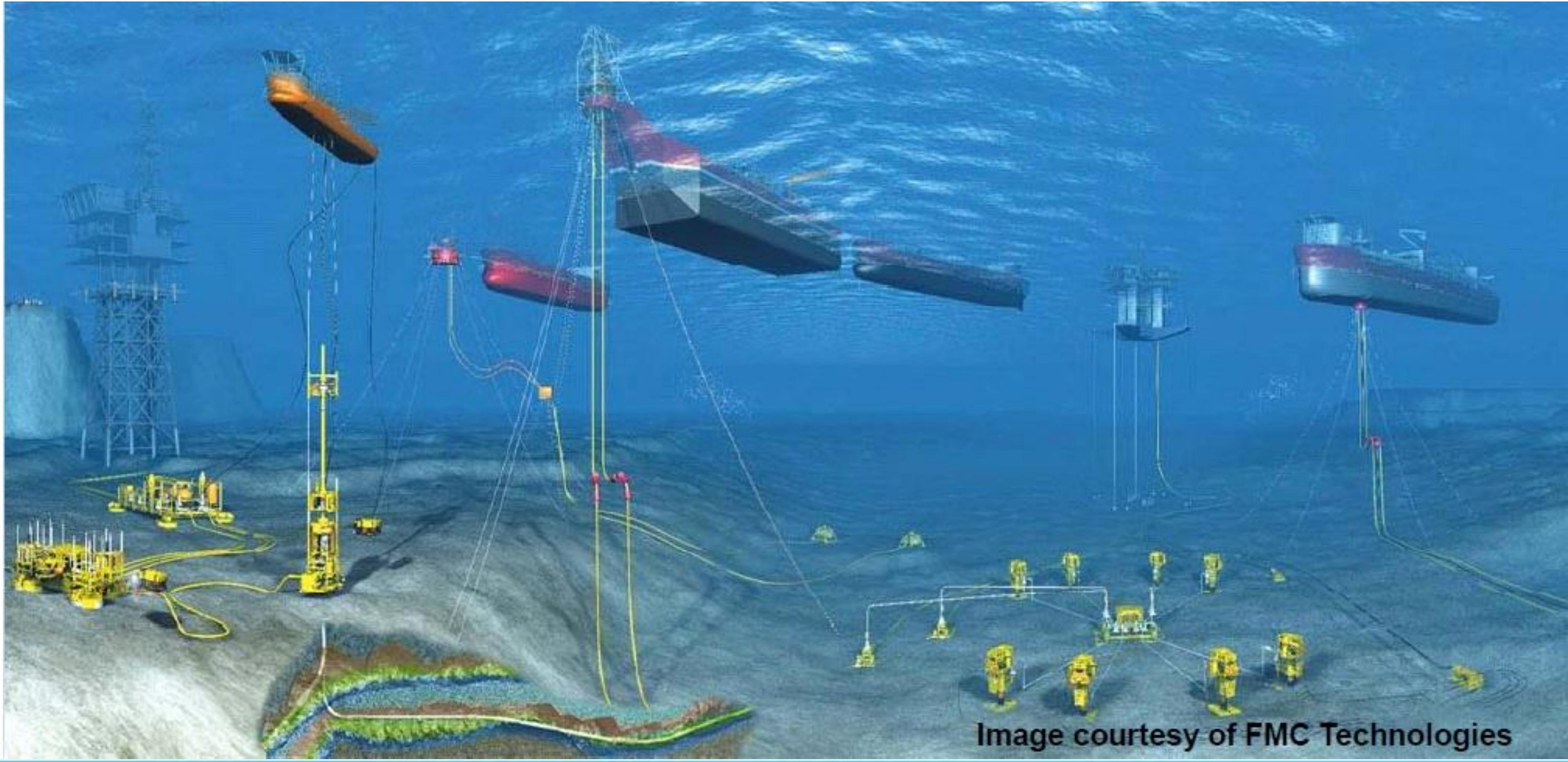
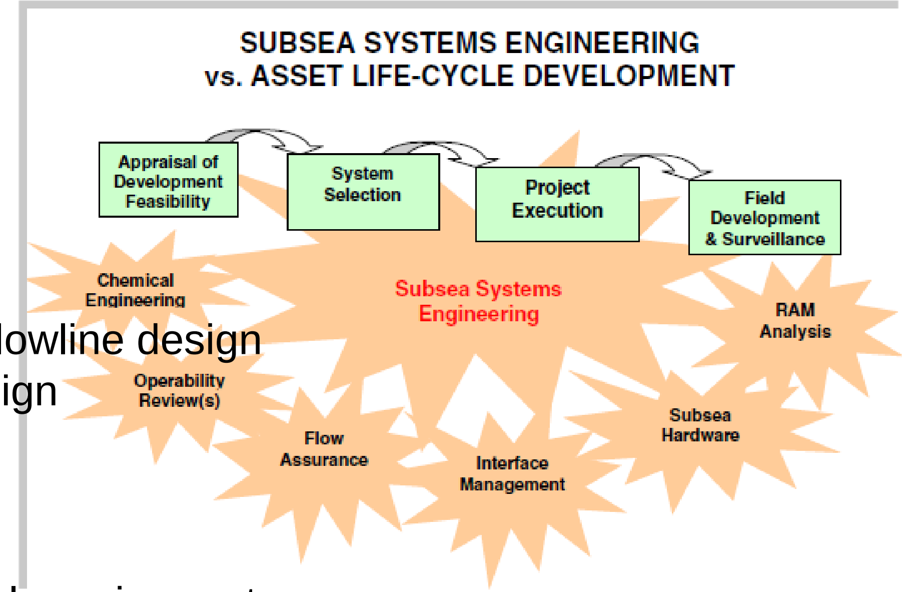


Introduction to Offshore Engineering

Yutaek Seo

Subsea Design Phases



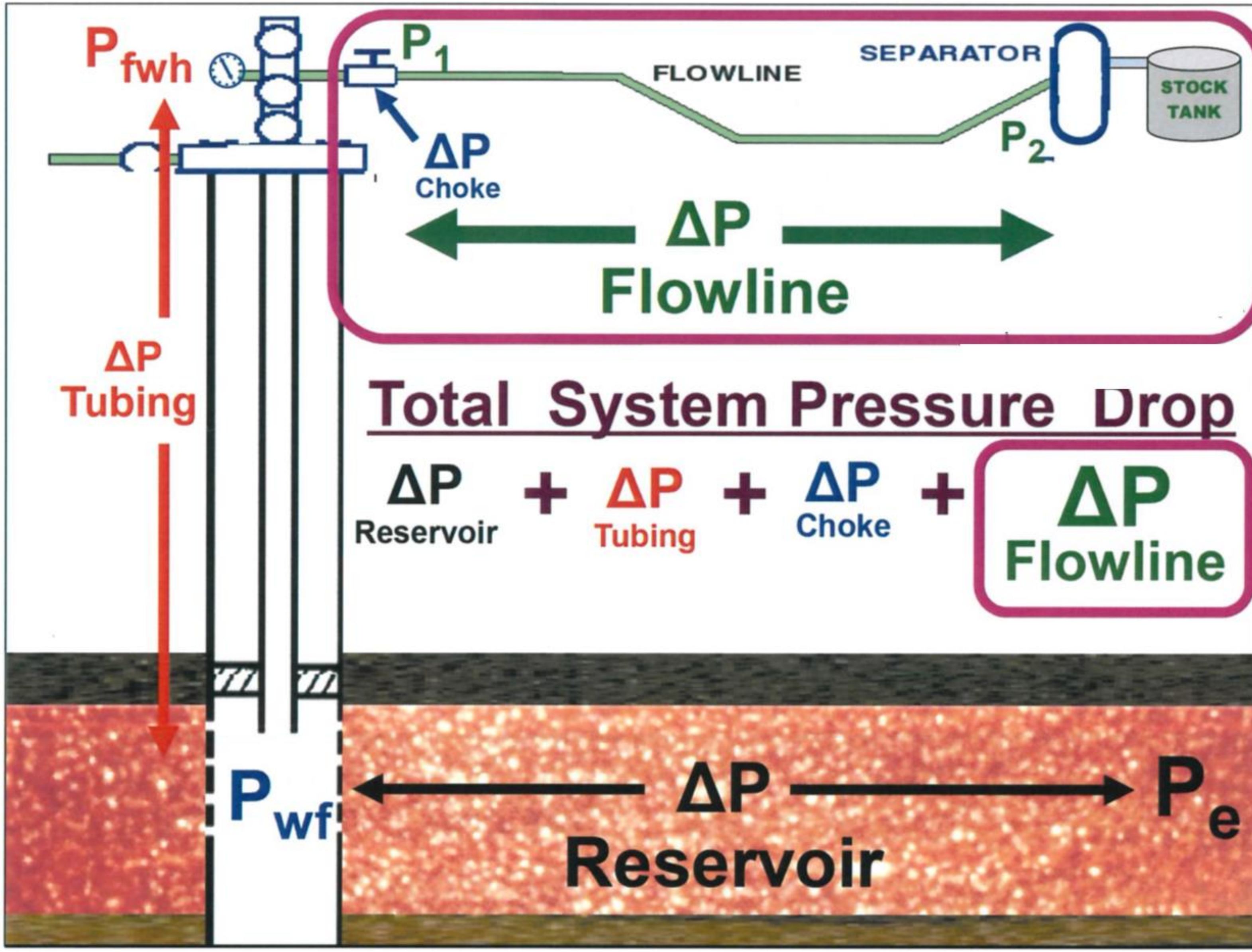
1. Concept Selection/Feasibility
- Compare various flowline routes
- Pipe size and insulation requirements
- Topsides requirements

