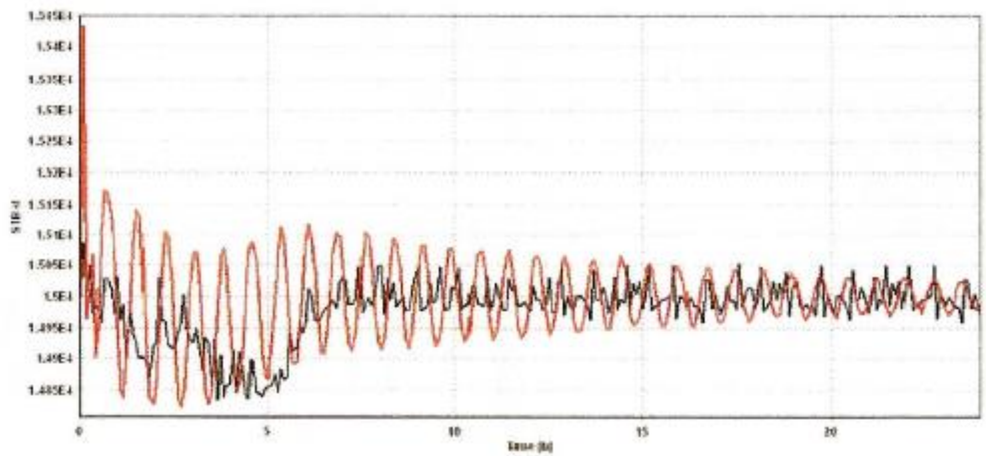
Slugging at 16kbopd
Average production rate
WC = 10%
WC = 80%

Max liquid rate = 16.3kblpd



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

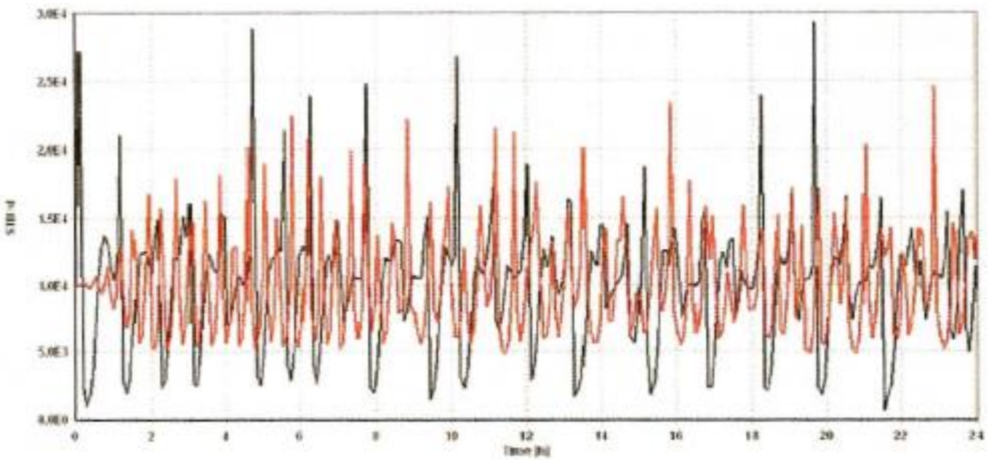
Max liquid rate = 15.4kblpd



Low flowrate slugging

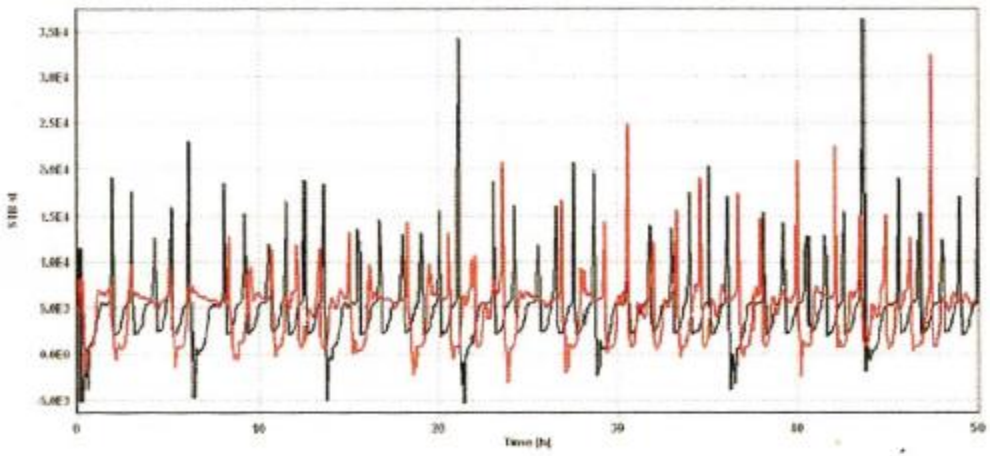
Slugging at 10kbopd
Average production rate
WC = 10%
WC = 80%

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

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.

