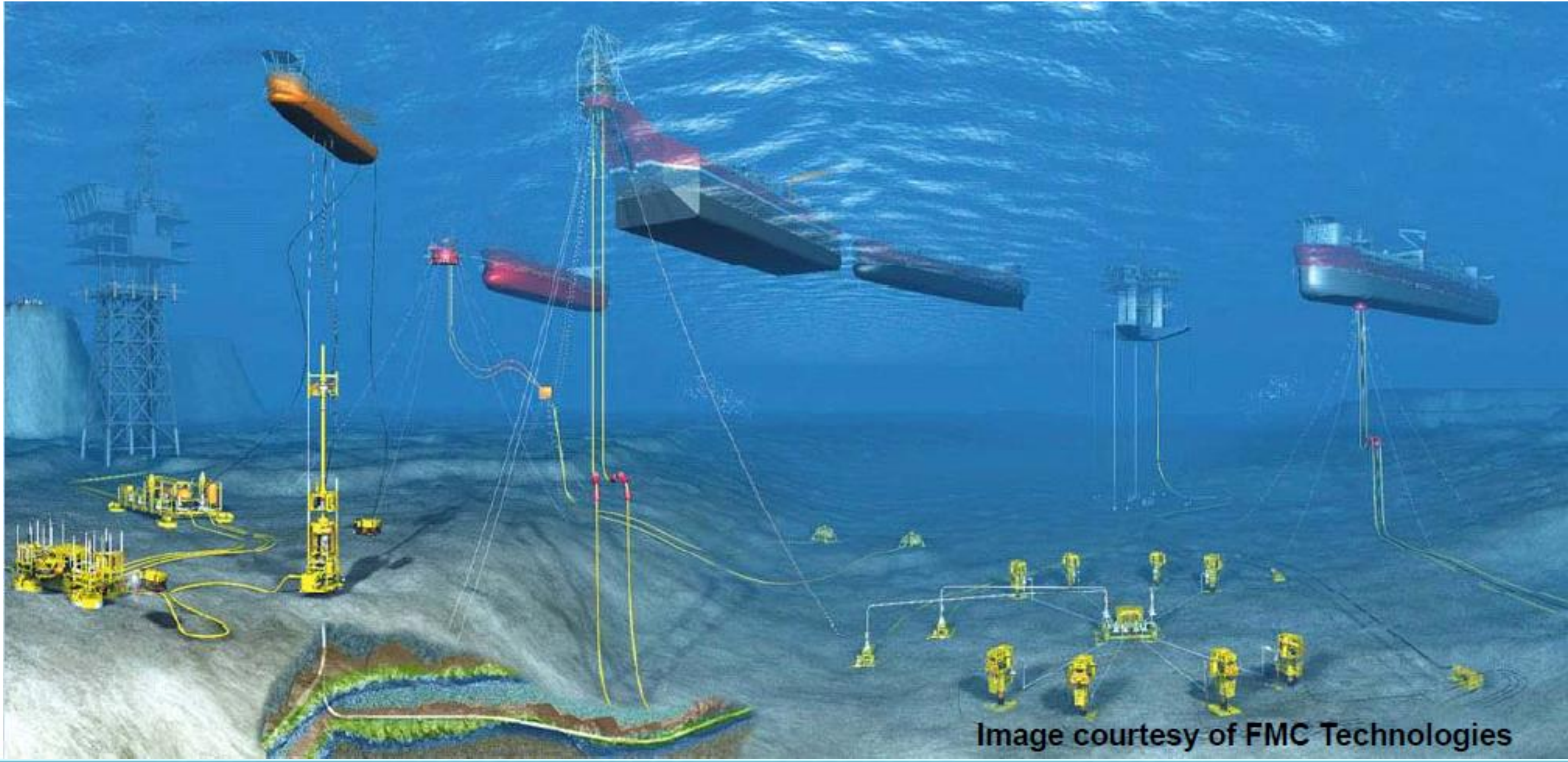


해저 공학

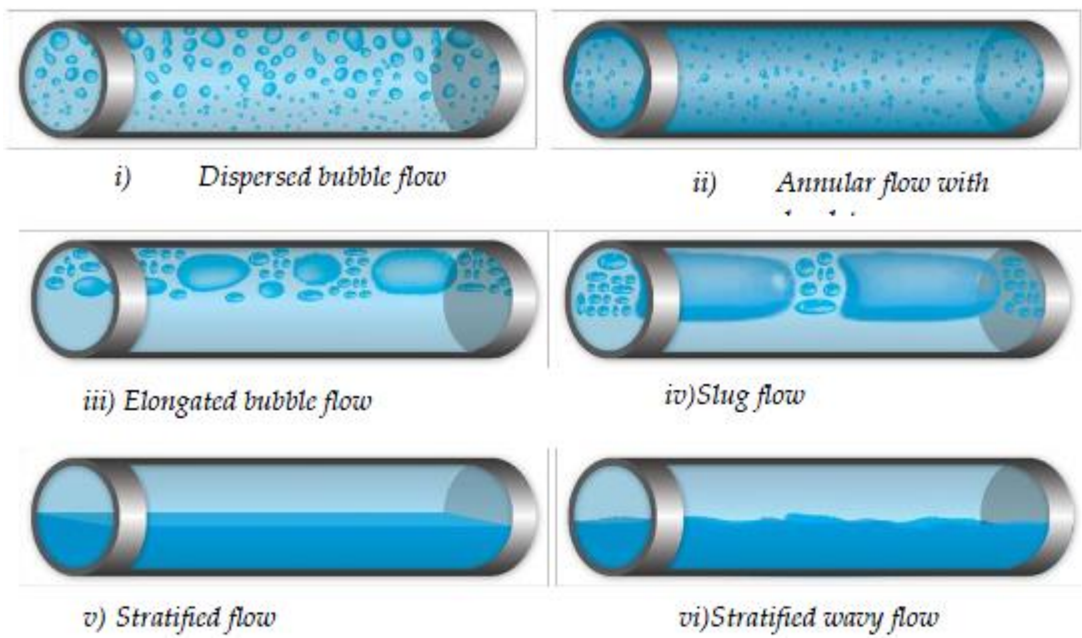
서유택

Multiphase flow regimes

- Multiphase flow patterns depend on the gas and liquid properties, velocities, and the angle of inclination of the flowline
- There are four back flow regimes:
    1. Slug flow
    2. Stratified flow
    3. Dispersed bubble flow
    4. Annular flow

Flow regime for near horizontal flow

- One of the most challenging aspects of dealing with multi-phase flow is the fact that it can take many different forms.



