

Cold Flow Hydrate Technology

Jón Steinar Gudmundsson*

Department of Petroleum Engineering and Applied Geophysics, Norwegian University of Science and Technology,
7491 Trondheim, Norway

Cost-effective exploitation of deepwater oil and gas reservoirs, requires trouble free flow of oil, gas and water mixtures from subsea wellheads to processing facilities, either subsea, topside or beach-based. Cold flow hydrate technology provides an opportunity for flow assurance in deepwater production of oil and gas. Hydrate R&D in the Natural Gas Hydrate laboratory at the Norwegian University of Science and Technology, has demonstrated that hydrate slurries can flow without solids deposition and/or blocking in cold flow pipelines (bare pipe, without insulation and/or heating). A sketch of a cold flow hydrate process is presented; consisting of separation, heat exchange and reactor units.

Introduction

Hydrates form when liquid water and natural gas are in contact at high pressure and low temperature. The pressure and temperature conditions for hydrate formation readily arise in deepwater production of oil and gas. Chemical-based technologies have been developed to cope with hydrate formation in deepwater production. Either, bulk chemicals such as methanol are mixed with the liquid water stream to lower the temperature of hydrate formation. Or, specialised chemicals are added to affect the formation and agglomeration properties of hydrates. In both cases, the chemicals need to be pumped to the wellhead and injected before the oil, gas and water mixture cools down to the temperature of hydrate formation. Other methods exist, for example insulation and heating of the pipeline carrying the fluid mixture.

Cold flow technology concerns cost-effective flow of oil, gas and water mixtures in deepwater production pipelines – from wellhead to processing facility – without the constant (steady-state) use of chemicals to prevent hydrate and/or wax deposition. When an oil, gas and water mixture exiting a warm wellbore enters an un-insulated flowline at seawater temperature, the ensuing cooling results in hydrate formation (and wax deposition). Wellhead temperatures in deepwater production are in the range 40-80 C and seawater temperatures in the range -2 to +4 C. In cold flow technology the hydrate formation takes place under controlled conditions in specialised equipment. The hydrate particles formed should flow readily with the bulk fluid mixture (slurry) and not form wall deposits nor pipeline blockage.

The idea of cold flow technology has been around for many years in the R&D community for natural gas hydrate deposits and paraffin wax deposits. Recent examples of cold flow technology include Amin et al. (2000) and Larsen et al. (2001). Hydrate R&D at NTNU (Norwegian University of Science and Technology) in the 1990's, although with a focus on hydrates for the storage and transport of natural gas, dealt

also with the flow of hydrate particles in liquid water and oils. Experimental work in the NGH (natural gas hydrate) laboratory at NTNU demonstrated that hydrate slurries produced in a continuous stirred tank reactor (CSTR), flowed readily in stainless steel pipes at 70-90 bara and temperatures similar to seawater temperatures expected in deepwater production of oil and gas. No problems were experienced with shut-in and start-up of the laboratory test unit.

NTNU's experimental results on hydrate slurry flow were presented in the open literature by Andersson and Gudmundsson (1999a, 1999b, 1999c and 1999d). Detailed results of the hydrate slurry work were presented in a thesis by Andersson (1999). Other NTNU hydrate theses include Khokhar (1998) and Levik (2000). Results related to the use of hydrates for the storage and transport of natural gas, are presented by Gudmundsson et al. (2002), Levik et al. (2002) and Mork and Gudmundsson (2002).

Deepwater Production

Offshore Mid-Norway, West of Shetlands, Gulf of Mexico, offshore Brazil and West Africa, are all petroleum provinces where deepwater production has started, and is likely to expand considerably the coming decades. With seafloor depths of 1-3 km and temperatures of -2 to 4 C, the technical challenges are many. Flow assurance is a major technical challenge in deepwater production of oil and gas. The 40-80 C hot fluids exiting a wellbore need to be transported to processing facilities located on the seabed, topside or beach. If the temperature of the fluids can be maintained, flow can be assured to the processing facilities. However, the thermal insulation and heating of subsea flowlines/pipelines is considered expensive and will unlikely be used for medium-to-long distances (5 to 50 km). Insulation and heating are considered more suitable for distances of a few kilometres.

Hot wellbore fluids entering a bare flowline (pipe without insulation and heating) on the seafloor, will cool gradually from the 40-80 C to the ambient sea

*E-mail: jsg@ipt.ntnu.no

temperature of -2 to 4 C. The temperature of the flowing oil, gas, water mixture will eventually reach the wax appearance point (WAP), typically in the range $20-40$ C. With further cooling the flowing mixture will reach the hydrate formation temperature, typically in the range $10-20$ C. The pour point of the oil phase will be reached at lower temperatures, typically in the range $0-10$ C. The deposition of paraffin wax takes place when the wall temperature is below the wax appearance point (Bott and Gudmundsson 1977a, 1977b). Different crude oils have different paraffin wax contents, and hence different paraffin wax deposition properties.