Need for a slug catcher

- During non-steady state conditions (such as start-up, shutdown, turndown, and pigging) or when slugging during normal production occurs (low flowrates)
- The process controllers alone may not be able to sufficiently compensate for the wide variations in fluid flow rates, vessel liquid levels, fluid velocities, and system pressure caused by the slugs

Hydrodynamic slug size prediction (FPS vs SI)

- $$\ln(L_s) = -25.4144 + 28.4948\left(\ln(d)\right)^{0.1}$$

  where :

  L_s = *average slug length , ft*

  d = *pipe inside diameter , in*

- $$\ln(L_s) = -65.807 + 59.115\left(\ln(d)\right)^{0.1}$$

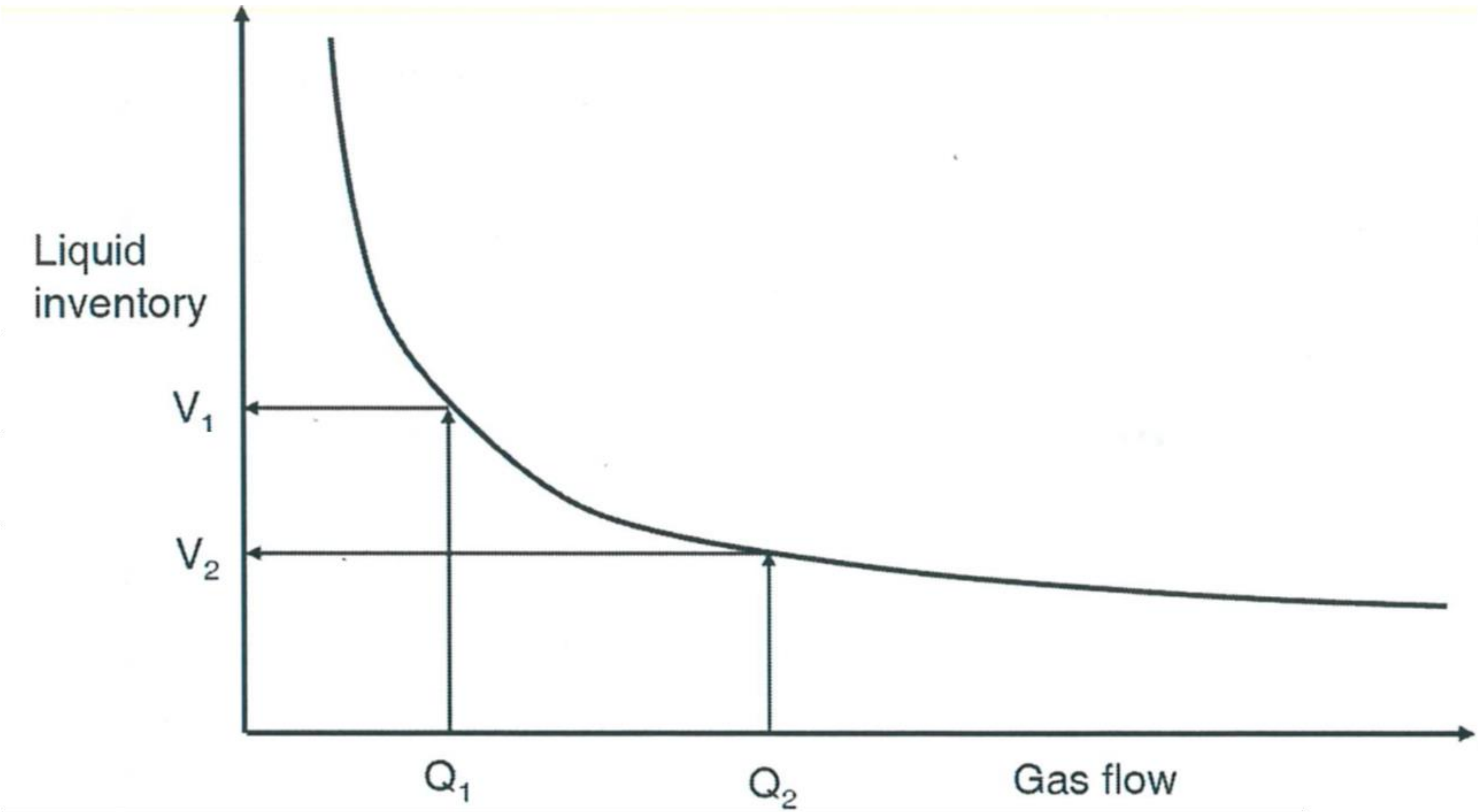
  where :

