Chapter 8: Flow assurance management in production systems

Flow assurance consists in ensuring uninterrupted flow of hydrocarbon streams from the reservoir to the point of sale according to production plan. Flow assurance is particularly relevant for deep subsea systems with relatively long transportation distances (5-150 km) and low surrounding temperatures. In this type of systems if there is a problem intervention and remediation has to be done remotely and it is usually time consuming and very expensive.

Flow assurance focuses on three main aspects:

1. Avoid flow restrictions (excessive pressure drop, blockage or intermittent production).
2. Safeguard the structural integrity of parts of the production system from damages caused by internal flow.
3. Maintain the functionality and operability of components in the production system.

There are multiple issues that are typically addressed in flow assurance:

- Formation and deposition of wax.
- Formation of hydrates.
- Formation and accumulation of scale
- Flow induced vibrations (FIV)
- Asphaltene formation and deposition
- Slugging
- Erosion
- Emulsion
- Corrosion
- Pressure surges during shutdown and startup.

Fig. 1 shows where these issues usually occur in the production system.

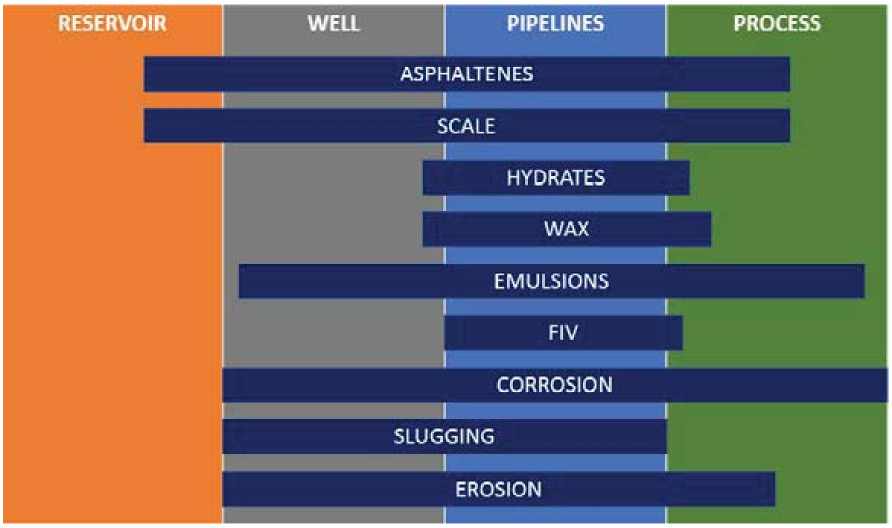
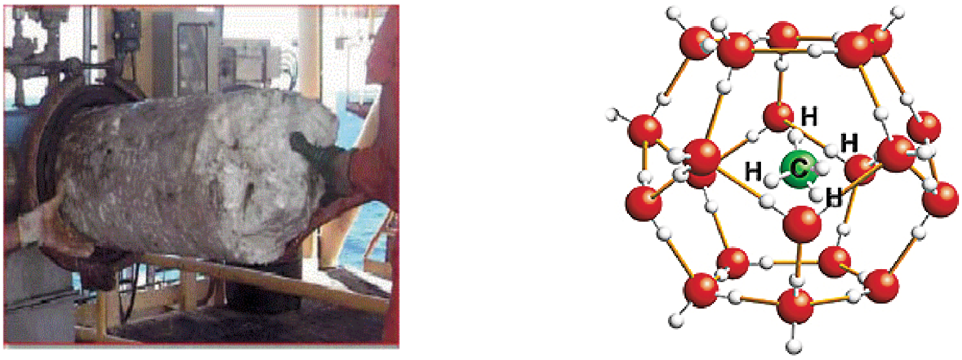


Fig. 1. Flow assurance problems and their typical location in the production system

HYDRATES

Hydrates are solid substances where water molecules (in liquid phase) form a cage-like structure that hosts small (< 9 Å diameter) molecules (Fig. 2). The small molecules are usually methane, ethane, propane, butane, carbon dioxide, nitrogen. The cage-type structure is formed due to hydrogen bonding of water molecules (the water molecule tends to spacially create two positives and a negative pole).



(a) **(b)**

Fig. 2. A) appearance of a hydrate plug, b) molecular structure of a methane hydrate

Hydrates contains a much higher proportion of water than the hydrocarbon component. For example a methane hydrate (called methane clathrate) with molecular formula $4CH_4 \cdot 23H_2O$ (MW = 478) has a molar proportion of 85% (23/27) water and 15% (4/27) methane.

However, this doesn't necessarily indicate that they contain small amounts of gas. For example one cubic meter of methane clathrate (of an approximate density of 900 kg/m^3) contains 1.88 (900/478) kmoles of hydrate, of which there are 7.53 (1.88*4) kmoles of methane. 7.53 kmoles of methane at standard conditions correspond to 178.4

Sm^3! ($V_{SC}=n_{moles}\cdot R\cdot T_{SC}/p_{SC}$). For a cubic meter to contain the same amount of gaseous methane at standard temperature, it would have to be compressed at 180.4 bara (p= 7.53 kmol·R·T_{SC}/1 m^3).

Hydrates form only if ALL following ingredients are present:

- Free water (in liquid phase)
- Small hydrocarbon molecules
- Particular range of pressure and temperature.