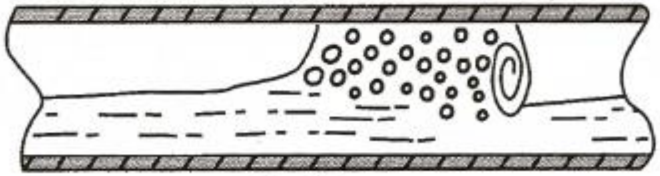
Stratified flow

- Stratified flow occurs at low flow rates in horizontal or downward inclined pipes, the liquid and gas separate due to gravity (gravity dominates over mixing)
  - At low gas velocities, the liquid surface is smooth.
  - At higher gas velocities, the liquid surface becomes wavy.
  - Most downwardly inclined pipes are in stratified flow.

Stratified Flow

Slug flow

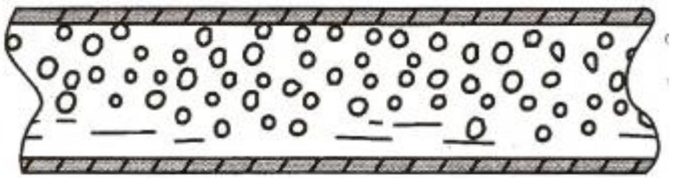
- Hydrodynamic slug flow occurs for near horizontal flow at moderate velocities. Waves on the liquid surface may grow to completely bridge the pipe. When this happens, alternating slugs of liquid and gas flow through the pipeline.
    - It is an unsteady, alternating combination of dispersed bubble flow (liquid slug) and stratified flow (gas bubble).
    - Slug flow also occurs in near vertical flow. The slugs in vertical flow are generally smaller than those in horizontal flow.
    - It occurs for all angles of inclination, though more likely for upwardly inclined pipes than downwardly inclined.



Slug Flow

Dispersed bubble flow

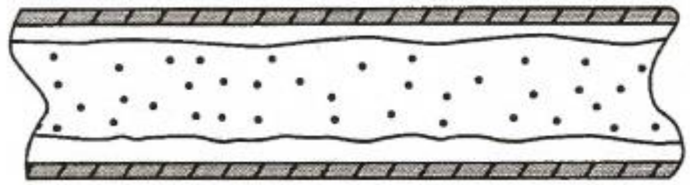
- Dispersed bubble flow occurs at high flowrates in liquid dominated systems, the flow is a mixture of liquid and small entrained gas bubbles (mixing dominates over gravity)
  - For vertical flow, dispersed bubble flow can occur at moderate liquid rates when the gas rate is low.
  - The flow is steady with little fluctuation.
  - It occurs at all angles of inclination.
  - It occurs frequently in oil wellbores.



Dispersed Bubble Flow

Annular flow

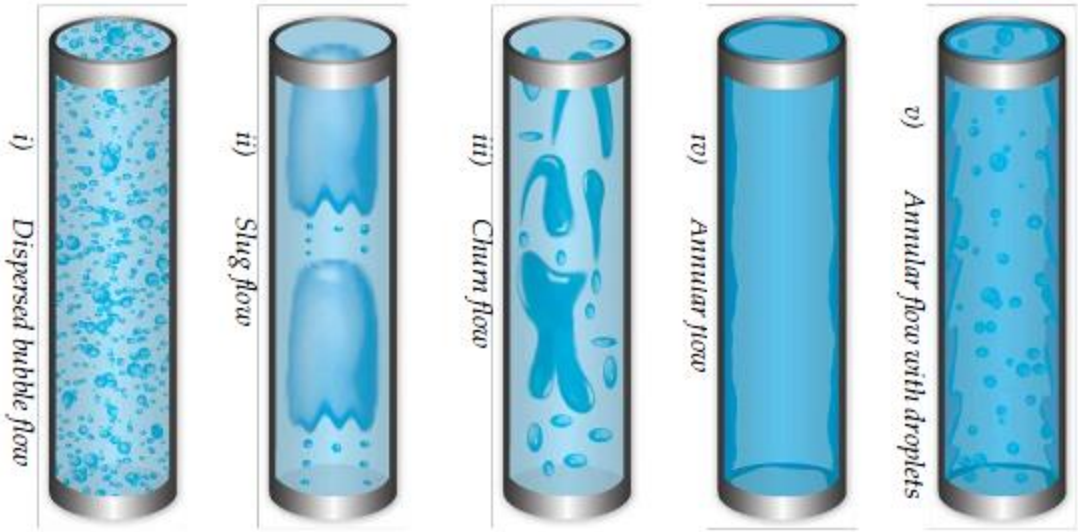
- Annular flow occurs at high flowrates in gas dominated systems. Liquid flows as a film around the circumference of the inner pipe wall. The gas and entrained liquid droplets flow in the center of the pipe
  - The liquid film thickness is basically constant for vertical flow but is asymmetric for horizontal flow.
  - As velocities increase, the fraction of entrained liquid increases.
  - Annular flow exists for all angles of inclinations .



Annular Flow

Flow regime in vertical pipe

- The flow regimes occurring in vertical are similar to those in horizontal pipes, but one difference being that the there is no lower side of the pipe which the densest fluid ‘prefers’. One of the implications this has is that stratified flow is not possible in vertical pipes.