  L_s = *average slug length, m*

  d = *pipe inside diameter, mm*

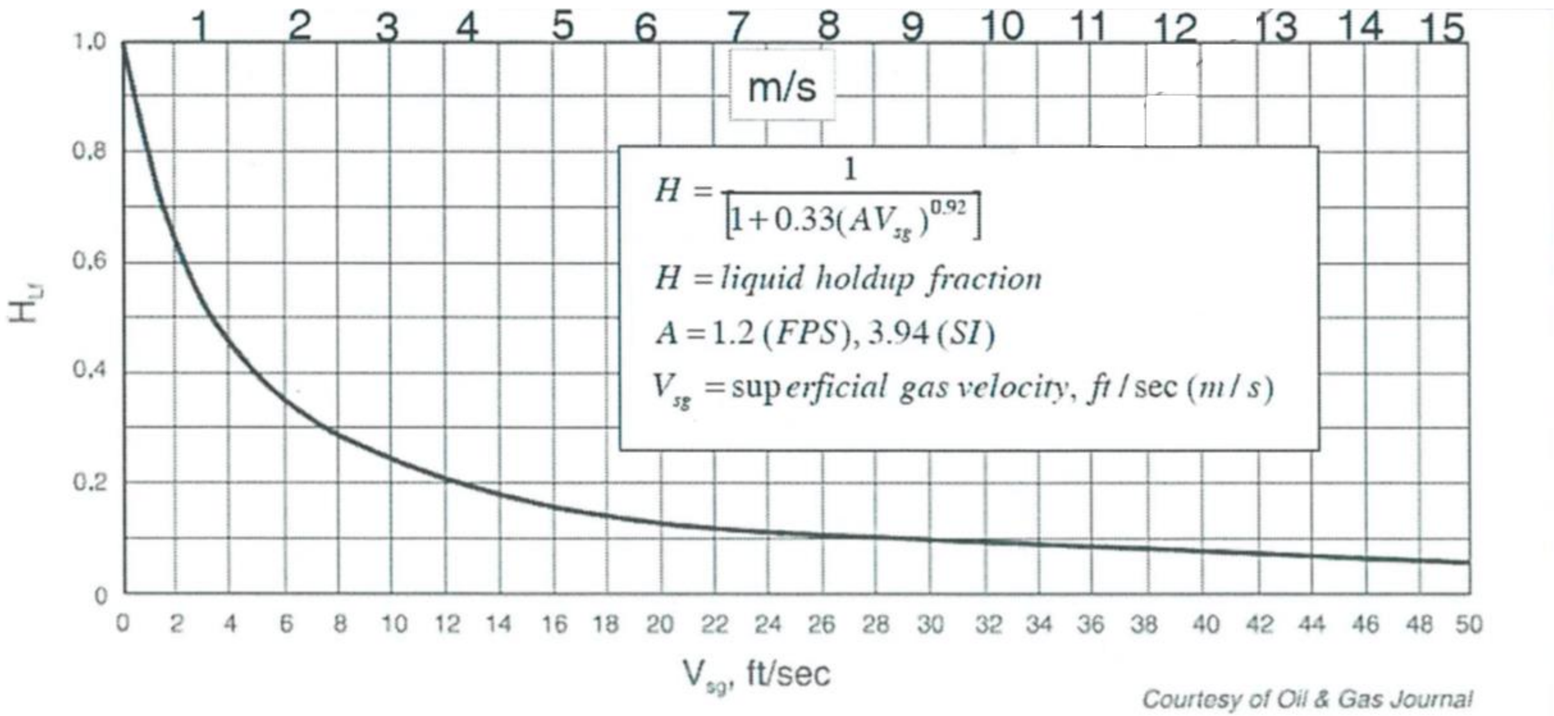
- Design slug length typically taken as 4 ~ 5 times L_s