2. FEED
- Determine most viable flowline route & flowline design
- Chemicals requirements & umbilical design
- Operability & topsides requirements

3. Detailed Design
- Flowline design meets life time functional requirements
- Chemicals requirements & umbilical design
- Operability and topsides design for production & export

4. Operations
- Operator training
- Adjust operating procedures according to reality

Gathering system



Pipeline sizing

- Consider fluid velocity
  - Limit noise / corrosion / erosion
  - Prevent solids build-up in liquid lines
  - Prevent liquid build-up in gas lines

- Contain internal pressure
  - Pipe wall thickness and material strength
  - All piping, connections, valves and fittings must withstand maximum possible internal pressure or be protected by a pressure relieving system

- Minimize pressure drop
  - Minimize pump / compression cost
  - Optimize installed cost

Fluid velocity

- Flowline size – internal diameter

- Pipe internal diameter
  - Larger diameter ➡ fluids move slower
  - Smaller diameter ⟶ fluids move faster

- Line size criteria

(Liquid)

$$d^2 = \frac{0.012\ QBLPD}{v}$$

d: pipe ID, inches,
v: liquid velocity, ft/sec

- Max velocity = 15 ft/sec (Noise and Erosion)
- Min velocity = 3 ft/sec (Solids buildup)

(Gas)

$$d^2 = \frac{60\ QMMSCFDTz}{Pv}$$

d: pipe ID, inches,
T: temperature, °R
z: compressibility factor
P: pressure, psia
v: fluid velocity, ft/sec

- Max velocity = 60 ft/sec (Noise and corrosion)
- Min velocity = 10 ~ 15 ft/sec (Liquid buildup)

Line size criteria – Two phase

- Max velocity = 60 ft/sec (Noise, corrosion, erosion) (50 if CO_2)
- Min velocity = 10 ~ 15 ft/sec (Minimize slugs)

$$d^2 = \frac{\left[11.9 + \frac{R\,z\,T}{16.7\,P}\right] Q_{BLPD}}{1000\,v}$$

R: Gas/Liquid ratio, scf/bbl

- Erosional velocity for two phase

$$Ve = \frac{c}{\sqrt{\rho_{mix}}}$$

Ve: Erosional velocity, ft/sec
ρ:Combined fluid density,lbm/ft3
C:constant between 75 and 200
150~200 for continuous non-corrosive servies
Up to 250 used successfully by industry for non-continuous services

Flowline design pressure

- Maximum allowable working pressure

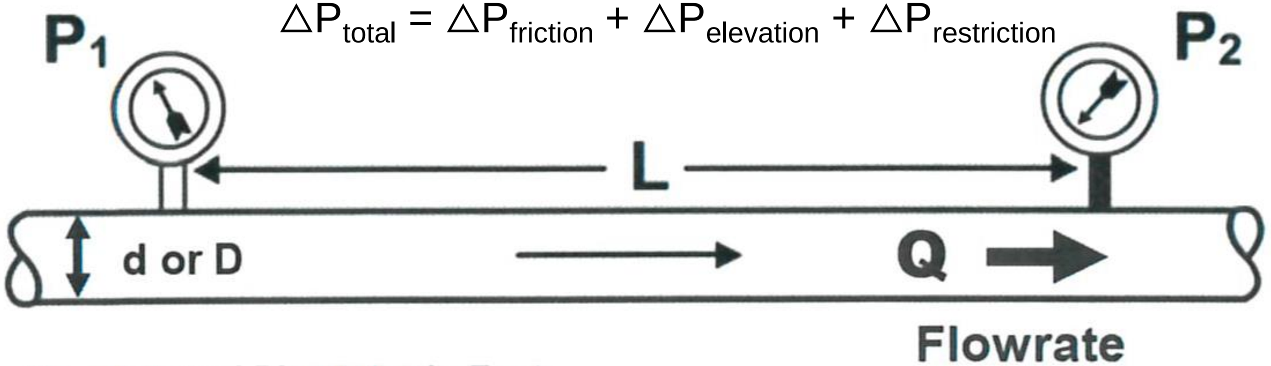
$$P = \frac{2\,S\,t\,F\;E\;T}{d}$$

S: Specified minimum yield strength (psia)
t: pipe wall thickness (inches)
F: Design factor (0.72 or less)
E: Longitudinal joint factor
1.0 seamless
0.8 Fusion/Spiral weld
0.6 Butt weld
T: 1.0 if -20 oF to 250 oF
d: Nominal diameter, inches

Pressure drop vs. Flowrate in oil field flowlines

$$\Delta P = P_1 - P_2$$

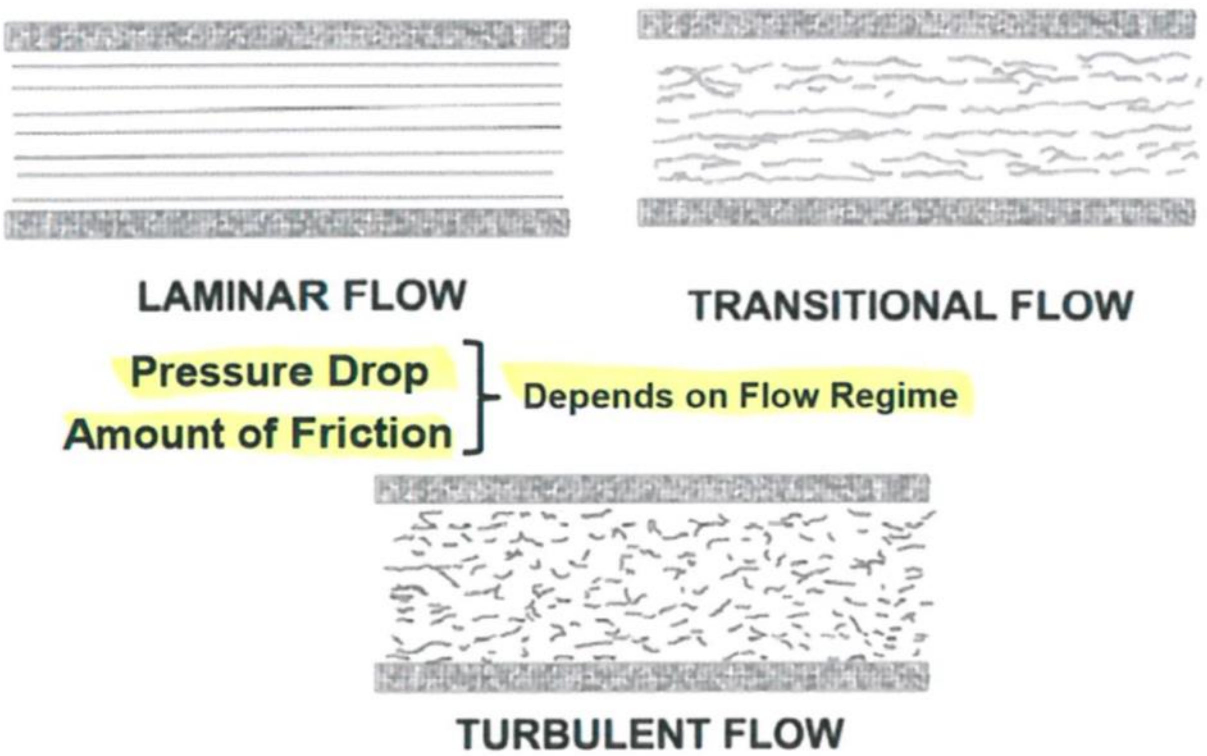
$$\Delta P_{total} = \Delta P_{friction} + \Delta P_{elevation} + \Delta P_{restriction}$$