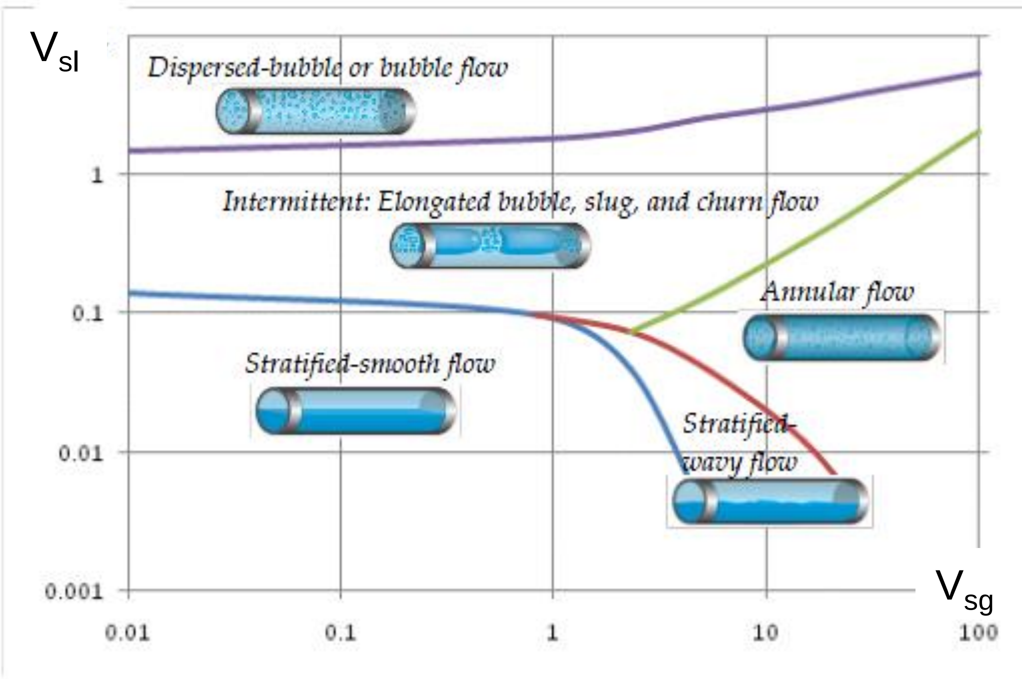


- *Bubble flow:* The liquid is continuous, with the gas phase existing as randomly distributed bubbles. The gas phase in bubble flow is small and contributes little to the pressure gradient except by its effect on the density.
- *Slug flow:* Both the gas and liquid phases significantly contribute to the pressure gradient. The gas phase in slug flow exists as large bubbles and is separated by slugs of liquid. The velocity of the gas bubbles is greater than that of the liquid slugs, thereby resulting in a liquid holdup that not only affects well and riser friction losses but also flowing density.
- *Churn flow:* The liquid slugs between the gas bubbles essentially disappear and at some point the liquid phase becomes discontinuous and the gas phase becomes continuous. The pressure losses are more the result of the gas phase than the liquid phase.
- *Annular flow:* This type of flow is characterized by a continuous gas phase with liquid occurring as entrained droplets in the gas stream and as a liquid film wetting the pipe wall.

Flow regime map for horizontal pipe

- Depict the transitions between the flow patterns.
- The superficial gas velocity (V_{sg}) is on the X-axis and the superficial liquid velocity (V_{sl}) is on the Y-axis.
- The flow pattern is also dependent on:

- the angle of inclination,
- pipe diameter,
- fluid composition,
- pressure and temperature.



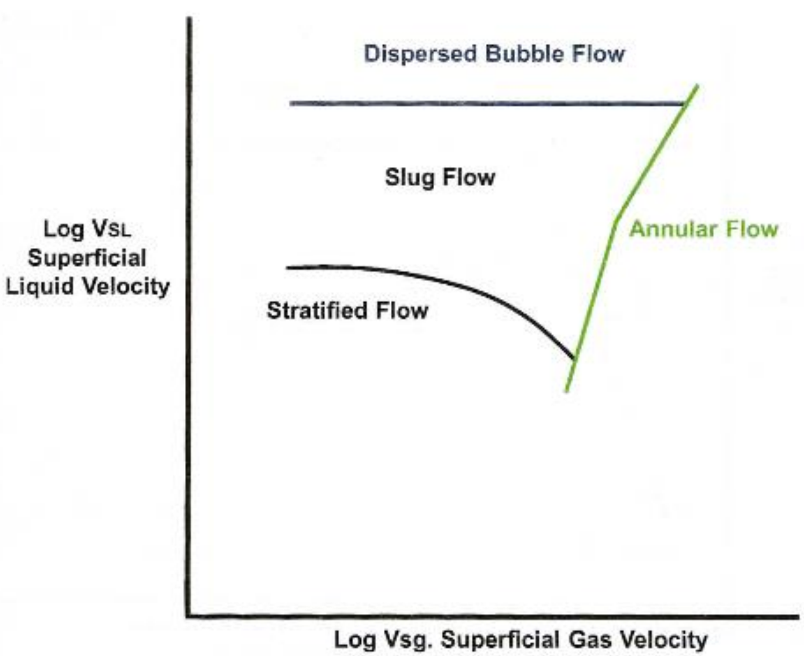
- Flow regime maps are useful tools for getting an overview over which flow regimes we can expect for a particular set of input data. Each map is not, however, general enough to be valid for other data sets.
- For very low superficial gas and liquid velocities the flow is stratified. As the velocities approach zero, we expect the pipe to act as a long, horizontal tank with liquid at the bottom and gas on top.
- If we increase the gas velocity, waves start forming on the liquid surface. Due to the friction between gas and liquid, increasing the gas flow will also affect the liquid by dragging it faster towards the outlet and thereby reducing the liquid level.