An example of the hydrate formation region is shown in Fig. 3. The actual line depends mainly on the fluid composition, but, as a rule of thumb, it happens at high pressure and low temperatures. For example at a pressure of 12 bar, the hydrate formation temperature is 4 C.

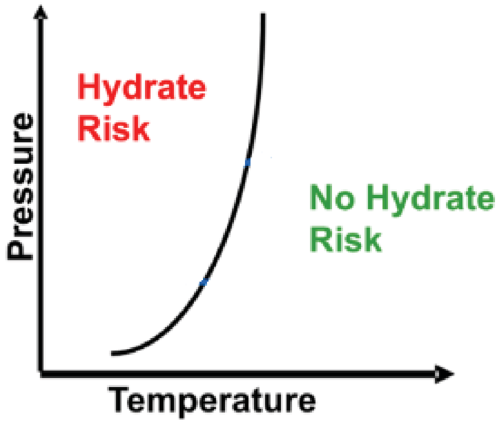


Fig. 3. Hydrate formation region

The hydrate formation line can be predicted by empirical expressions (that are a function of the specific gravity of the gas), or using equilibrium calculations with an Equation of State. Hydrate equilibrium calculations resemble to Vapor Liquid equilibria by finding p and temperature conditions that make equal the chemical energy of the component in the hydrate phase and liquid and gas phases.

Consequences of hydrates for flow assurance

If the pressure and temperature of the fluid flowing along the production system falls inside the hydrate formation region, hydrates will start to form. Hydrates usually form at the liquid-gas interphase where free water and small hydrocarbon molecules are in contact. The mixing and turbulence of the flow further increases the contact between the two thus causing the formation of more hydrates. Hydrates then start to agglomerate until they eventually plug the pipe (Fig. 4).

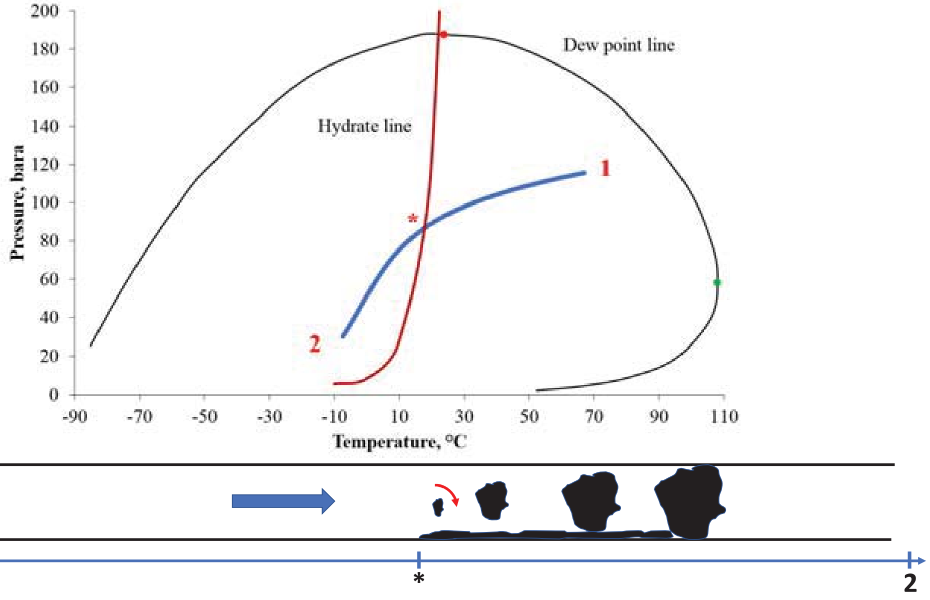


Fig. 4. **Evolution of p and T of the fluid when flowing along the production system**

Hydrates can also form when the production is stopped and the stagnant fluid begins to cool by transferring heat with the environment.

Management

The traditional strategy to manage hydrates is to avoid their formation. There are two main techniques commonly used to prevent the formation of hydrates:

- **Keep the fluid conditions out of the hydrate formation region.** This is done mainly by reducing the rate of temperature drop of the fluid (reducing the lateral spread of the blue line in Fig. 4). This is achieved in practice by two methods: better insulation or electrical heating of the pipe.

Please note that insulation works effectively for a flowing system, but when production is stopped, usually some other control method must be used as the fluid will eventually cool down during a long period.

Electrical heating is usually not cost effective for long transportation distances.

- **Reduce the hydrate formation region.** The equilibrium pressure and temperature of hydrate formation can be affected by adding liquid inhibitors (typically Mono-ethylene-glycol MEG, Tri-ethylene-glycol TEG or methanol MEOH) to the water phase. Inhibitors interfere with the formation of hydrogen bonds by keeping water molecules apart. As a consequence, the hydrate formation line will be shifted to the left (as shown in Fig. 5).