Pipeline liquid holdup



Simple holdup correlation - Flanigan

- Slug size is based on "Hold Up" difference between flow rate 1 and 2

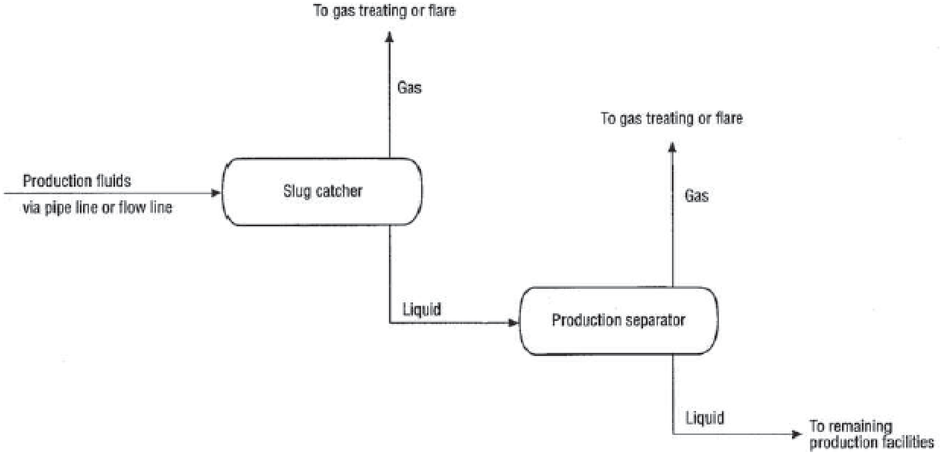


where, $V_{sg} = A \frac{q_g \, z \, T}{d^2 \, P}$

q_g *in* MMm^3/d, *T in K, d in m, P in kPa, A in 5.19 (SI)*

Slug catcher function – liquid/gas separation

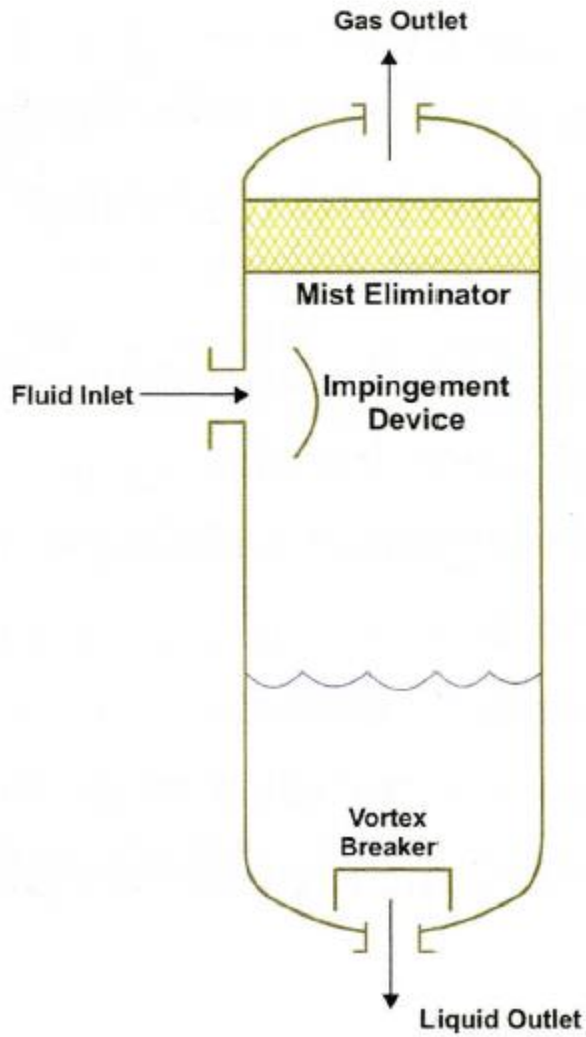
- Process stabilization is the primary purpose of the slug catcher.
- A slug catcher provides sufficient volume to dampen the effects of flow rate surges in order to minimize mechanical damage and deliver a more even supply of gas and liquid to the rest of the production facilities; minimizing process and operation upsets.
- A second function of the slug catcher is to provide preliminary separation of multiphase production fluids into separate gas and liquid streams. This is done to improve the efficiency of the process separator.