Natural gas hydrate forms when liquid water and natural gas are present at high pressure and low temperature. The rate of hydrate formation and the deposition and blocking properties of the hydrate, depend on the conduit (pipeline) transport conditions such as momentum transfer (pressure drop), heat transfer (cooling) and mass transfer (gas-liquid and liquid-solid contact areas). If the fluids produced contain no water (that is, zero watercut, WC), natural gas hydrate will not form. If the fluids produced have no associated gas, natural gas hydrate will also not form. The absence of associated gas means that the in-line pressure is above the bubble point pressure of the crude oil. The absence of liquid water and associated gas means that hydrate will not form in deepwater production operations.

It is unusual to have oil and gas production without some liquid water production. Hydrocarbon production without water production may occur in the early life of a well. With time, however, water breakthrough happens and the water content increases thereafter. The timing of water breakthrough and the rate of increase in water content, vary greatly between wells and fields. In the early life of wells the WC may be a few percent, and in the late life the WC may be above 90 percent.

The volume use of bulk chemicals to lower the hydrate formation temperature is proportional to the WC; as WC increases with time, so must the use of bulk chemicals. The volume use of specialty chemicals is more complicated and need not be proportional to the WC, although it increases with WC. The use of specialty chemicals depends also on the distance from wellhead to processing facilities (the time it takes to flow the distance).

For both bulk chemicals and specialty chemicals, a delivery system needs to be provided; the chemicals need to be delivered to the wellhead. The chemicals can be delivered through a small-diameter pipeline, with flow in the opposite direction to that of the production pipeline. Small volumes of chemicals, specialty chemicals, can also be delivered to the wellhead through fixed tanks, on the seabed or anchored between the seabed and the ocean surface.

Cold flow hydrate technology aims to eliminate the need for bulk and/or specialty chemicals under normal operating conditions; that is, when steady-state operating conditions have been reached. Difficulties will arise in the start-up and shut-in of cold flow technology operations. Start-up and shut-in operations can be managed using bulk/specialty chemicals and/or pipe insulation and/or heating. Whatever system will be selected for start-up/shut-in, it will add cost and complication to deepwater production facilities.

Hydrate Laboratory

The Natural Gas Hydrate (NGH) laboratory at NTNU was built to study production of hydrates and their properties. See Mork and Gudmundsson (2002) for details. The laboratory is designed to operate at pressures up to 120 bar and temperatures in the range $0-20$ °C. It is Ex-II classified and situated in a room with temperature control. The laboratory has a flow loop consisting of four main units: a continuous stirred tank reactor (CSTR), a separator, a shell-and-tube heat exchanger and a centrifugal circulation pump. The main units are connected with 20 mm pipes. The reactor is of relatively standard design (except, twice the height of standard CSTR's) with four baffles and a Rushton impeller with 6 blades. Maximum rotational speed of the impeller is 2500 rpm.

In hydrate formation experiments, the circulation loop is filled with water or a mixture of water and oil. Gas is injected into the flow loop through a sparger at the bottom of the reactor, and is vented out through a gas vent line from the top of the separator. The pressure in the flow loop is kept constant with a back-pressure regulator on the gas vent line. Gas volume injection rate and gas volume vent rate are measured with gas flow meters. From the difference in injection rates and vent rates, the gas consumption rates can be calculated. Pressures and temperatures are measured at various locations around the loop. All instrument output signals are transferred to a PC-based data acquisition system for analysis.

A Coriolis mass flow meter is installed with the intention of measure density and mass flow of hydrate slurry produced in the loop. Experience has shown that it copes well with liquid flows, but poorly with slurry flows, perhaps because of minute gas bubbles. In a test unit downstream the separator, variable equipment such as filters and hydrate sampler can be mounted. A tube viscometer can also be connected to the flexible hoses of the test unit which enables in-line pressure drop measurement of the slurry at the same conditions as in the hydrate flow loop of both oil-continuous and water-continuous hydrate slurries (Andersson and Gudmundsson 1999a, b, c, d). The horizontal pipe section can be connected directly to a gas reservoir for pressure drop measurements with various gases at different flow rates. In a high-pressure flow cell connected at the test unit, hydrate particles can be observed and video recorded.