D = Internal Diameter in Feet

d = Internal Diameter in Inches

Flow regime in pipe



- Gas dominant stream is mostly turbulent
- Flow regime determined by Reynolds number

Reynolds number

- Dimensionless parameter

  : Ratio of Inertia forces to Viscous forces

$$\boxed{R_e = \frac{\rho D v}{\mu_e} \qquad \rho : lb/ft^3 \quad D : ft \quad v : ft/sec \quad \mu_e : lb/ft\text{-}sec}$$

- Re < 2000 = Laminar flow

$$Liquid: Re = 92.1\frac{SG_L Q_{BPD}}{d\ \mu}$$

$$Gas: Re = 20100\frac{SG_G Q_{MMCFD}}{d\ \mu}$$

d: inches, μ: centipoise

Pressure drop: Laminar flow (Re < 2000)

- Liquid

$$\Delta P_{psi} = 0.00068 \frac{\mu_{cp} L_{ft} V_{ft/sec}}{d_{in}^2}$$

$$\Delta P_{psi} = 7.95 \times 10^{-6} \frac{\mu_{cp} L_{ft} Q_{BPD}}{d_{in}^4}$$

- Gas

$$\Delta P_{psi} = \frac{0.040\, \mu_{cp} L_{ft} T_{^\circ R} Z Q_{MMCFD}}{P_{psi} d_{in}^4}$$

No "f_m" since f_m = 64/Re and Re = SG_L Q / d μ

Pressure drop: Transitional and Turbulent

- Liquid

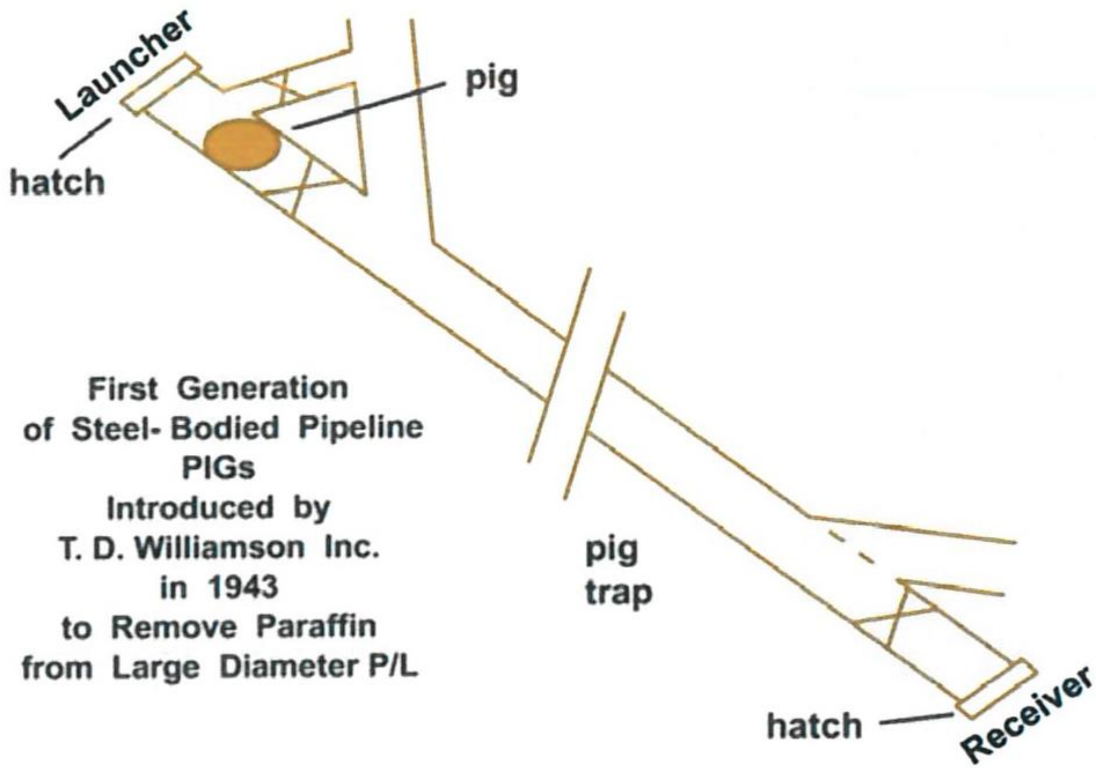
$$\Delta P_{psi} = 11.5 \times 10^{-6} \frac{f_m L_{ft} Q_{BPD}^2 SG_L}{d_{in}^5}$$

- Gas

$$P_1^2 - P_2^2 = 25.1 \frac{f_m L_{ft} Q_{MMCFD}^2 SG_G Z T_R}{d_{in}^5}$$

Pipeline Pigging System

- PIG: Pipeline Internal Gauge



Petroleum Industry PIG

- Pipeline Internal Gauge
  - Check internal condition for pipeline
  - Cleaning: Solids (wax, asphaltene etc)
  - Check or remove obstruction
  - Check for deformation / corrosion / erosion

- Intelligent PIG
  - Measure: Remaining wall thickness
  - Establish: Location and type of defects

- Foam Pigs for cleaning


- Bi-Di pigs: Gauging and Cleaning


Flow Assurance
: Interface with Reservoir Evaluation and Topsides Design

- Production profiles; FWHP, FWHT, WI rates
- Reservoir depth, temperature, and pressure
- Required topside arrival pressure (separator pressure + ~50 psi) and temperature
- Separator and slug catcher capacities
- Capacities and pressure ratings of

  : Export pumps and compressors

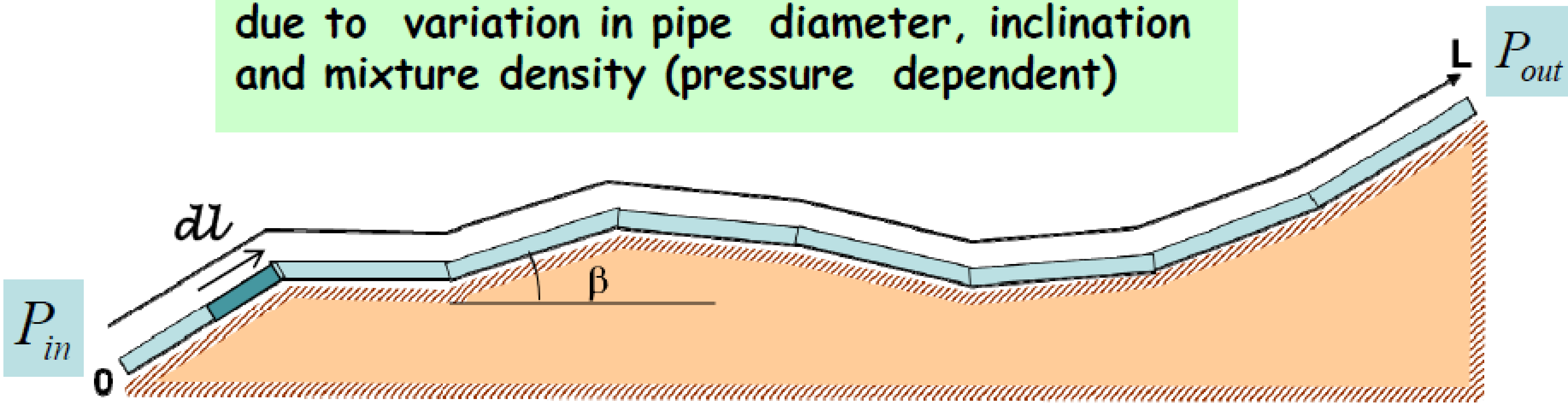
  : Gas lift compressors

  : Chemicals pumps

  : Hydraulic fluid pumps
- Topside piping/equipment – temperature ratings
- Topside storage capacities for oil, diesel, chemicals and water