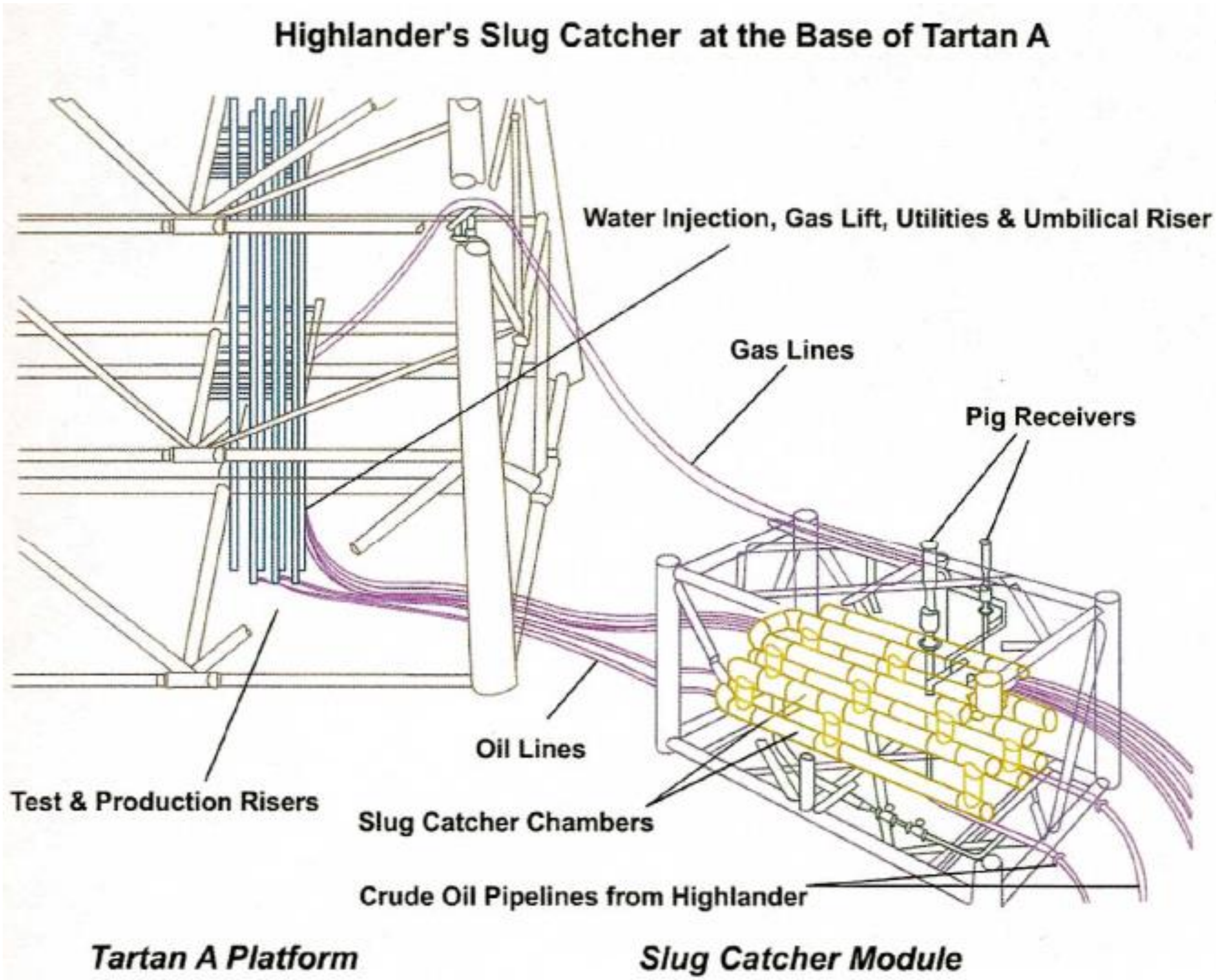
Slug catcher design

- The goal of a slug catcher design is to properly configure and size the slug catcher for the production flowline conditions.
- The design steps are as follows:
  1. Determine the functional requirements
  2. Determine slug catcher location
  3. Select the preliminary slug catcher configuration
  4. Compile design data
  5. Establish the design criteria
  6. Estimate the slug catcher size and dimensions
  7. Review for feasibility and repeat steps 2-6 as necessary