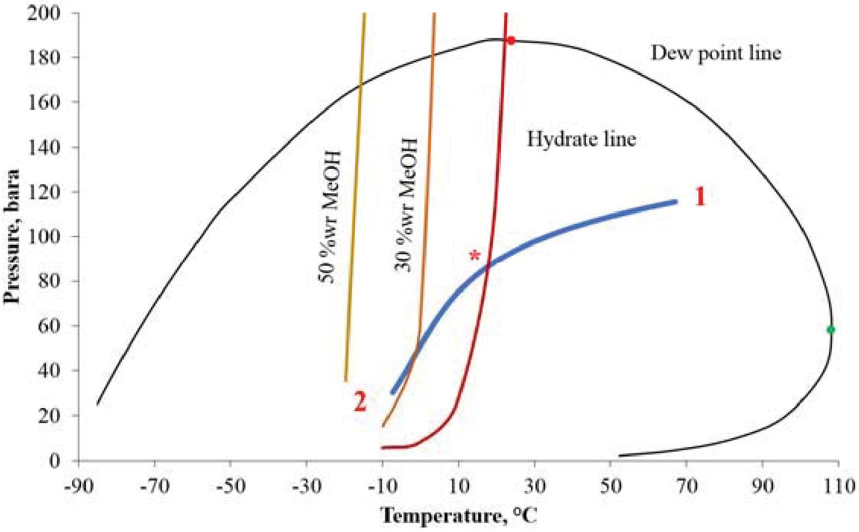


Fig. 5. Effect of inhibitor injection on the hydrate line

Typical concentrations of inhibitors used are 30-60 in weight %. For example the Snøhvit field has a Water Gas ratio of 6 E-6 Sm^3/Sm^3. The plateau production of the field is 20 MSm^3/d, thus it produces around 120 Sm^3/d of water, or, equivalently, 120 000 kg/d of water. If we assume that the inhibitor concentration used is 50 in weight %, then this gives 120 000 kg/d of MEG that must be continuously injected on the field. MEG is usually reclaimed in the processing facilities. Otherwise, it will represent a daily cost of 60 000 – 180 000 USD (assuming a MEG cost between 0.5 – 1.5 USD/kg).

Please note that the inhibitor must be present in the water phase for it to be effective, thus evaporation to the gas phase has to be taken into account when estimating the required amounts of inhibitor.

Inhibitors are also injected when preparing to shut down production, to make sure hydrates will not form due to the cooling of the fluid.

During the last years, many experts have proposed to use a less conservative hydrate control strategy where we allow hydrates to form, but impede their agglomeration and carry the slurry together with the production fluids. This can be performed by injecting special types of chemicals, or by using cold flow. However, up to date there are limited field cases where this type of management is performed.

SLUGGING

Slugging consists on intermittent flow of gas and liquid in the production system (Fig. 6).

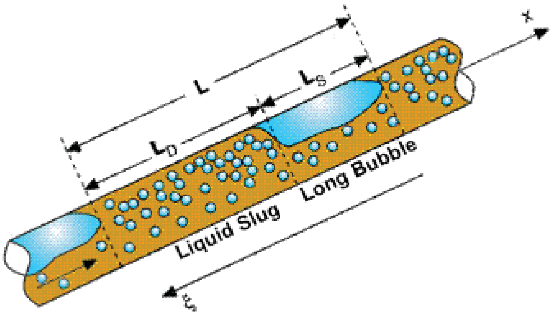


Fig. 6. Slug in a pipe section

There are two main types of slugging:

- Hydrodynamic slugging: It occurs spontaneously at a particular combination of flow velocities of liquid and gas and it depends strongly on the fluid properties and pipe inclination. As an example, Fig. 7 shows the flow pattern map for a horizontal pipe and certain fluid properties. There is a particular combination of operational velocities where the flow will arrange itself in a slug flow configuration.

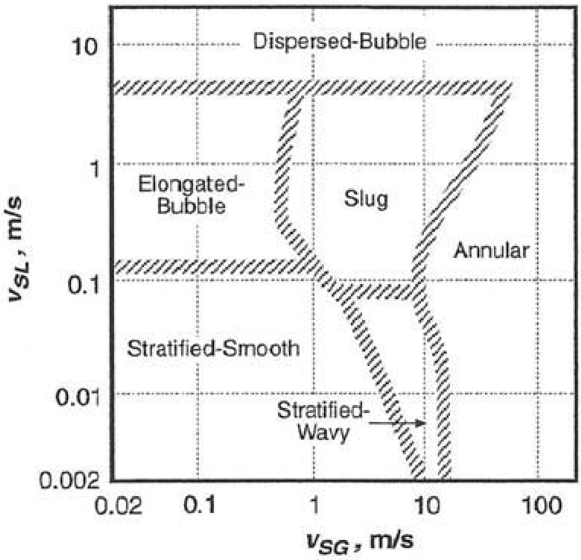


Fig. 7. Flow pattern map for an horizontal pipe (After Mandhane et al. 1974)

- Terrain slugging: Terrain slugging is mainly due to cyclic accumulation of liquid in the production system (especially in lower points). This happens in undulating well trajectories, transportation flowlines with varying topology of the seabed and in risers.

An example of slugging in a s-shaped production riser is shown in Fig. 8. Liquid accumulates in the lowest pipe section and blocks the flow of gas (a). The liquid level starts increasing and the gas pressure in the horizontal line also increases (b). Eventually, the liquid floods the second floor of the riser (c). Gas pressure increases until it is sufficient to flush out almost all the liquid in the riser (d).