Pressure drop calculation for long pipeline

The pressure gradient varies along the pipe due to variation in pipe diameter, inclination and mixture density (pressure dependent)



Pressure at exit: $P_{out} = P_{in} + \Delta P$

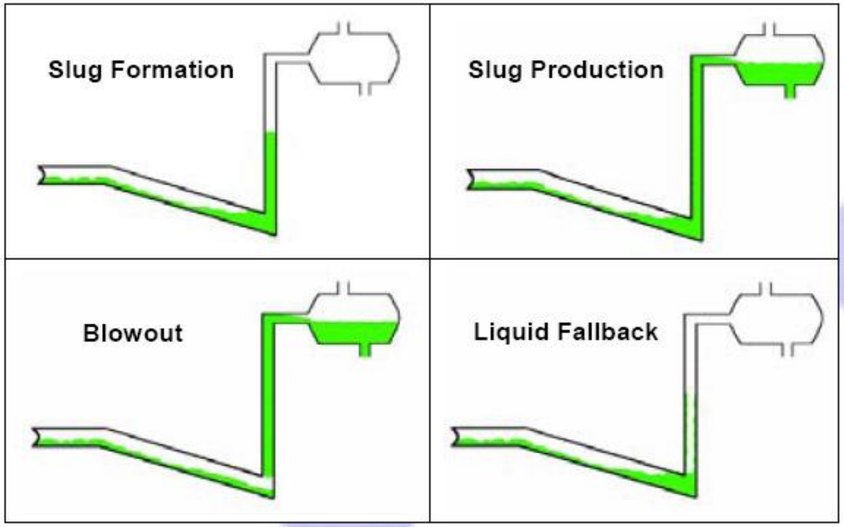
Sum of pressure drop in all pipe segment

Challenge in multiphase flow:

- *The pressure profile depends on the pressure!*
- *Requires iterative numerical solver*

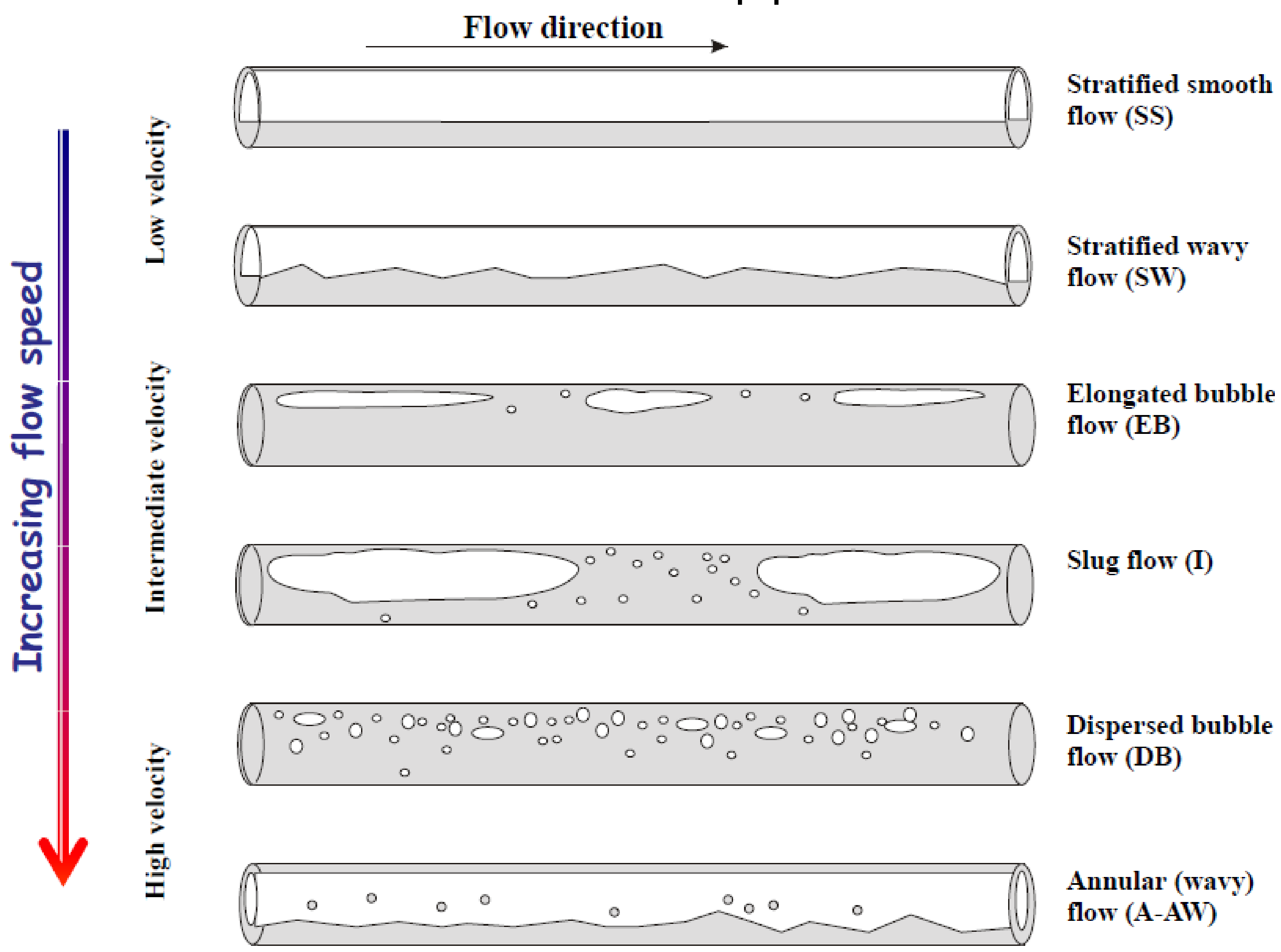
Slugging

- Slugging
  : Periods of low flow followed by periods of high flow (liquid bomb)
  : Occurs in multiphase flowlines at low gas velocities
  : Causes
    - Low fluid velocity
    - Seabed bathymetry
    - Riser type
- Control strategy
  : Increase flowrate
  (playing with topside valve)
  : Slug catcher
  : Gas lift / Gas recirculation