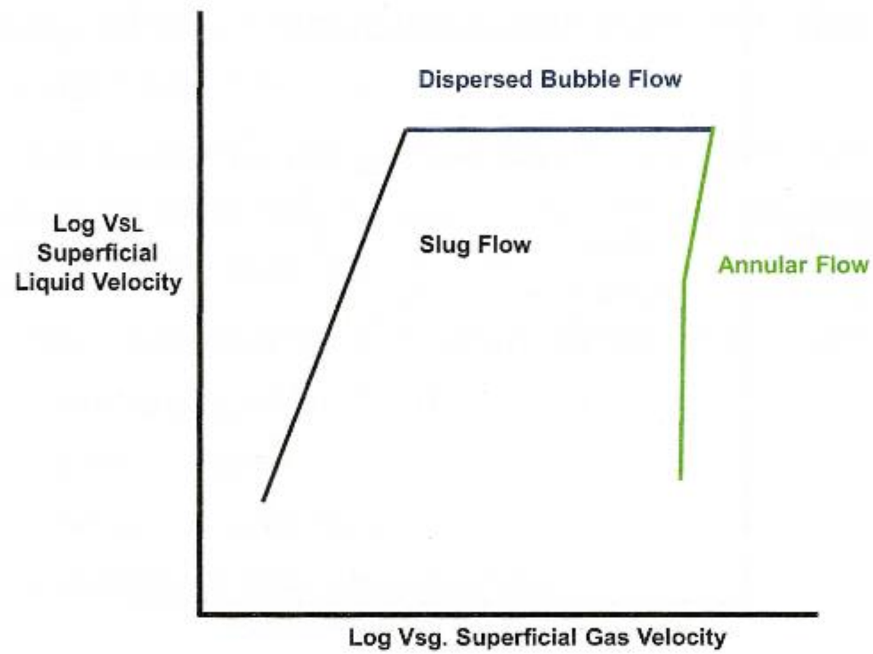
- If we continue to increase the gas flow further, the gas turbulence intensifies until it rips liquid from the liquid surface so droplets become entrained in the gas stream, while the previously horizontal surface bends around the inside of the pipe until it covers the whole circumference with a liquid film.
- The droplets are carried by the gas until they occasionally hit the pipe wall and are deposited back into the liquid film on the wall.
- If the liquid flow is very high, the turbulence will be strong, and any gas tends to be mixed into the liquid as fine bubbles. For somewhat lower liquid flows, the bubbles float towards the top-side of the pipe and cluster.
- The appropriate mix of gas and liquid can then form *Taylor-bubbles*, which is the name we sometimes use for the large gas bubbles separating liquid slugs.

- If the gas flow is constantly kept high enough, slugs will not form because the gas transports the liquid out so rapidly the liquid fraction stays low throughout the entire pipe.
- It is sometimes possible to take advantage of this and create *operational envelopes* that define how a pipeline should be operated, typically defining the minimum gas rate for slug-free flow.

Flow regime map: Horizontal vs. vertical pipe

- Similar flow regime maps can be drawn for vertical pipes and pipes with uphill or downhill inclinations.





Three- and four-phase flow

- Three phase flow is most often encountered as a mixture of gas, oil and water.
- The presence of sand or other particles can result in four phase flow, or we may have three-phase flow with solids instead of one of the other phases.
- Sand has the potential to build up and affect the flow or even block it. If we keep the velocities high enough, the sand is quickly transported out of the system, and we can often get away with neglecting the particles in the flow model.
- Instead, it is only taken into account in considerations to do with erosion or to establish minimum flow limits to avoid sand buildup. The three-phase flow our simulation models have to deal with are therefore primarily of the gas-liquid-liquid, and sand is only included – if at all - indirectly.

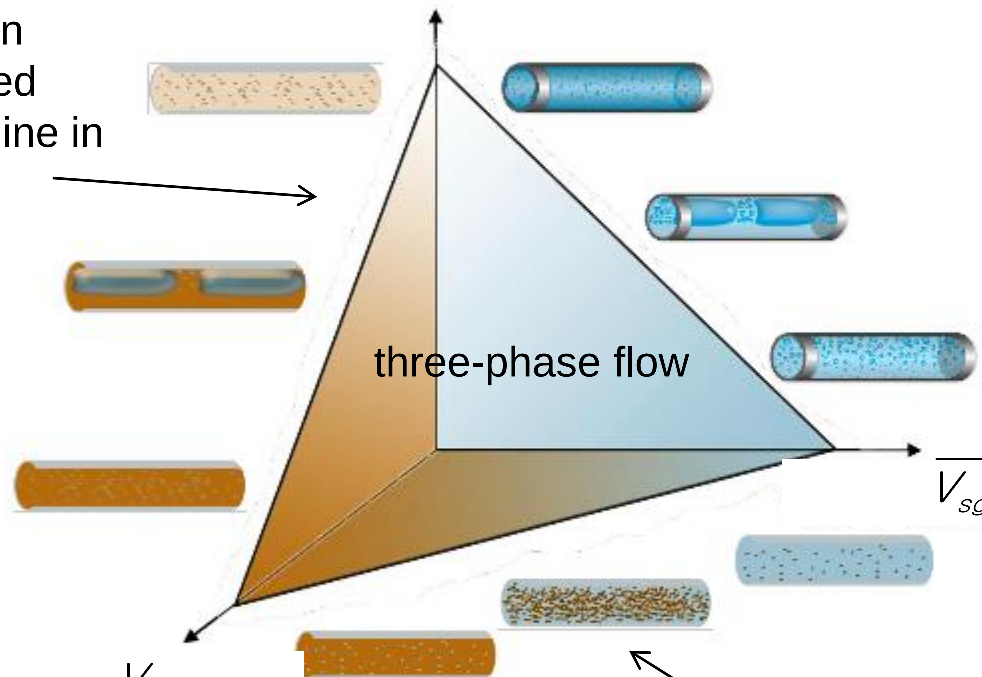
Three-phase flow regime

- It may be more convenient to illustrate three-phase flow as shown in three dimensions.