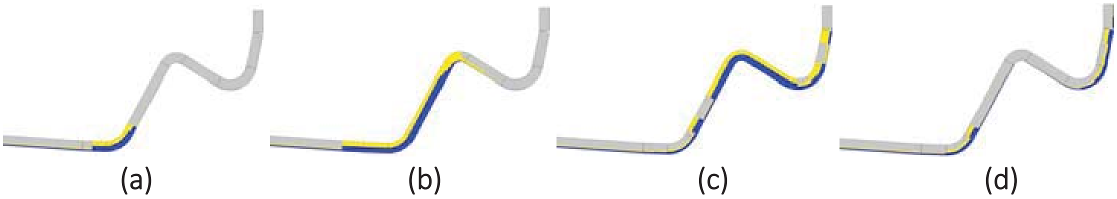


Fig. 8. Stages of severe slugging in an S-shaped riser.

Consequences of slugging

The main consequence of slugging is that production rates and pressures will fluctuate in time which is often detrimental to the proper operation of the downstream processing facilities. In gravity separators for example, a sudden inlet of liquid might increase significantly the liquid level, causing liquid carryover, activating the warnings for high liquid level and even triggering a shutdown alarm.

Slugging also causes vibration in flowlines, manifolds, risers which can develop in structural damages due to elevated stress levels and fatigue.

Management

Slugging can be, to some extent, predicted during the design phase of the field using commercial multiphase flow simulators such as Leda, Olga and FlowManager. If it is detected and it has high severity (long slug lengths, frequencies that coincide with the natural frequency of the structure, relevant pressure fluctuations), potential solutions are to change the routing of the flowline, refill or dig some sections of the seabed that can cause liquid accumulation or changing the pipe diameter. Smaller pipe diameters increase the gas velocity, increasing the drag of the gas on the liquid thus reducing the liquid deposition. However, too small pipe diameters also cause higher pressure drops that reduce overall production rates.

If slugging is occurring in an existing production system, some approaches that have been used successfully in the past are to apply gas lift in the riser base or to use the topside choke to change dynamically the backpressure on the line and “control” the slug.

SCALING

Scaling is the precipitation of minerals compounds (constituted by Na, K, Mg, Ca, Ba, Sr, Fe, Cl) from the produced water and their deposition on pipe walls. Scale occurs when the solubility of the minerals in the water decreases due to changes in pressure and temperature, due to mixing of waters of different sources, injection of CO_2. Minerals usually deposit on surface areas that are rough or have irregularities (e.g. valve components).

(a) (b)

Fig. 9. Scale accumulation in a a) pipe, b) choke

There are two main types of scales that usually occur in production systems:

- Carbonate scales. These scales are formed when CO_2 dissolved in the water disassociates in carbonate ions CO_3^{-2} and join with some of the aforementioned minerals (typically calcite $CaCO_3$, Iron carbonate $FeCO_3$). Their precipitation is mainly due to reduction in pressure (due to flow in restrictions, valves, chokes) or increases in temperature. This type of scale can be removed with acid.
- Sulphate scales: These scales are formed by the sulphate ion SO_4^{-2} that is present in seawater (Barite $BaSO_4$, Gypsum $CaSO_4 \cdot 2H_2O$, Anhydrite $CaSO_4$, Celestite $SrSO_4$). It precipitates out of solution when waters from different sources are mixed (e.g. seawater used for injection and production water from the aquifer or formation). The pressure has little influence in the precipitation, but the increase in temperature can reduce further the solubility. This type of scale must be removed mechanically.

Consequences

Scaling causes gradual blockage of the flow path and loss of functionality in production equipment (Subsurface safety valves, chokes).

Management

Studies are usually performed on the produced water to determine if it will be prone to form scale at the pressure and temperature conditions encountered in the production system. Moreover, special attention must be payed to situations where there is mixing of water from different sources, CO_2 injection.

Scaling is usually avoided by using chemicals (scale inhibitors) that attach themselves to the scale ions and impede growth. Coating can help to prevent deposition on the surfaces but when damaged (e.g. due to erosion) their effectivity is reduced dramatically.

If scale forms in a component of the production system, the removal technique depends on the type of scale. Carbonates can be removed by acid injection and sulphates can only be removed mechanically.

EROSION

Erosion is the gradual damage and loss of material from the wall of components of the production system (valves, pipes, bends, etc. Fig. 10) due to the repeated impingement of solid particles (sand) or droplets at high velocity.

Fig. 10. Erosion damage in a cage-type choke.

Consequences

Structural damage, vibration, leaks and corrosion (due to the removal of the protective coating).

Management

Erosion is usually accounted for in the field design phase. The design process sizes the equipment such that the velocities are below certain limit value that gives an acceptable erosional rate. These calculations usually consider the velocity of impingement, the angle of impingement, the amount of solid particles and the wear resistance of the material.

There are some standards that give guidelines how to estimate erosive wear for common pipe components (e.g. DNV Recommended Practice RP O501). However, complex geometries usually require in-depth studies (e.g. using computational fluid dynamics, CFD) to estimate erosion prone areas, fluid velocities, angle of impingement, etc. An example is shown in Fig. 11.