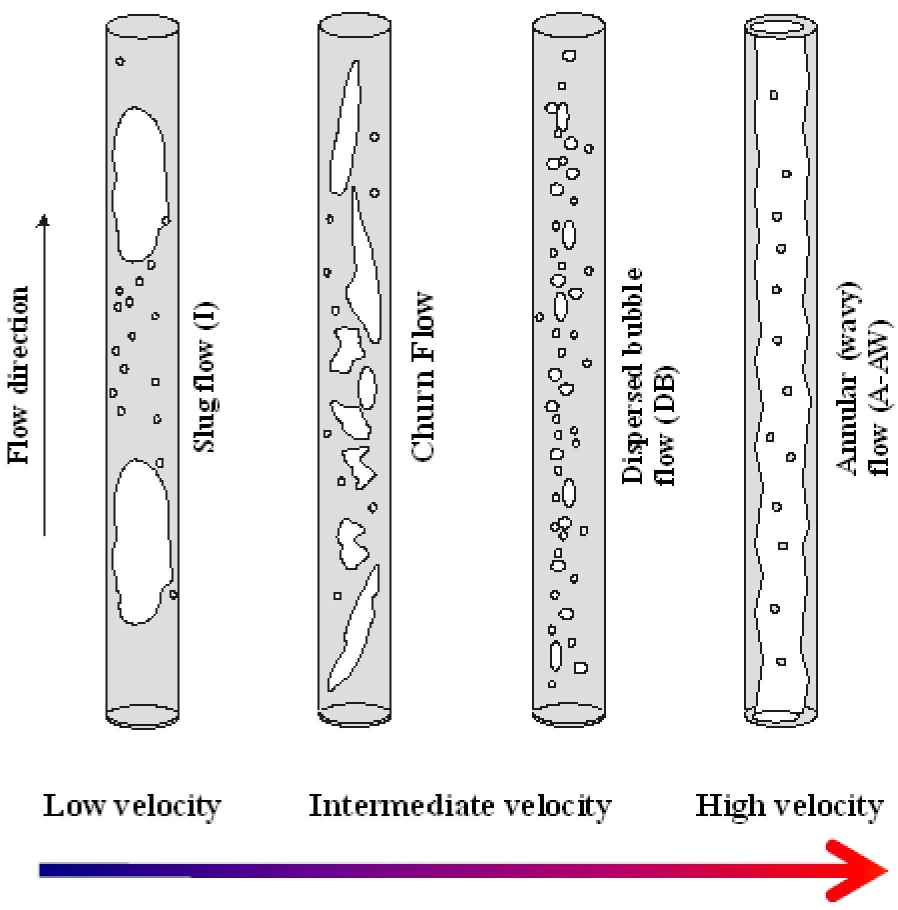


Gas liquid flow regimes

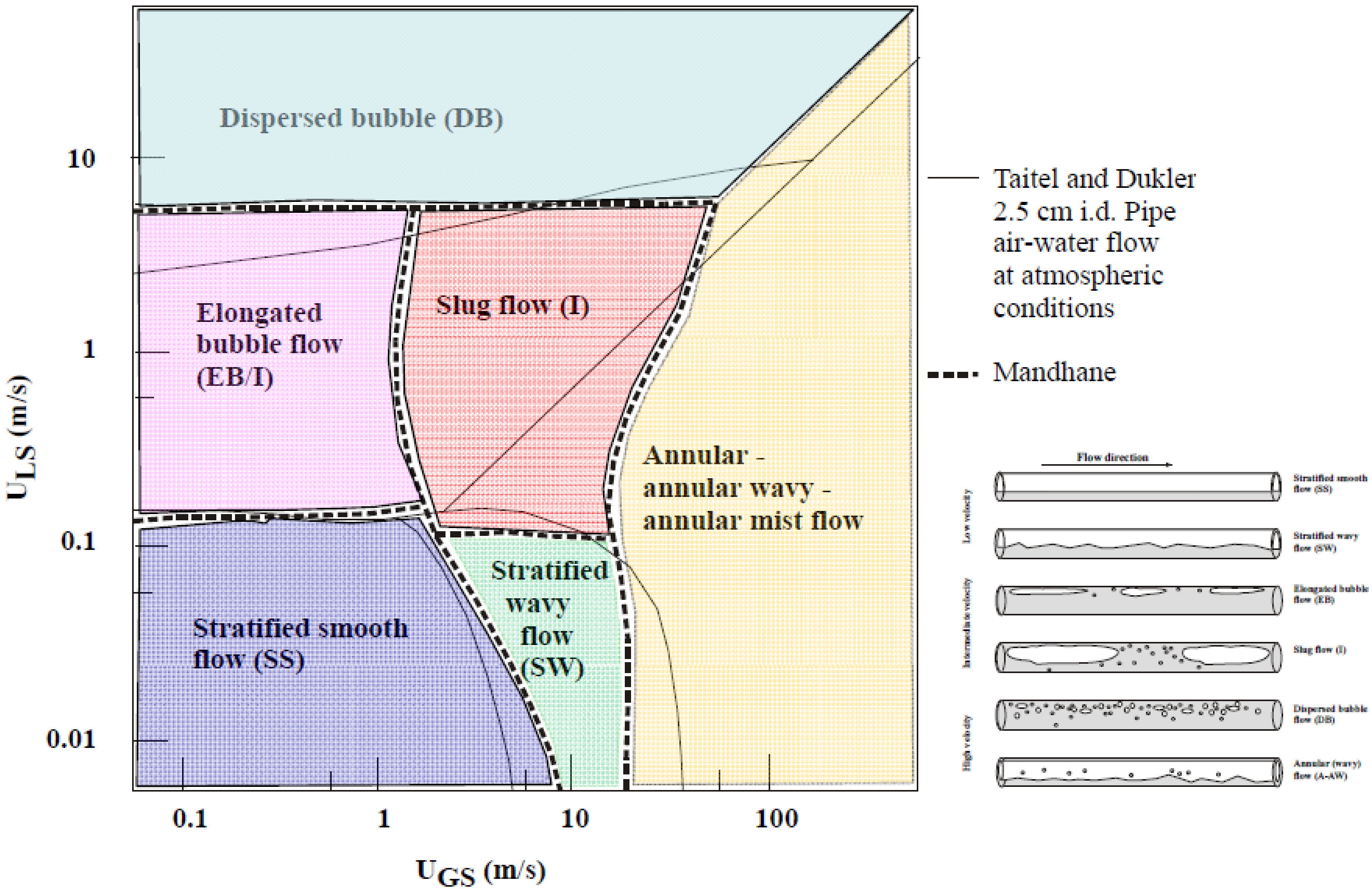
- In horizontal and near horizontal pipelines