Vertical slug catcher

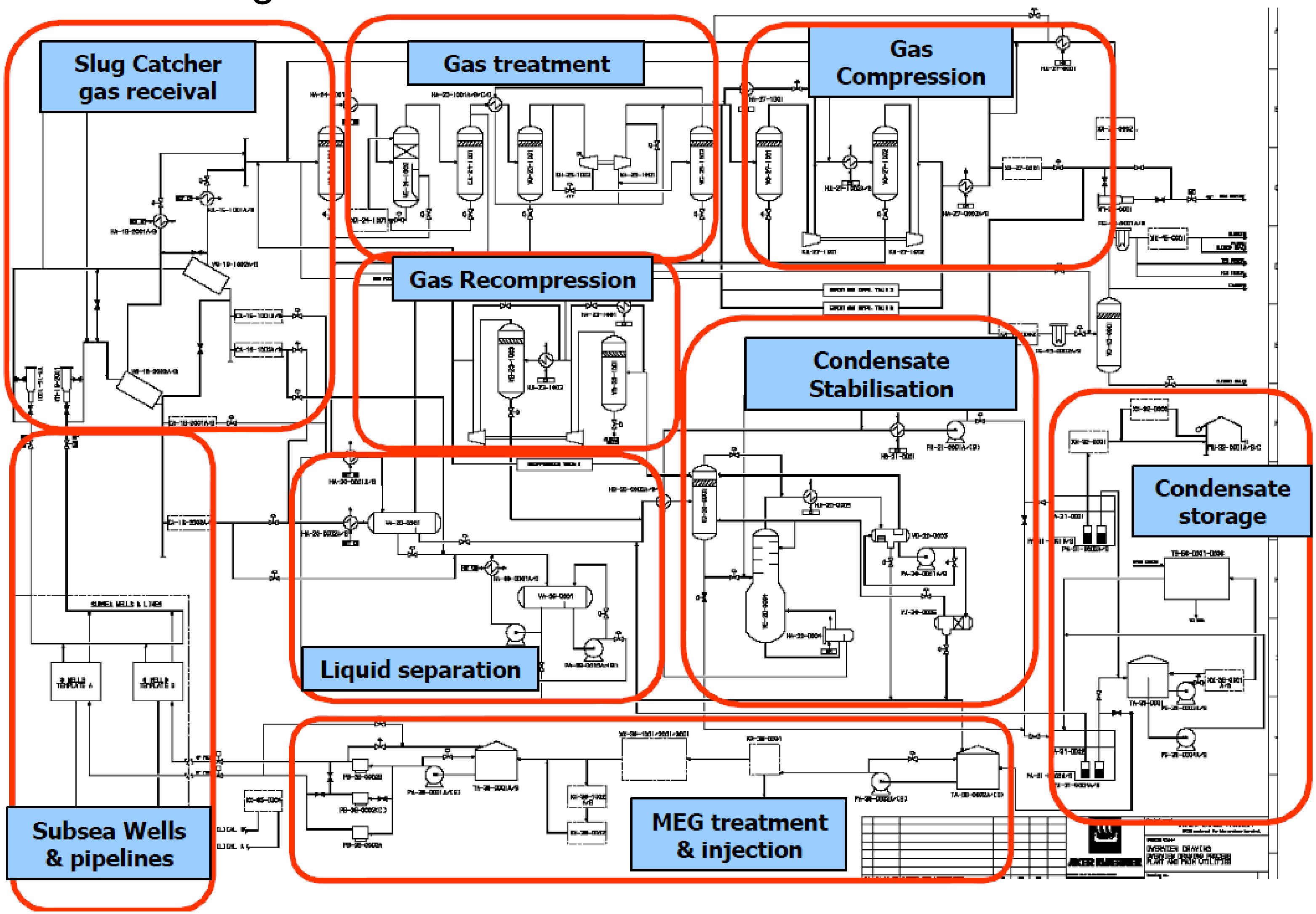


Subsea slug catcher



Gas condensate flowline slug catcher

- Ormen Lange




2 Slug Catcher units 1500m³ capacity
Can be connected to provide 3000m³ capacity

Thank you!