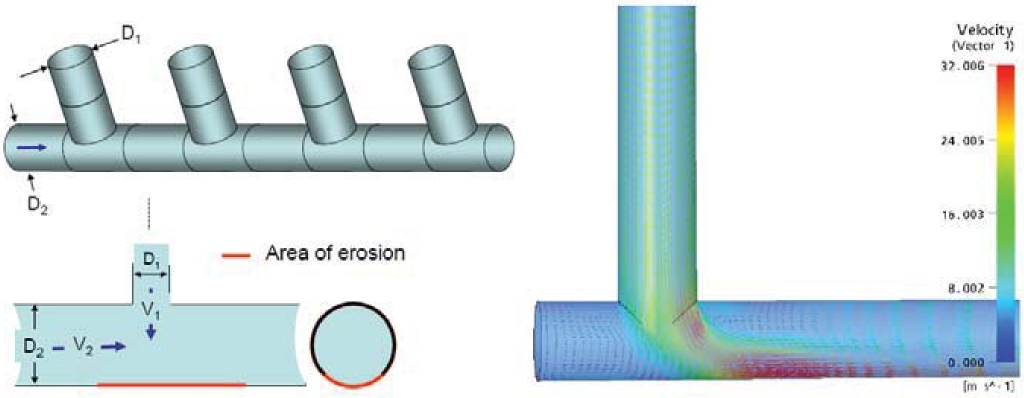
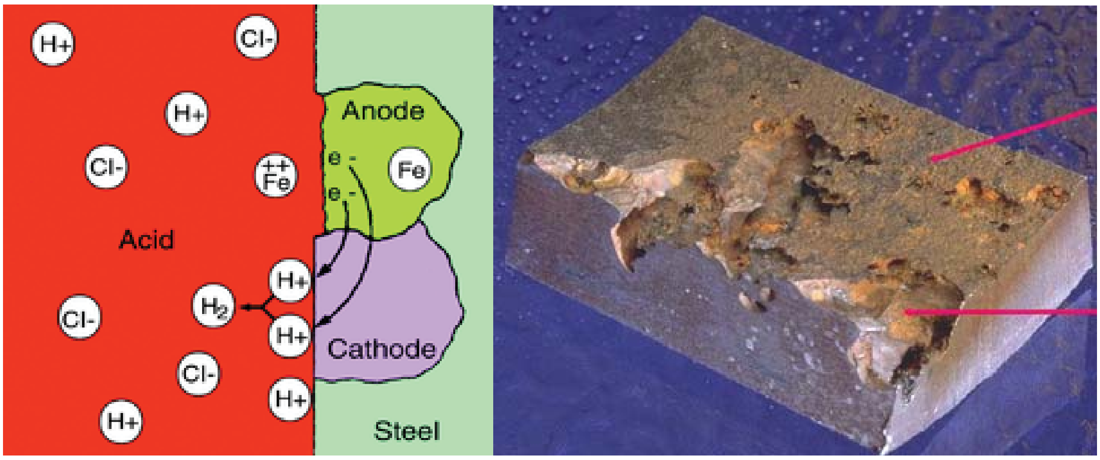


Fig. 11. CFD simulation of erosion in a production header

If erosion is detected in an existing production system then, when possible, components might be reevaluated and replaced with geometries that are less susceptible to erosion. Alternatively, if corrosion is due to excessive sand production from the reservoir, the only alternative is then reduce the well rate to limit sand production.

CORROSION

Corrosion is an electrochemical reaction where steel is converted to rust and occurs when metal is in contact with water. Two locations are established in the metal, a cathode and an anode. In the anode, iron loses electrons and becomes a positively charged ion. This ion further reacts with water and oxygen in the surrounding media to form rust. The cathode receives the electrons of the anode and generates by-products (such as hydrogen H_2) with other ions.



(a) **(b)**

Fig. 12. a) Ilustration or a corrosion reaction b) corrosion on the tubing surface

Corrosion can occur virtually anywhere in the production system where water is in contact with metal (casing, tubing, flowlines, pipelines, tanks, pumps, etc.). In transportation pipes, corrosion usually occurs at the pipe bottom where water is transported, in low pipe sections where water accumulates or at the top of the pipe due to splashing and condensation of water droplets (also known as TLC, Top of line corrosion).

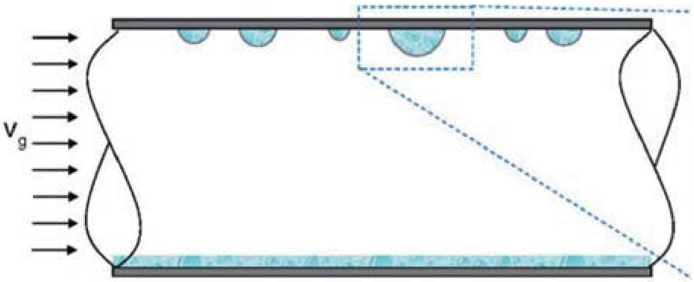


Fig. 13. Wet gas flow in a horizontal flowline depicting top of line condensation