$$\frac{V_{sg}}{V_{sg}+V_{so}+V_{sw}}$$

It becomes 1 for pure gas flow

if the water content is zero, our operation point will be located somewhere on a line in the gas-oil plane



$$\frac{V_{sw}}{V_{sg}+V_{so}+V_{sw}}$$

$$\frac{V_{so}}{V_{sg}+V_{so}+V_{sw}}$$

The gas fraction is zero for pure liquid (oil-water) flow

Multiphase flow modeling

- 3-phase vs. 2-phase flow

- Most production flowlines have 3 phases (gas, oil, and water)

- Simulators can use 2-phase models with a mixed liquid stream using averaged properties for the oil and water.

- The use of 2-phase models generally gives acceptable results unless

: emulsions are present,

: flow rates are low enough to cause stratification of all three phases.

- 3-phase models are typically used in gas-condensate systems

- 3-phase flow modeling requires considerably more computing time because of the added complexity

Flowline pressure drop in multiphase flow

- The maximum allowable pressure drop in a pipeline is constrained by its required outlet pressure and available inlet pressure. In addition, the pressure in a pipeline must always be less than the maximum allowable operating pressure.
- Allowable pressure drop is a function of the parameters of the flow system. No fixed criteria exist for determining the maximum pressure drop for a pipeline design.
- The flowline pressure gradient consists of three elements:

  1. Friction
  2. Elevation changes (can be + or -)
  3. Fluid acceleration (can be + or -)

Steady state production flowline pressure drops

- Rules of Thumb for Frictional Pressure Drops
  - Gas or Gas Condensate Production Flowline: 10-20 psi per mile
  - Oil Production Flowline: 50-250 psi per mile
  - Note: Hydrostatic head needs to be accounted to determine the total pressure drop
  - Conservative estimate for production flowlines (with only reservoir energy to promote flow): the pressure drop at maximum flowrate should be about 1/3 of the difference between the initial FWHP and the required arrival pressure at the host.
- Flowline capacity can be limited by ΔP or by EVR (erosion velocity ratio)

Single phase steady state flow in pipes

$$\frac{dp}{dx} = \frac{\tau_w \pi D}{A} + \rho g_c \sin\theta + \rho u \frac{du}{dx}$$

Where

P = pressure

D = pipe diameter

ρ = fluid density

u = velocity in x direction

τ_w = wall shear stress

A = internal cross sectional area

g_c = gravitational constant

Tow-phase homogeneous flow pressure gradient equation

$$\frac{dp}{dx} = \tau_{wg}\frac{P_g}{A} + \tau_{wl}\frac{P_l}{A} + \left(\alpha_g\rho_g + \alpha_l\rho_l\right)g_c \sin\theta + \frac{d}{dx}\left(\alpha_g\rho_g u_{sg}^2 + \alpha_l\rho_l u_{sl}^2\right)$$

$$+ \ [\mathit{shear\ effects\ between\ gas\ and\ liquid}]$$

P: wetted perimeters for gas and liquid

ρ : density

α : mass fraction

g_c : gravitational constant

u : velocity

τ : shear stress

θ : inclination angle

p: pressure

l : liquid

g : gas

x : distance

Frictional losses

- In multiphase flow, frictional losses occur by two mechanisms: friction between the gas or liquid and the pipe wall, and frictional losses at the interface between the gas and liquid.

- The friction calculations, therefore, are highly dependent on the flow regime, since the distribution of liquid and gas in the pipe changes markedly for each regime.

Elevation

- Elevation "losses" can be major factor in vertical flow and flow through hilly terrain
- The liquid holdup must be determined to calculate elevation effects
- Holdup in each flow regime has its own sensitivity to operating variables

Acceleration

- Acceleration losses are only significant for annular flow and slug flow; and especially for liquid to gas phase changes
- Typically, acceleration is usually less than 1% of the total drop
- In slug flow, acceleration of the liquid in the slug front can produce significant pressure losses