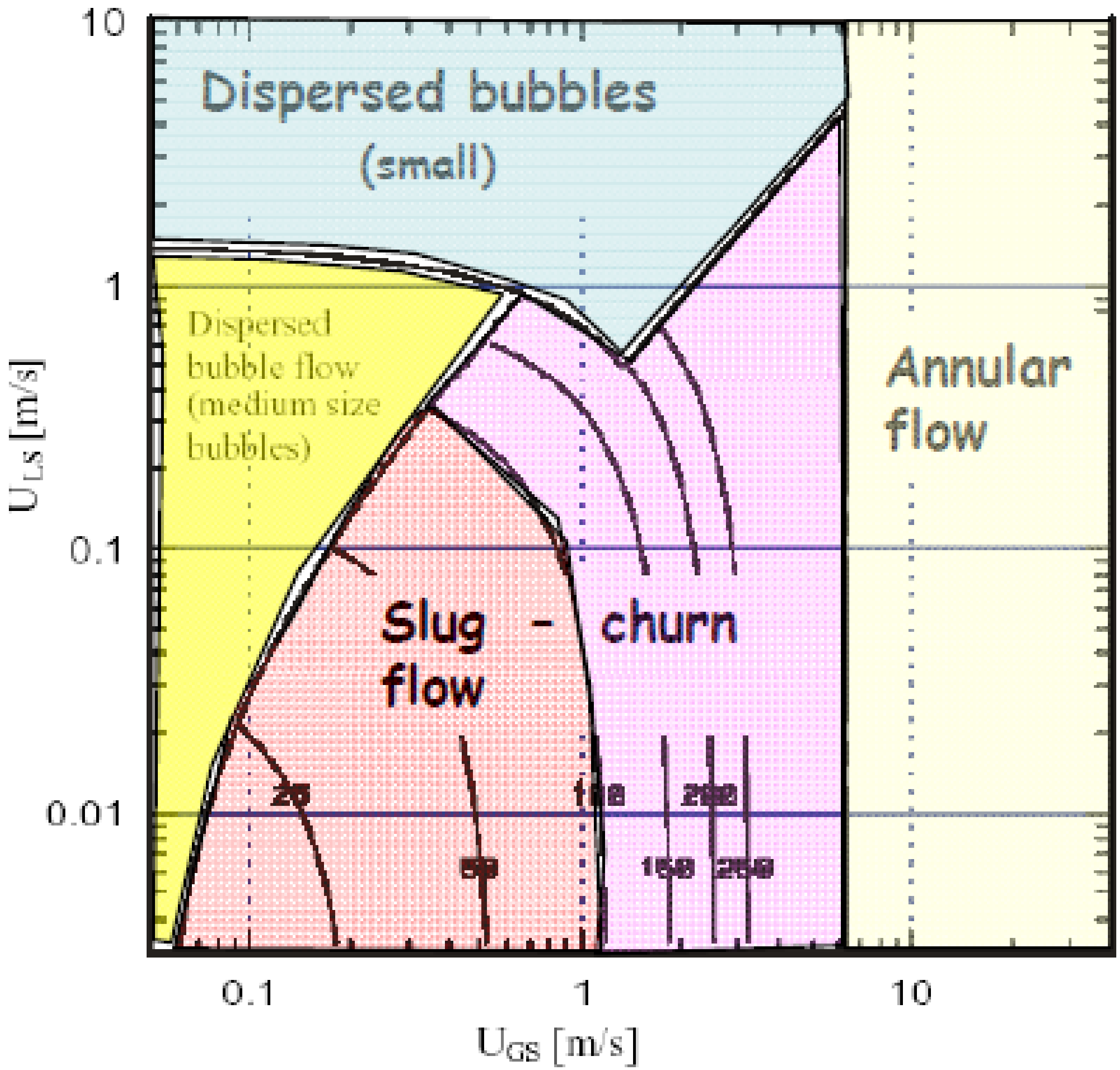
- In up-ward vertical pipeline



Flow regime map – horizontal pipe



Flow regime map – vertical pipe



Hydrate

- Hydrate

  An ice-like solid that forms when

  : Sufficient water is present

  : Hydrate former is present (C1, C2, and C3)

  : Right combination of P and T

- Control strategy

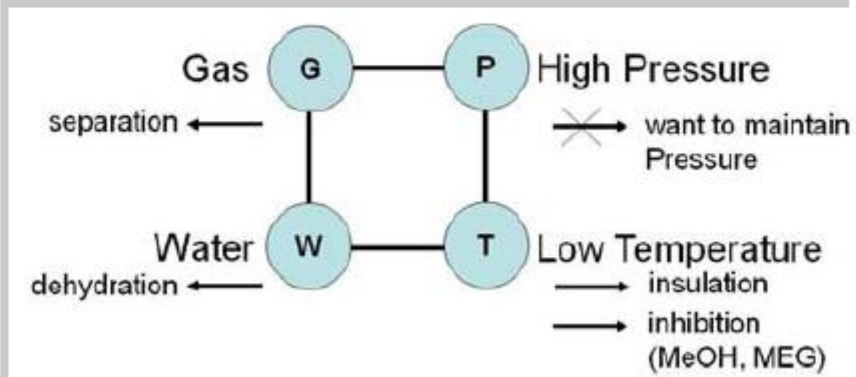
  i) maintaining temperature above hydrate formation conditions (Insulation, DEH, etc)

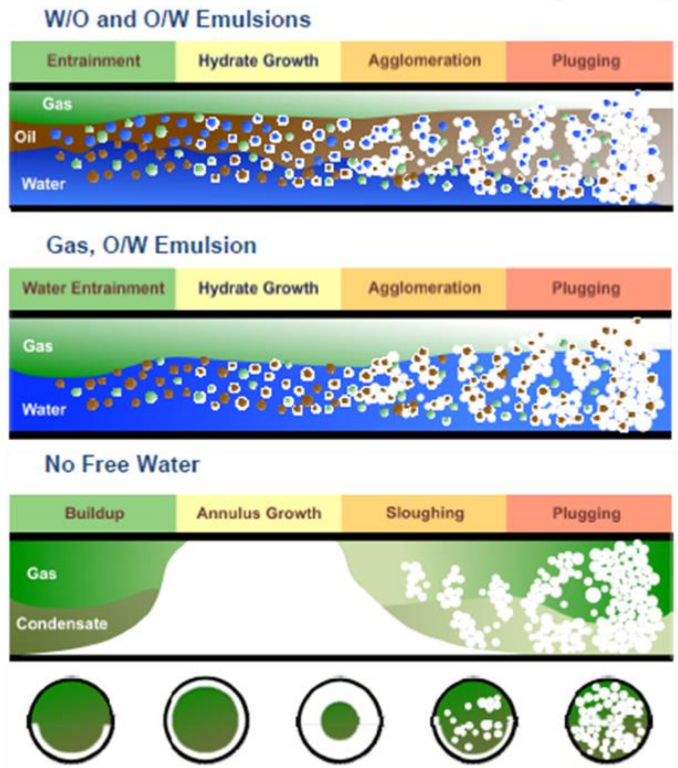
  ii) Decreasing the pressure outside the area of possible hydrate formation (for remediation)

  iii) Removing the water (Subsea processing)

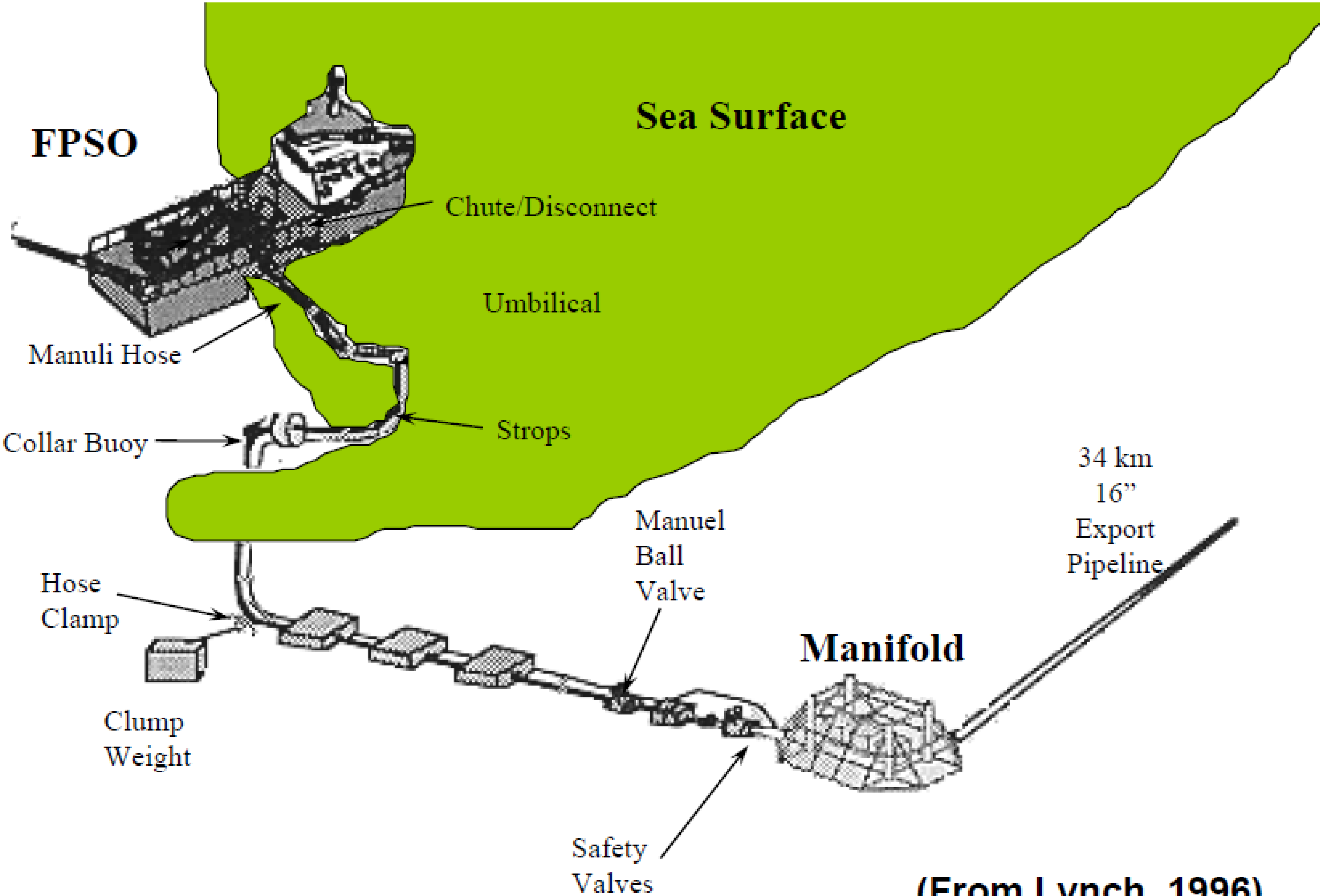
  iv) Continuous injection of chemicals

  : MEG is the most popular hydrate inhibition strategy for long distance tie-back systems