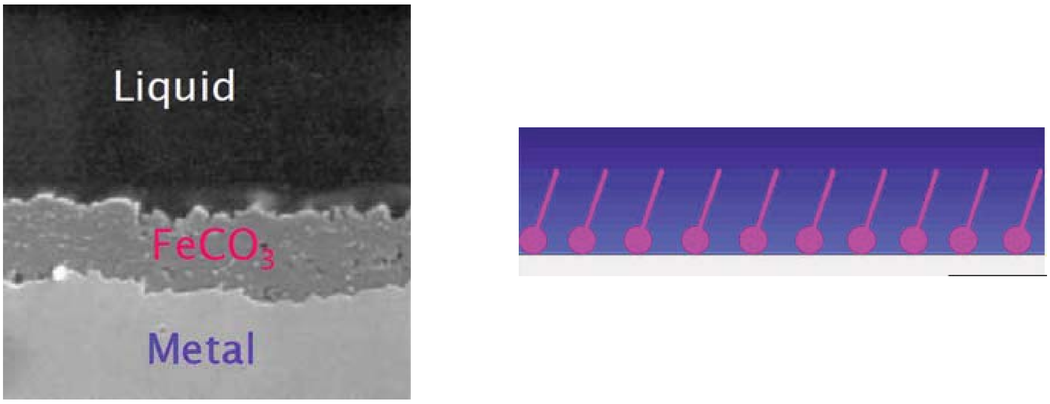
Consequences

Corrosion on an unprotected pipe can cause losses of 1-20 mm of pipe thickness per year, leading ultimately to structural damage and leakages. Rust particles can also travel downstream and cause problems such as plugging other components.

Management

The measures to mitigate corrosion can be divided into two main principles:

- Eliminate the contact between water from steel. This can be done by applying a protective layer on the steel surface, for example with coating (which might be eventually damaged due to sand erosion), creating a layer of protective oxide on the steel (Fig. 14 a) or by using inhibitors (Fig. 14 b).



(a) (b)

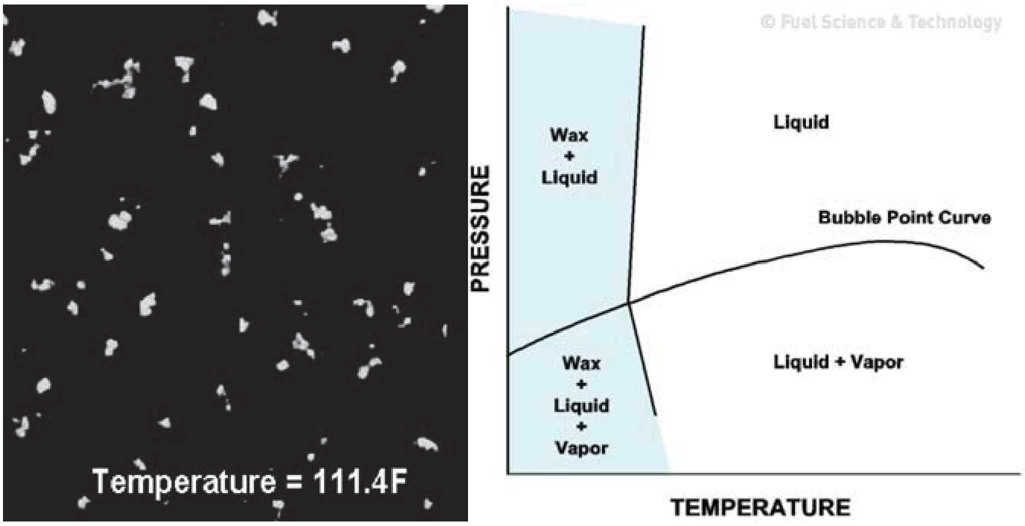
Fig. 14. Protective layer of $FeCO_3$ formed on the metal surface b) inhibitors attached to the metal surface

- Use steel materials with higher resistance to corrosion. For example alloy steels. This is usually feasible for wells, but it becomes too expensive for flowlines and pipelines.

WAX DEPOSITION

Wax deposition occurs when long alkane chains (C18+) precipitate out of solution from the oil, agglomerate and deposit on the pipe walls.

In a waxy crude, when temperature is reduced down to a certain value (for North sea crudes this happens around 30-40 C), some wax crystals will start to precipitate and become visible. The temperature when this occurs is called cloud point or WAT (wax appereance temperature).



(a) (b)

Fig. 15. a) Wax crystals visible in a crude at WAT, b) WATs at different pressures in the phase diagram

The WAT depends on oil composition, type and molar amounts of alkanes, pressure, cooling rate. Wax crystals typically attach to nucleating agents present in the oil (asphaltenes[6], fine sand, clay, water, salt), form wax “clusters” and grow.

If the temperature is reduced further down to the pour point, the oil becomes solid-like and stops flowing.

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[6] Asphaltenes are coal-like solids that also have the tendency to precipitate out of the crude. They are high molecular weight compounds containing poly-aromatic carbon rings with nitrogen, sulphur, oxygen and heavy metals such as vanadium and nickel.