Uncertainty in pressure drop calculations

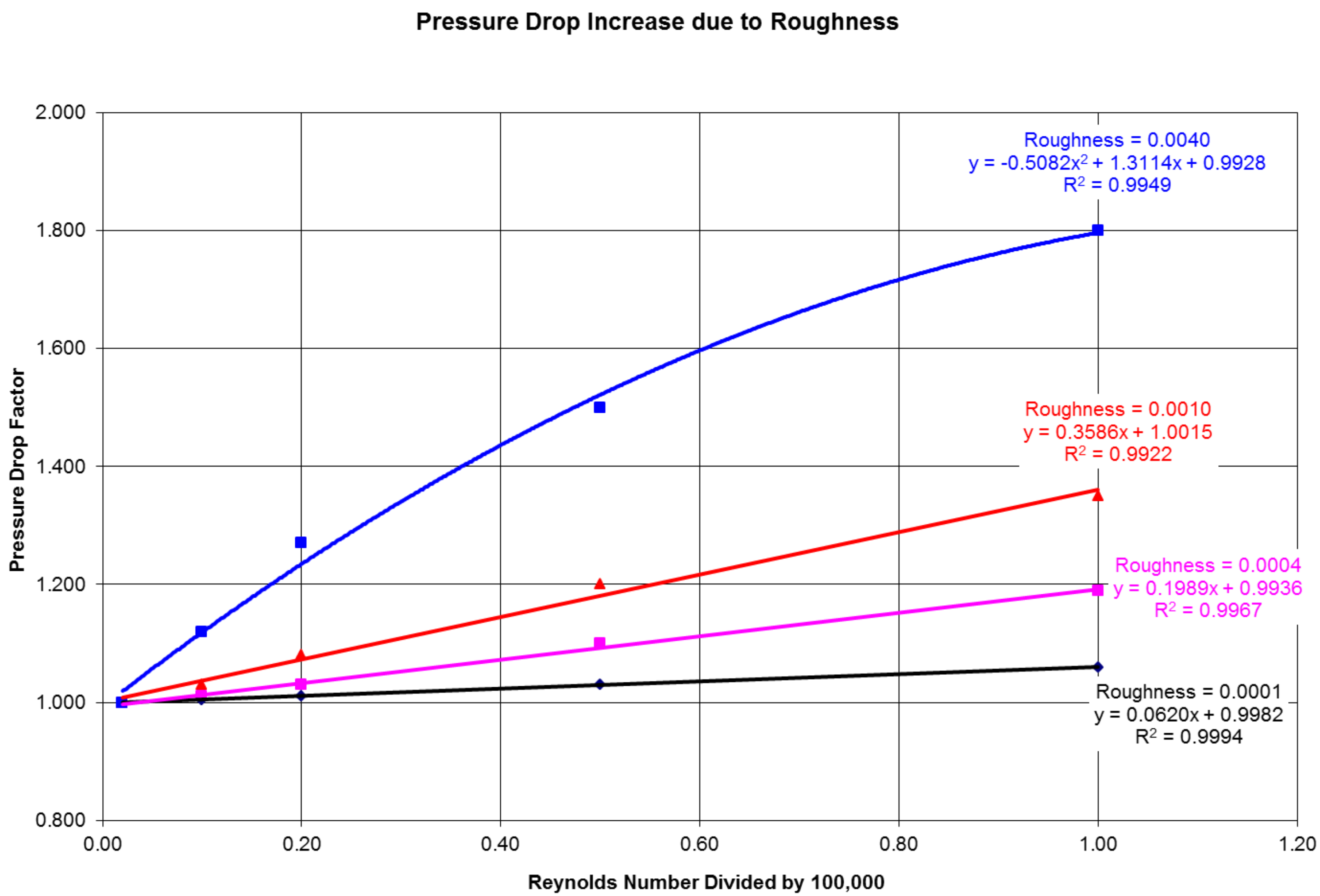
- Due to the complexity of multi phase flow, uncertainties associated with pressure drop calculations are significantly greater than those in single-phase flow, and can have errors in excess of ± 20%.

- These errors will be increased if the terrain is rugged, the fluid properties are not fully defined or if the velocities are particularly high or low.

- The uncertainty is a result of the fact that many pressure drop methods are empirically based and are therefore only valid for the range of conditions over which they were derived.

Pipeline wall roughness

- The relative roughness is defined as the absolute pipe roughness (which can be thought of as the surface-to-peak height of protrusions on the metal surface divided by the pipe diameter. The Moody chart gives the Fanning friction factor as a function of Reynolds number and relative roughness.
- A new steel pipe is usually assumed to have an absolute roughness of about 0.0018 inch. In a 10-inch pipe, that converts to a relative roughness of about 0.0002. An aged, corroded pipe will have a much rougher surface. There can be a factor of about two between the pressure drop between new and aged pipe. Since flow rate is roughly proportional to the square root of pressure drop, the new smooth pipe could have a capacity 40 percent greater than the corroded pipe.


Pressure Drop Increase due to Roughness
Pressure Drop Factor
Reynolds Number Divided by 100,000
2.000
1.800
1.600
1.400
1.200
1.000
0.800
0.00
0.20
0.40
0.60
0.80
1.00
1.20
Roughness = 0.0040
y = -0.5082x2 + 1.3114x + 0.9928
R2 = 0.9949
Roughness = 0.0010
y = 0.3586x + 1.0015
R2 = 0.9922
Roughness = 0.0004
y = 0.1989x + 0.9936
R2 = 0.9967
Roughness = 0.0001
y = 0.0620x + 0.9982
R2 = 0.9994

Slip between gas and liquid phases

- Under most pipe flow conditions, the liquid moves more slowly than the gas because it is more dense and viscous.

- Both phases would move through the pipe at the same velocity if there were no slip between the gas and liquid.

Liquid holdup

- Liquid holdup is the amount of liquid contained in a multi phase pipeline at particular flow conditions. Pipeline liquid holdup is a factor of major importance for operability of a pipeline.
- Differences in holdup at different flow conditions represent the liquid that will be swept out of the line during an increase in flow rate.
- The holdup at a particular time will be produced as a liquid slug when the line is pigged.
- These aspects affect slug catcher sizing and peak onshore liquid processing requirements

Liquid holdup formation

- The liquid phase is normally carried though the line by drag forces exerted by the gas phase.
- In upward sloping sections of the pipeline this drag must overcome both frictional and gravitational forces - this causes liquid to accumulate in these sections so as to reduce the flow area for the gas, increasing the drag to the level required to carry the liquid uphill.
- The accumulation of liquid in uphill sections means that the use of a representative topography for a pipeline is vital in predicting liquid.

- Below a certain gas flow rate (which is different for each pipeline and is often referred to as the “sweep velocity”) the holdup rapidly increases as the gas velocity is further lowered. In this region the holdup appears to depend far more on gas velocity than upon the amount of liquid in the fluids.
- Above the sweep velocity the holdup only slightly decreases as gas velocity is further increased. In this region the hold-up appears to be mostly dependent upon the amount of liquid in the fluids.

Liquid holdup variable sensitivities

- The influence of the major variables on liquid holdup is very different for each of the flow regimes. As a result, it is impossible to develop a general holdup correlation that will apply to all the flow regimes

	Slug flow	Annular flow	Stratified flow	Dispersed bubble flow
Superficial gas velocity	Strong	Strong	Strong	Strong
Superficial liquid velocity	Strong	Strong	Strong	Strong
Gas density	Moderate	Strong	Strong	Strong
Pipeline diameter	Moderate	Weak	Weak	Weak
Angle of inclination	Moderate	Weak	Very strong	None
Liquid properties	Moderate	Moderate	Moderate	Weak

Pressure drop and liquid holdup

- In a multiphase pipeline, pressure drop is not always the maximum at the highest flowrate.
- If a pipeline contains significant "hills and valleys", it is possible that the highest pressure drop occurs at a lower flowrate. This is due to increased liquid holdup at lower flowrate.