Slurry Flow Properties

The flow properties of hydrate particles in liquid water and in diesel fuel have been investigated (Andersson 1999; Andersson and Gudmundsson 1999a, b, c, d). Conventional wisdom states that the pressure drop in pipelines is higher in slurry flow than liquid flow (Hanks 1986, Shook and Roco 1991, Wilson et al. 1997). The conventional wisdom holds true for large-particle slurries as found in the minerals and mining industries. The question arises whether it holds for small-particles slurries as produced in the NGH laboratory at NTNU. It has proven difficult to measure the size of the hydrate particles at NTNU, partly because of their small size. The hydrate particle size is thought to be in the size range 5 to 50 μm with 10 to 20 μm as most likely. More R&D work is required in this area.

The viscosity of liquids is traditionally measured in equipment where the shear rates correspond to laminar flow conditions. In commercial pipeline operations, however, the flow conditions are predominantly turbulent.

In slurry pipeline operations, the pressure drop at turbulent flow conditions is of major interest. A method widely used in slurry pipeline studies is to measure the hydraulic gradient and plot against the Reynolds number. The hydraulic gradient (expressed by symbol i), gives the pressure head of water per pipeline length expressed as $i = (\Delta p)/(L\rho g)$. The Reynolds number is expressed by $Re = \rho u d/\mu$. The symbols have their usual meaning. Hydraulic gradient plot can illustrate both laminar flow and turbulent flow conditions.

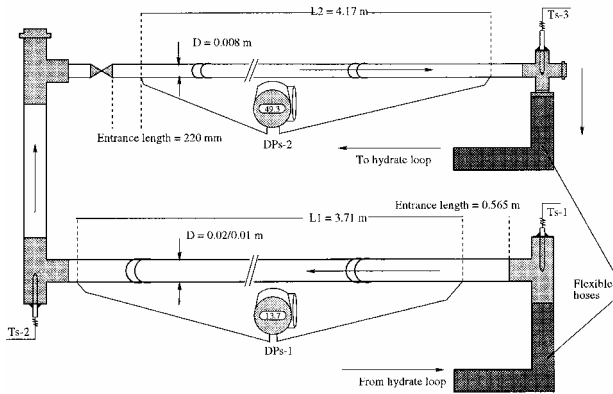


Figure 1 – Tube viscometer in hydrate laboratory.

The NGH laboratory tube viscometer was used to study the slurry flow behaviour of hydrate particles in liquid water and diesel fuel oil. The tube viscometer is illustrated in Figure 1. It has two 5 m long tubes, 8 and 20 mm in diameter, where the pressure drop is measured over a distance of 4.17 m and 3.71 m after entrance lengths of 0.22 m and 0.565 m, respectively. Hydrate slurries were produced in the NGH laboratory test unit at NTNU (see Mork and Gudmundsson (2002) for description of general procedures). Slurries of different solids concentration were produced. When the required solids concentration was achieved, the gas-feed to the CSTR was shut-in and the slurry circulated for a while in the test unit. The nature of the slurry was observed through the window of a high-pressure flow cell, to ensure that all gas bubbles had been removed (in separator of test unit). The liquids used were water from the tap (de-aerated in test unit) and commercial grade diesel fuel.

The tube viscometer was calibrated using liquid water. The test results are shown in Figure 2, illustrating the hydraulic gradient plotted against the Reynolds number. The laminar flow regime extends to a Reynolds number of about 2600. The system behaviour is described by the Hagen-Poiseuille equation. At higher Reynolds number, the liquid water data follow another curve, the curve for the turbulent flow regime. The system behaviour is described by the Darcy-Weisbach equation (see also Sletfjerding and Gudmundsson 2001). In addition to the data points in Figure 2, two solids lines are shown, representing the two above equations (theoretical lines). The friction factor in the turbulent flow regime was estimated from the Blasius equation (other more detailed friction factor equations could also have been used).

The tube viscometer was used to test hydrate in water slurries. Typical test results are shown in Figure 3, illustrating the hydraulic gradient against Reynolds

number for a 32 % slurry. The percentage is approximate volume percentage of solid hydrate in liquid water (Andersson 1999). Similar results have been presented for 2, 12, 18 and 22 % hydrate-in-water slurries (Andersson and Gudmundsson 1999a, b, c, d). In the laminar flow regime, the hydraulic gradient is well above the theoretical line for water. That is, the effective slurry viscosities are greater than that of liquid water, as would be expected from conventional wisdom.