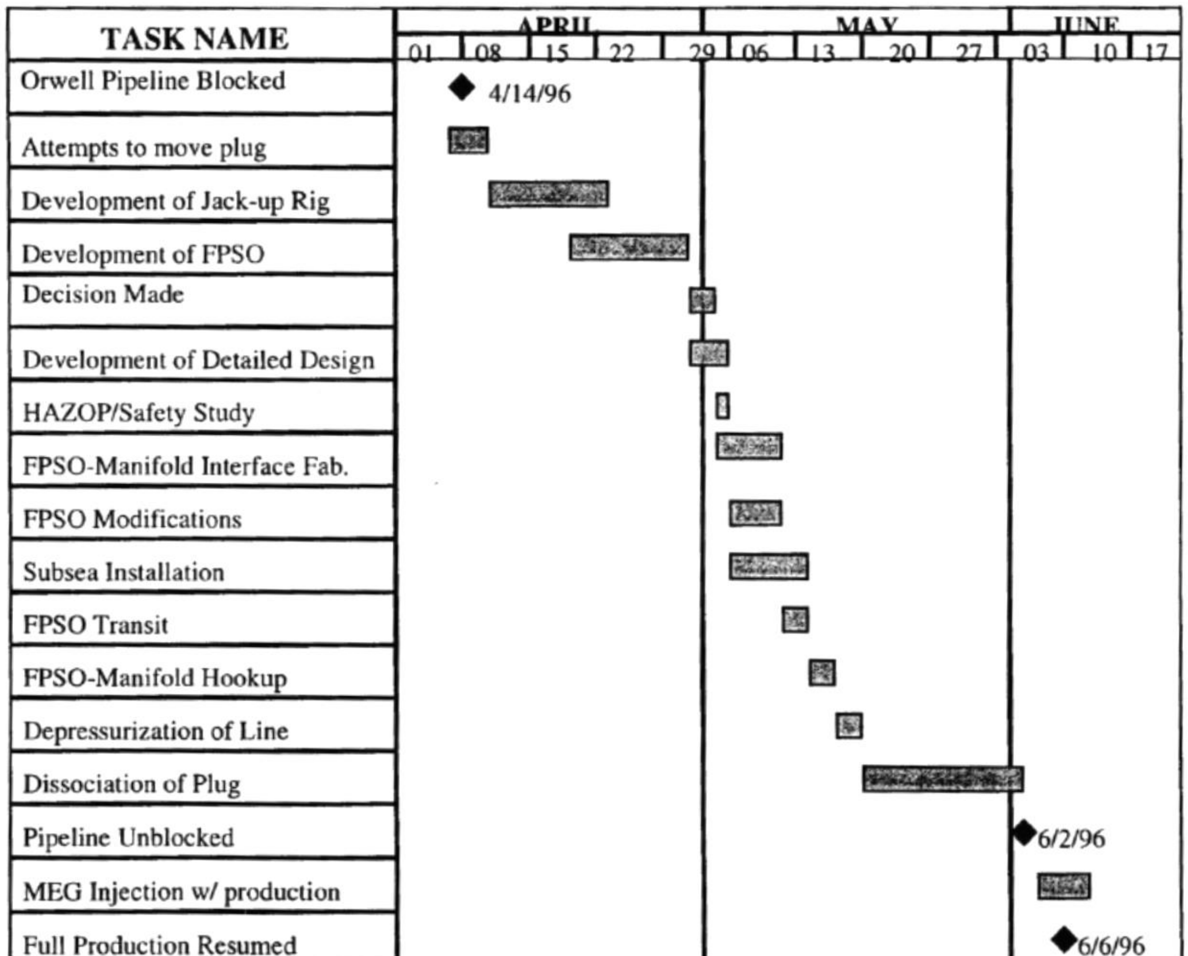
Complete FPSO/Manifold Interface



(From Lynch, 1996)

Figure 71 - Schedule for Complete Plug Remediation

(From Lynch, 1996)



Hydrate mitigation

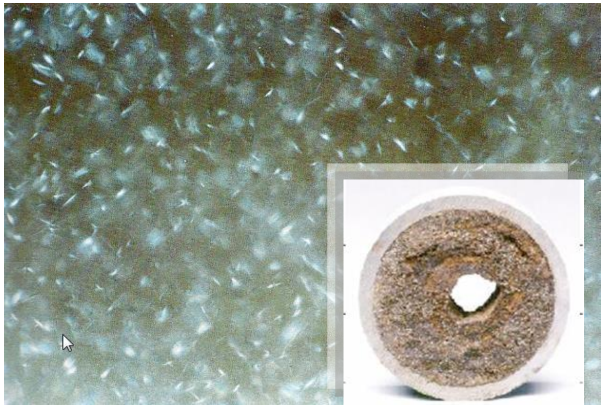
- Insulation
  - Pipe-in-pipe
  - Wet Insulation
- Active heating systems
  - Hot Water
  - Electric
- Subsea Chemicals Injection
  - Methanol, MEG
  - LDHI
- Flowline Pressure Reduction

Thermodynamic Hydrate Inhibitors (THIs)

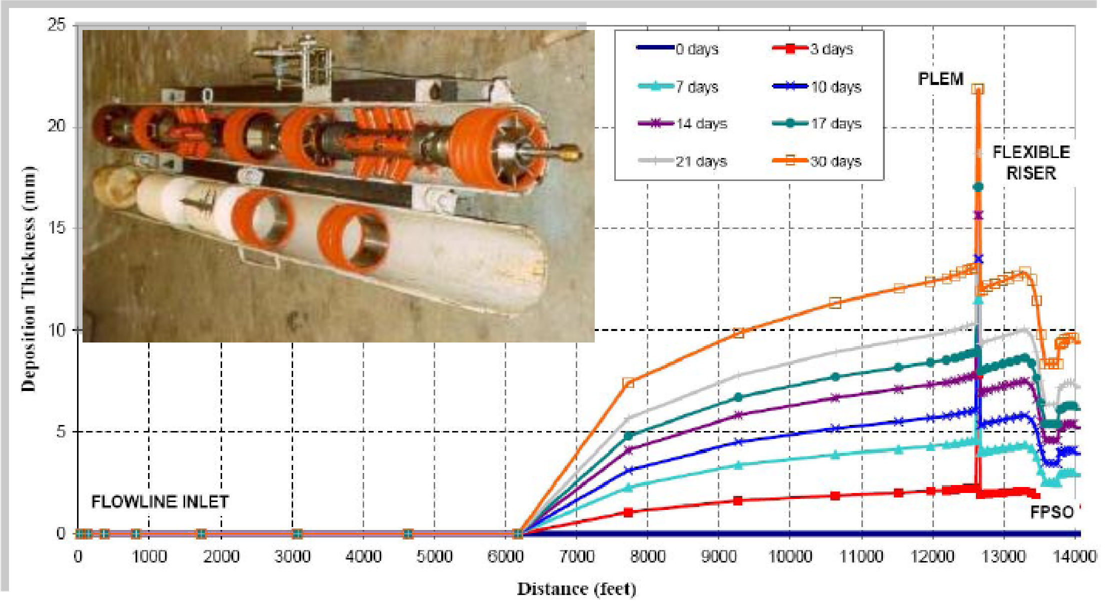
- Methanol
  - : Low cost
  - : Low viscosity
  - : No fouling
  - : More toxic
  - : Too little can be worse than none at low levels
  - : Inefficient to recover
  - : Reduce hydrocarbon sales value
  - : High loss to gas phase
- MEG
  - : Less toxic
  - : Under-treating not as bad
  - : Efficient to recover
  - : Does not affect hydrocarbon value
  - : Loss to gas phase negligible
  - : High viscosity
  - : Salts precipitation
  - : Fouling by salt deposition