Steady state multiphase flow modeling

- Most offshore pipelines are sized by use of three design criteria: available pressure drop, allowable velocities, and slugging.

- Line sizing is usually performed by use of steady state simulators, which assume that the temperatures, pressures, flowrates, and liquid holdup in the pipeline are constant with time. This assumption is rarely true in practice, but line sizes calculated from the steady state models are usually adequate.

Flow velocity

- The velocity in multiphase flow pipelines should be kept within certain limits to ensure proper operation.
- Operating problems can occur if the velocity is either too high or too low. There are guidelines to determining these limits, but they are not absolute values.

Maximum flow velocity and erosion

- Solids Free Erosion Velocity limits can be determined using API RP14E, given in the equation below. V_e is the maximum velocity allowed to avoid excessive corrosion/erosion.

$$V_e = \frac{C}{\sqrt{\rho_{mix}}}$$

Where,

V_e = erosional velocity (ft/s)

C = empirical coefficient

ρ_{mix} = gas/liquid mixture density (lb/ft^3), which is defined as

$$\rho_{mix} = C_L \rho_L + (1 - C_L)\rho_g$$

Where,

ρ_{mix} = liquid density,

ρ_{gas} = gas density,

C_L = flowling liquid volume fraction ($C_L = Q_L / (Q_L + Q_G)$)

- The above equation attempts to indicate the velocity at which erosion-corrosion begins to increase rapidly.
- This equation is an over-simplification of a highly complex subject, and as a result, there has been considerable controversy over its use.
- For wells with no sand present, values of C have been reported to be as high as 300 without significant erosion/corrosion in carbon steel pipes.

Table 13-9 Empirical Constant in the Equation

Service Type	Operational Frequency: Continuous	Operational Frequency: Intermittent
Two-phase flow without sand	100	125

If possible, the minimum velocity in two-phase lines should be greater than 3 m/s (10 ft/s) to minimize slugging.

Material	C Factor $lb^{0.5} / ft^{0.5}.sec$
Carbon steel	135
CRA	300
Flexible risers	200

- For flowlines with significant amounts of sand present, there has been considerable erosion-corrosion for lines operating below C = 100.
- Assuming on erosion rate of 10 mils per year, the following maximum allowable velocity is recommended by Salama and Venkatesh, when sand appears in an oil/gas mixture flow:

$$V_M = \frac{4d}{\sqrt{W_s}}$$

Where,

V_M = maximum allowable mixture velocity (ft/s)

d = pipeline inside diameter, in.

W_s = rate of sand production (bbl/month)

Minimum flow velocity

- The concept of a minimum velocity for a flowline is also important.
- Velocities that are too low are frequently a greater problem than excessive velocities.
- The following items may effectively impose minimum velocity constraints:

  Slugging: Slugging severity typically increases with decreasing flow rate. The minimum allowable velocity constraint should be imposed to control the slugging in multiphase flow for assuring the production deliverability of the system.

  Liquid handling: In gas/condensate systems, the ramp-up rates may be limited by the liquid handling facilities and constrained by the maximum line size.

  Pressure drop: For viscous oils, a minimum flow rate is necessary to maintain fluid temperature such that the viscosities are acceptable. Below this minimum, production may eventually shut itself in.

Liquid loading: A minimum velocity is required to lift the liquids and prevent wells and risers from loading up with liquid and shutting in. The minimum stable rate is determined by transient simulation at successively lower flow rates. The minimum rate for the system is also a function of GLR.

Sand bedding: The minimum velocity is required to avoid sand bedding.