Fig. 16. Crude oil not flowing once the pour point is reached

Wax deposition occurs when ALL the following ingredients are present:

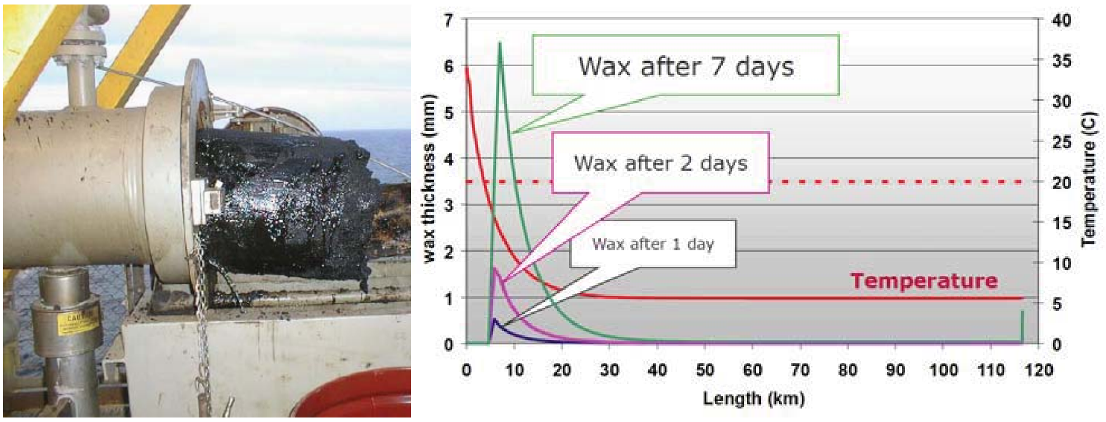
- Wax-prone components in the oil composition (long alkane chains).
- Temperature below WAT.
- Pipe wall colder than the fluid such that there is a temperature profile in the fluid reducing towards the pipe wall (temperature gradient).
- Irregularities on the wall where wax clusters attach.

Wax deposits age with time and become more rigid (thus more difficult to remove).

Consequences

In flowlines and pipelines:

- Increases pressure drop due to the increase in pipe roughness.
- Reduction of cross section area.
- Pipe blockage.



(a) (b)

Fig. 17. a) wax plug retrieved topside (Statfjord B), b) evolution of the wax thickness in a pipeline with time.

- The presence of wax crystals in the fluids changes its rheology (e.g. making it non Newtonian or with a higher effective viscosity).
- During shut-downs, the temperature of the fluid can reach the pour point of the crude, causing it not to flow (gelling).

Management

The first step in developing a wax management strategy is to test the crude oil in the laboratory and measure and quantify all of its properties relevant for deposition.

A common management method for wax is to perform frequent pigging. Pigging consists in sending a device (pig) inside the pipe that scraps the wax deposits and pushes them forward. Pigs are usually sent and received from the processing facilities thus two pipelines must be installed. There are also subsea pig launchers, but this is economic only for systems with very low pigging frequency.

Pigging frequency is usually estimated by performing numerical simulations to compute the profile of deposited wax along the flowline with time. With this, the total amount of wax deposited in the system at any given time is estimated. There is a maximum length and weight of wax that can be pushed through the pipe, given by the maximum allowable pressure that the pipe can tolerate. The required pigging frequency is given by the time at which that wax amount is reached.

Other techniques used are keeping the fluid outside of the wax formation region. This is done by thermal insulation or electrical heating. However, for long flowlines, electrical heating is usually very expensive and insulation alone is not enough to keep temperature high. Thus in most cases insulation or electrical heating are often used to reduce wax deposition rates together with pigging.

Chemical inhibitors that are also often injected. Chemical inhibitors work by reducing the cloud point of the crude or by preventing further agglomeration of wax crystals. As with insulation, in many systems this doesn’t eliminate completely the problem but it helps slowing down the deposition rate. Please note that chemical inhibitors are expensive.

If the seabed temperature is below or equal the pour point of the oil, then it is necessary to inject chemical inhibitors before shutting down the system to avoid gelling.

In recent years pipe coating has been proposed as a technique to avoid wax attaching to pipe walls. However it is not yet field tested.

In systems with wax-prone oils the pressure drop between end points of flowlines should be closely monitored. Any unexplained increase might indicate wax deposition and must be immediately addressed.

OIL-WATER EMULSIONS

Oil-water emulsions are fine and stable dispersions of oil droplets in water or water droplets in oil (Fig. 18). The formation of emulsions depends on a variety of factors such as the dynamics of multiphase flow, the properties of oil and water such as viscosity and interfacial tension, the shear stress (mixing) experienced by the mixture, chemical compounds present in the oil-water interface. In production systems, the mixing is typically generated when commingling production from different sources, due to the violent expansion across the choke, flow through multiphase pumps, etc.

(a) (b)

Fig. 18. a) oil (red) and water (White) originally separated, b) oil and water emulsion after vigorous stirring in a blender

Consequences

In pipe flow, emulsions often exhibit the behavior presented in Fig. 19. For a fixed volumetric rate of the mixture ($q_o + q_w$), if one measures the pressure drop along a pipe segment for several water volume fractions, it will increase with water volume fraction until a maximum is reached and then it will decline abruptly. The water volume fraction that has the highest pressure gradient is called the inversion point. Please note that the increase in pressure drop is significant (more 2.5 times the one for pure oil in the figure).

When increasing the water fraction, at the inversion point the dispersion changes from an oil in water dispersion to a water in oil dispersion.