In the turbulent flow regime in Figure 3, the effective slurry viscosities are exactly the same as the theoretical line for water. Surprisingly, the experimental results were not as would be expected from conventional wisdom. The implication of the results presented in Figure 3, is that hydrate-in-water slurries transported in pipelines, will be subjected to the same/similar pressure drop as liquid water. That is, the pressure drop in pipelines carrying hydrate-in-water slurries will not be higher than the pressure drop in pipelines carrying liquid water. It is postulated here that the hydrate particles were small, perhaps smaller in size than the thickness of the laminar sub-layer, and moved away from the pipe wall due to the shear gradient (perpendicular to the flow direction).

The tube viscometer was used to test hydrate in diesel fuel slurry. Typical results are shown in Figure 4, illustrating the hydraulic gradient for a 12.7 % slurry. The hydrate-in-oil results were found to exhibit similar behaviour to the hydrate-in-water results. In the laminar flow regime the effective viscosity was greater than the liquid alone, and in the turbulent flow regime the effective viscosity of the slurry and liquid were the same/similar.

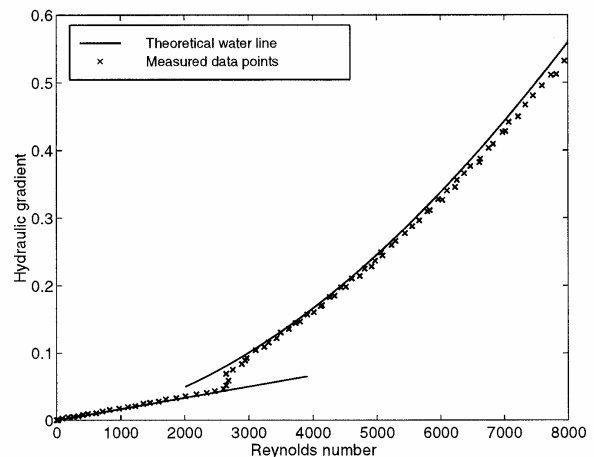


Figure 2 – Hydraulic gradient for liquid water plotted against Reynolds number.

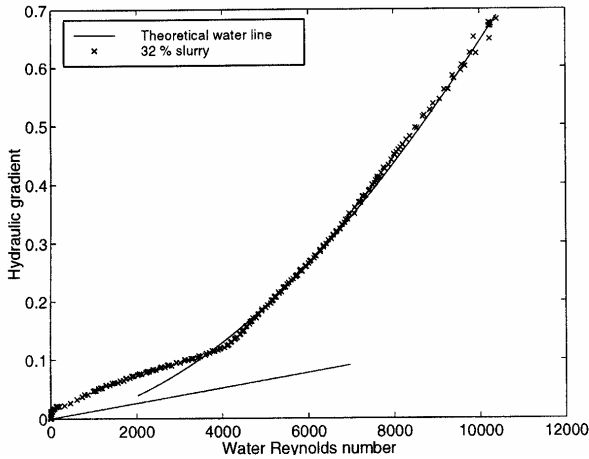


Figure 3 – Hydraulic gradient for 32 % hydrate-in-water slurry plotted against Reynolds number.

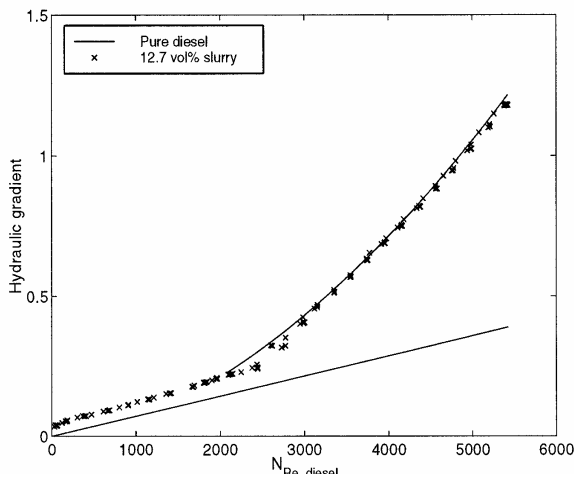


Figure 4 – Hydraulic gradient for 12.7 % hydrate-in-oil (diesel fuel) slurry plotted against Reynolds number.

Cold Flow Process

The hydrate slurry experimental results obtained in the NGH laboratory at NTNU, may have important implications for deepwater production of oil and gas. The results suggest that hydrate technology can be used to achieve cold flow from wellhead to processing facilities (subsea, topside, beach). Basically, the liquid water produced with the oil and gas would be converted to hydrate particles. The hydrate particles would flow with oil phase as slurry in three-phase flow (gas, liquid, solid). Based on experience gained in the NGH laboratory at NTNU, cold flow hydrate technology processes can be proposed. The flow diagram of one such process is shown in Figure 5; the flow enters from a wellbore (WELL) and leaves through a cold flow pipeline (CFP).