Wax

- Paraffinic hydrocarbons (candle?)
  : A solid paraffinic hydrocarbon which precipitate from a produced fluid
  : Forms when the fluid temperature drops below the Wax Appearance Temperature (WAT)
  : Melts at elevated temperature (20°F above the WAT)

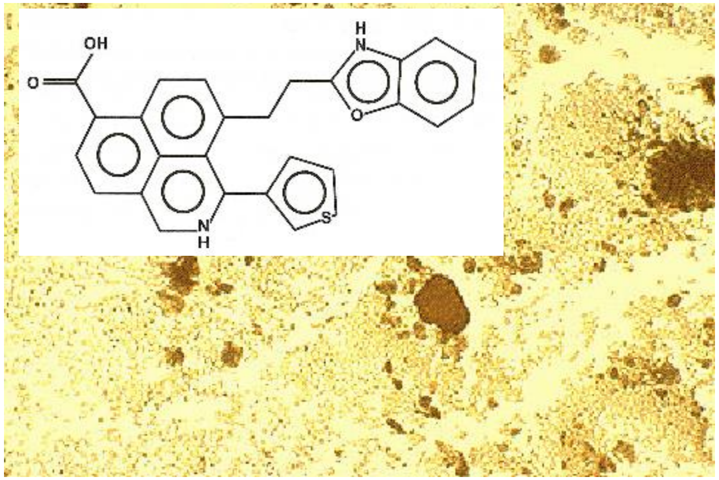


- Control strategy
  : Rate of deposition can be predicted to calculate pigging frequency
  : Flowline insulation
  : Wax inhibitor
  : Major factors
  - WAT
  - Fluid temperature
  - Overall U-value
  - Deposition rate



Asphaltenes and Scales

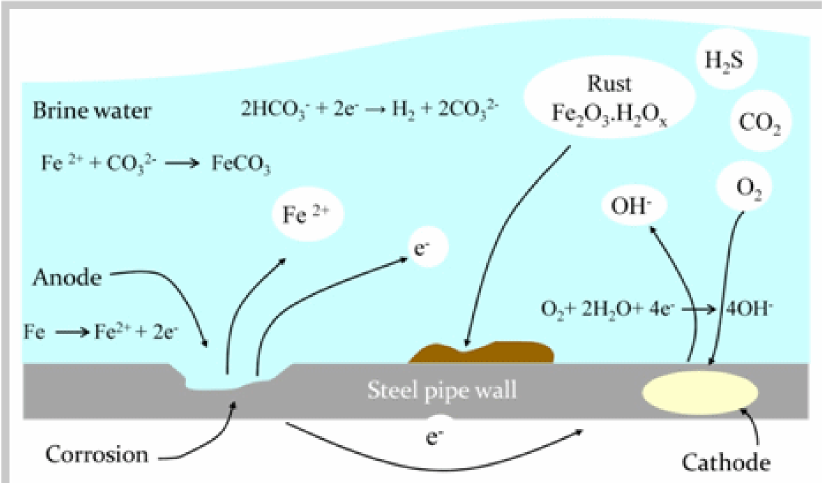
- Asphaltenes
  : The heavy polar aromatic fraction
  : Resulting blockage and formation damage
  : The main causes are
    - A decrease in the system pressure
    - Mixing of incompatible crude oils
  : Require asphaltene inhibitor injection

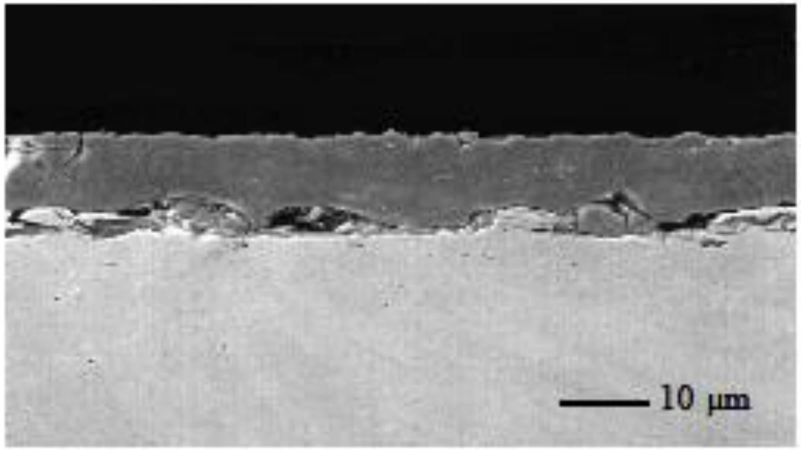


- Scales
  : The carbonates or sulphates of calcium, strontium and barium
  : $MgCO_3$, $CaCO_3$ scaling issues in the MEG system
  : Require scale inhibitor injection

Corrosion

- Loss of metal
  : Metal loss caused be corrosive water
  : Fe = Fe^{++} + 2e-
  : Variables
    - Material
    - H_2S and CO_2 level in fluids
    - Water composition
- Control strategy
  : Alter chemical environment
    - Oxygen scavengers
    - Sulfide scavengers
  : Alter reactive surface of metal
    - pH control to form protective film
    - Corrosion inhibitors
    - Polymeric liners to flowlines





protective iron carbonate film formed at high pH (right).

Example treating chemicals properties and levels

Treating Chemical (& Injection location)	Viscosity at 40 oF (cP)	Density at 14.7 psia (g/cc)	P50 Treatment levels	
			(ppm-V)	basis
Paraffin Inhibitor (at tree)	4.1@ 14.7 psia 8.2 @ 10,000 psia	0.879 @ 60 oF	150	Oil
Scale Inhibitor (down hole)	37.8 @14.7 psia 41.5@10,000 psia	1.324@ 77oF	20	Water
Asphaltene Inhibitor (downhole)	12.4 @ 14.7 psi 35.3 @ 10,000 psi	0.926@ 60oF	250	Oil
Corrosion Inhibitor (at tree)	83.1 @ 14.7 psia 187.7 @ 10,000 psia	0.999@ 70oF	25	Oil + Water

Note: Treating chemicals from different suppliers (and different formulations from the same supplier, for the same function) can have greatly different physical properties and treatment levels.

Summary – Flow Assurance

- Simulation of subsea systems becomes an important discipline for design and operation of offshore platfoms
- It demands comprehensive understanding of multiphase flow and solid deposition.
- The simulation results are linked together in matrix form, thus stage work process is required.

Fluid characterization	Hydraulic analysis	Thermal analysis	Solid deposition	Production facilities
PVT data 확보 PVT modelling	Pipeline ΔP Inlet P - Arrival P	Steady-state Transient	Hydrate, Wax Asphaltene, Scale, corrosion, erosion	Subsea production Topside processing
Thermodynamic model : 상태방정식 : 모델 파라미터 소프트웨어 : PVTSim : Multiflash	: Topside 도달 압력, 유량. : liquid holdup 계산. : Reservoir 압력. : manifold 압력 최대 생산기간 예측.	: 파이프라인 단열재 재질 및 두께 선정. : Topside 도달 온도 계산.	: 저해제 주입량 및 주입 위치, 압력 선정 - MEG/MeOH - Wax, corrosion, asphaltene inhibittors.	: 파이프라인 내경 선정 : Slug catcher 설계 : MEG 재생 공정 spec : Inhibitor injection station

Thank you!