Problem with flow velocities which are too low

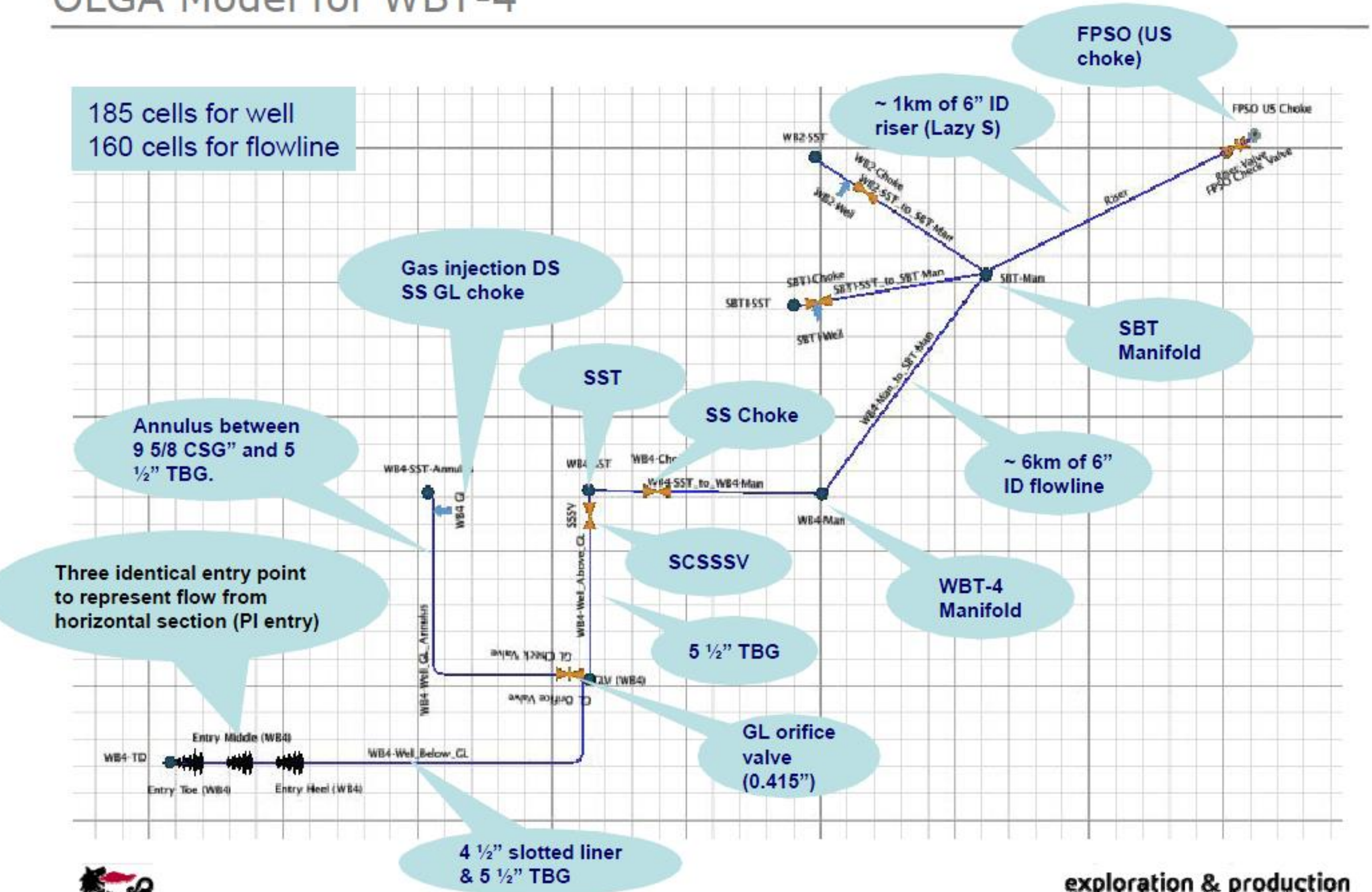
- Liquid holdup may increase rapidly at low mixture velocities.
- Water may accumulate at low spots in the line. This may cause enhanced localized corrosion.
- Low velocities may cause terrain induced slugging in hilly terrain pipelines and pipeline-riser systems.
- The minimum velocity depends on many variables, including: topography; pipeline diameter; gas-liquid ratio; and operating conditions of the line. Roughly a value for the minimum velocity would be a mixture velocity of 5-8 *ft/s*

(note: API recommends 10 ft/s to minimize slugging)

Flow in networks

- A basic approach for networks outlined by Gregory & Aziz (1978) relies on an initial knowledge of the flow from each feed of a gas gathering system, the details of each flowline section (construction, topography etc.) and the pressure and temperature at the outlet (final gathering point).
- Calculations are performed backwards through the system to ascertain the pressure and temperature at each node.
- This approach may require many iterations to study constraints and limitations at supply wells and/or the arrival point.

OLGA Model for WBT-4



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exploration & production

Line sizing

- Unlike single-phase pipelines, multiphase pipelines are sized taking into account the limitations imposed by production rates, erosion, slugging, and ramp-up speed. Artificial lift is also considered during line sizing to improve the operational range of the system.
- The line sizing of the pipeline is governed by the following technical criteria:
  - Allowable pressure drop;
  - Maximum velocity (allowable erosional velocity) and minimum velocity;
  - System deliverability;
  - Slug consideration if applicable.

- Other criteria considered in the selection of the optimum line size include:
  - *Standard versus custom line sizes;*
  - *Ability of installation;*
  - *Future production;*
  - *Number of flowlines and risers;*
  - *Low-temperature limits;*
  - *High-temperature limits;*
  - *Roughness.*

Computational difficulties for pressure drop

- Unknowns:
  - Phase holdups
  - Pipe Perimeters, P_g and P_l , upon which shear stresses act
  - Slip velocity between phases
  - Interfacial friction factors

- Challenges & Complexities:
  - Steady-state vs. transient flow
  - Two vs. three phase flow
  - Non-homogeneous flow
  - Need closure relationships

Mechanistic models vs Multiphase correlations

- Empirical correlations have been used for many years
  - Based on measurements consisting mostly of low pressure, small diameter pipe
  - Extrapolations of correlations to field conditions may result in large errors

- Mechanistic models
  - Developed with experimental data and based on the fundamental mechanisms of multi phase flow
  - Generally proven to extrapolate to field conditions better than the correlations

Two most common multiphase flow models

- OLGA
  - Multiphase steady-state and transient flow
  - Individual slug tracking
  - Compositional tracking
  - Corrosion module
  - FEMtherm module
  - Multiphase pump module
  - Wells module
  - Wax module
  - Hydrate kinetics module
  - Inhibitor tracking module
  - Complex fluid module

- PIPESIM
  - Multiphase steady-state flow
  - Slugging characteristics
  - Network analysis module
  - Well design & production performance analysis
  - Gas lift optimization module
  - Pipeline and facilities design and analysis

Transient Multiphase flow simulator

- Steady state simulators assume that all flow rates, pressures, temperatures, etc. are constant through time. For transient phenomena, such as slug flow, only average values of holdups and pressure drops are calculated.
- Transient simulators show the variations in parameters such as pressure, temperature, and gas and liquid flow rates as a function of time and can model dynamic phenomena such as slug flow.

Characteristics of transient multiphase simulators

- Transient simulators more closely model the operation of pipelines and with more detail than do steady state simulators.
- Transient simulators solve a set of equations for conservation of mass, momentum and energy to estimate liquid and gas flow rates, pressures, temperatures and liquid holdups as a function of time.
- The programs utilize an iterative procedure that ensures a set of boundary conditions (such as inlet flow rates and outlet pressures as a function of time) are met while solving the conservation equations.

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

Model prediction vs Field data

- 24-in. 110 mile gas flowline