The cold flow hydrate technology process in Figure 5 has several main process units: a wellhead unit WHU, a separator unit SU, a heat exchanger unit HXU and a reactor unit RU. The well in Figure 5 produces an oil, gas and water mixture into the WHU. The WHU

represents the valves and whatever auxiliary equipment

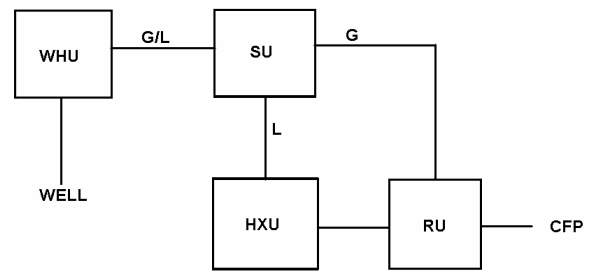


Figure 5 – Block diagram of cold flow hydrate technology process, illustrating wellhead unit WHU, separator unit SU, heat-exchanger unit HXU and reactor unit RU, feeding into a cold flow pipeline CFP.

required for subsea wellheads. A gas-liquid mixture is shown flowing from the WHU to the SU. The gas-liquid mixture is separated, the liquid phase flowing to the HXU and the gas phase to the RU. The cooled liquid phase and the gas phase are brought together in the RU, where hydrate formation occurs. The process in Figure 5 illustrates one set of units. Depending on the watercut WC, the gas/oil ratio GOR and other fluid properties, more than one set of SU+HXU+RU may be required.

The results of Mork and Gudmundsson (2002) can be used to design the RU in the cold flow hydrate process. Other reactor designs can also be used. Established design methods can be used to design the SU (gas-liquid separation). The design of the HXU, however, may involve technical challenges. Natural cooling can in principle be used, such that the 40-80 C fluid mixture from the WHU be cooled close to the ambient sea temperature of -2 to 4 C. But natural cooling requires large heat transfer surfaces, especially to achieve cooling approaching the ambient sea temperature. An alternative would be to use active cooling, to achieve lower temperatures in smaller equipment. R&D work is needed to consider what kind of active cooling would be suitable for deepwater production conditions.

Hydrate crystals are made up of water molecules and encaged gas molecules. The crystals form particles through agglomeration and similar mechanisms. The water-nature of hydrate particles makes them hydrophilic (they like water). Steels and stainless steels are usually also hydrophilic, such that liquid water and hydrate particles tend to adhere to metal surfaces. The surface properties of metals can be changed by the application of chemicals and coatings. For example, corrosion inhibitors applied in pipelines tend to make the surface hydrophobic (opposite to liking water). And epoxy coating of pipelines is used to change the surface properties, in addition to reducing the roughness (Sletfjerding and Gudmundsson 2001). In cold flow hydrate technology, it would be advantageous to use hydrophobic surfaces, both in the process units and the pipeline.

Natural surfactants in crude oils, additives and specialty chemicals, have the potential to alter the behaviour of hydrate and wax particles in three-phase

flow (cold flow pipeline). The same and similar materials are likely affect the separation properties in the SU and the hydrate formation properties in the RU (see Figure 5). Leporcher et al. (1998) and Bergflødt (2001) have reported how surface active materials affect the flow properties of oil, gas and water mixtures in deepwater production.

Concluding Remarks

Cold flow technology holds the promise to reduce the cost of deepwater production facilities, thus extending the petroleum resource base in the major offshore basins of the world. The technology concerns cost effective and trouble free flow of oil and gas from deepwater wellheads to processing facilities located sub-sea, topside or beach-side. Cold flow technology is environmentally friendly because of envisaged reduction in the use of bulk and specialty chemicals.

Hydrate-in-water and hydrate-in-oil slurry studies in the NGH laboratory at NTNU have demonstrated that the pressure drop will not be greater than that expected in the flow of the carrying liquid alone (water only or oil only) flows. Furthermore, the NTNU results also show that hydrate slurries are not likely to form wall deposits and solid plugs, resulting in the blockage of cold flow pipelines. Cold flow hydrate technology aims for flow assurance in deepwater production.

Cold flow hydrate technology is relatively new and R&D efforts are needed before commercial applications can be planned. R&D results from a wide range of natural gas hydrate studies world-wide, for the purposes of flow assurance, subsurface hydrate resources and storage/transport of natural gas, will benefit endeavours to take cold flow technology in early use. Robust and reliable technology for rapid cooling needs to be investigated.

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