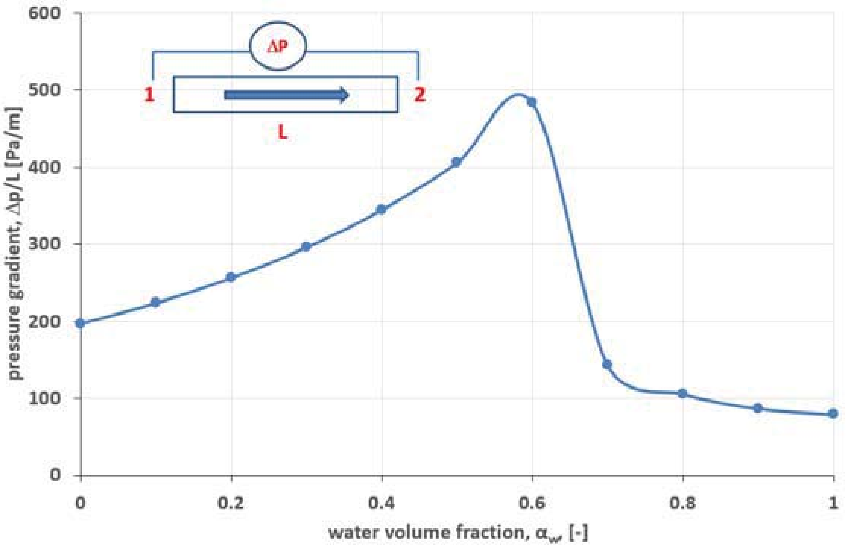


Fig. 19. Measured pressure drop in a horizontal pipe keeping the total flow rate constant and changing water volume fraction, $q_w/(q_w+q_o)$

Using an homogeneous model (single fluid with average properties) one can back-calculate the effective mixture or "emulsion" viscosity that the mixture should have to provide the pressure drop measured (Fig. 20). For the particular case, the emulsion viscosity at the inversion point (570 cp) is 7.1 times the viscosity of the oil (80 cp).

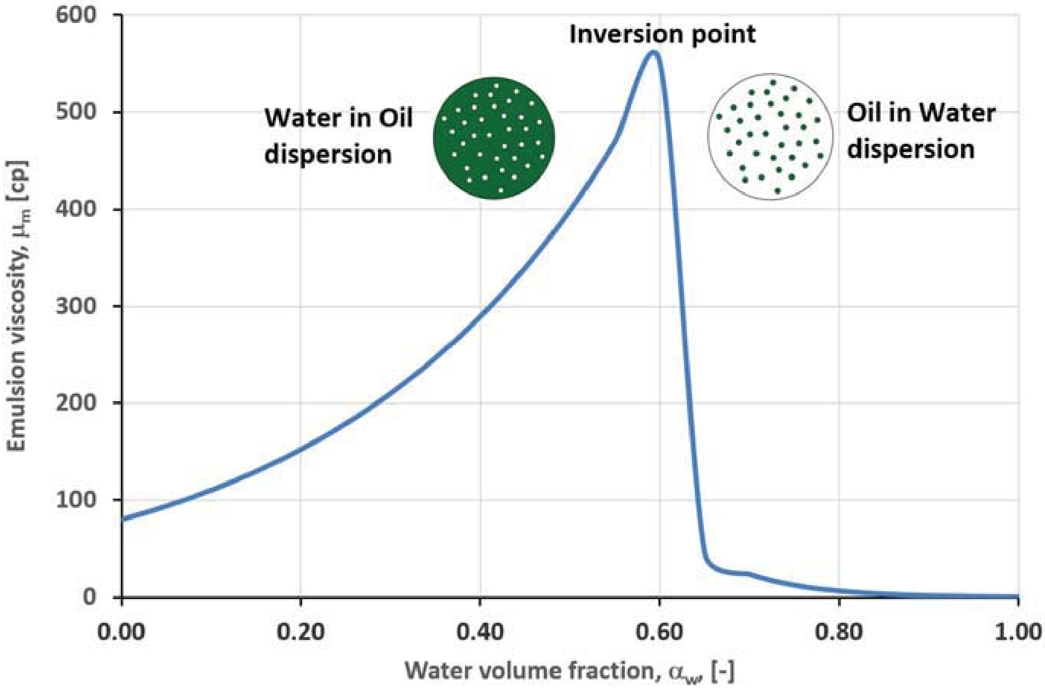


Fig. 20. Mixture viscosity behavior versus water volume fraction exhibited by the oil water mixture

There are many expressions used to represent the behavior shown in Fig. 20 that are later used in emulsion pressure drop models. Most of them require data measured in the lab to tune their coefficients. As an example, the Richarson model is shown below.

For oil continuous

$$\mu_m = \mu_o \cdot e^{n_o \cdot \alpha_w}$$

For water continuous

$$\mu_m = \mu_w \cdot e^{n_w \cdot (1-\alpha_w)}$$

Eq. 1.

Consequences

Emulsions can cause excessive pressure drops in pipe segments and components, which can reduce dramatically production rates, pumping capacity of electric submersible pumps, etc. Moreover, stable emulsions are difficult to separate in processing facilities thus creating bottlenecks and fluid disposal problems.

Management

During the field design phase, the capacity oil and water system to form emulsions can be somewhat studied with laboratory tests (shaking bottle tests). However, these results have sometimes limited applicability partly because the shear magnitudes (mixing) applied in the laboratory conditions are very different from the mixing experienced in the field.

When there is mixing of streams with different water cut, the inversion point must be avoided.

Often, chemical substances such as demulsifiers and light oils (diluent) are injected into the stream to reduce the stability of the emulsion. Light oils reduce the viscosity of the formation oil, thus helping separation. Demulsifiers are chemicals that attach themselves to the interface between oil and water promoting separation.