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Prediction of Gas Hydrates Formation in Flow lines

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Abstract

Hydrates formation in oil and gas pipelines may lead to severe operating problems and production losses. Once the flow conditions (T and P) are within a stable hydrates region, hydrates formation is likely. Therefore, prediction of hydrates formation region of temperature and pressure is highly important. Analysis of pipelines flow conditions is highly needed to avoid hydrates formation and plugging of flow lines and piping system under both steady and transient flow conditions. Transient flow may include start-up, shut down, increase (ramp up) and decrease (ramp down) of flow rates. Flow assurance results are the basis of the conceptual design of production and transportation facilities in oil fields. Prediction and knowledge of hydrates formation region may determine the needed equipment, production strategies, injection of hydrates inhibitors, heating and or insulation of piping system . . . etc. Modern computer software (such as HYSIS and OLGA) is very helpful in developing conceptual design of surface facilities in oil fields. This paper demonstrates the utilization of modern computer software to predict when and where hydrates will form in flow lines. Two cases are considered; an offshore, subsea tie back line and a subsea flow line.

Keywords: Gas hydrates; hydrate formation; pipeline hydrates.

1. Introduction

The gas hydrates formation is well covered in text books. From practical point view, prediction of when and where hydrates will form is highly important for the operation of gas facilities. Several correlations have been utilized to predict the region of temperature and pressure where hydrates formation is likely. Only recently the application of transient flow models enables the prediction of when and where hydrates will form.

In steady state operations, Hammerschmidt's equation has long been used for prediction of the amount of inhibitors (methanol or glycols) needed to reduce the hydrates formation temperature at the specified operating pressure1. However, operation of any gas processing and transportation facilities are subject for transient operations. Such operations include flow ramp up, ramp down, shut in and start up. Prediction of temperature profile and phase distribution along the lines is highly important. For safe and economic operations, fluid temperature and pressure should always be outside the hydrate formation region.

During steady state flow, fluid temperature drops due to cooling effects. Measures such as heating or injection of inhibitors are taken to ensure fluid temperature is above the hydrate formation temperature of the fluid. However, these measures may not satisfy the requirements for other flow conditions encountered in transient operations such as increased, decreased flow, shut in and start- up of cold pipelines.

The use of modern computer software enable engineers to carry out calculations to predict flow performance during all operation stages starting

from startup of cold flow lines, steady flow and any emergency or planned shutdown. This paper presents two case studies; an offshore flow line and a subsea trunk line. The use of hydrates kinetic model in OLGA permits the prediction of when and where hydrates will take place.

2. Gas Hydrates

Gas hydrates are an ice like material that form at temperature will above water freezing temperature. Some hydrocarbon molecules (CH_4, C_2H_6, C_3H_8, i-C_4H_8) and non- hydrocarbon molecules (H_2S and CO_2) are capable of forming hydrates in presence of free water. Formation of hydrates may lead to severe problem such flow reduction and damage to equipment. Hydrates formation region is determined by calculating the pressure and temperature at which hydrates are stable:

$$K_i = \frac{Y_i}{X_i} \tag{2.1}$$

Where Yi and Xi are the mole fractions of component i in both the vapor and solid phases. The procedure of calculations of hydrates formation is well explained in text books1.

2.1. Kinetics Model

The details for gas – oil dominated - water, gas dominated- water and Gas – condensate –water systems are presented in reference 2. For the oil dominated – water system, it is proposed that hydrate plug formed through four main steps:

- Water entrainment; where water droplets are dispersed in continuous oil phase as water in oil emulsion.
- Hydrate growth; hydrate shells form at the interface between water droplets and oil phase.
- Agglomeration; hydrate – encrusted water droplets may agglomerate increasing into larger hydrate masses.
- Plugging; the agglomeration of hydrate particles leads to an increase of slurry viscosity which eventually form a plug.

L.E. Zerba et al3 developed a transient hydrate kinetic model. The model describes the kinetics of hydrate plug formation in oil dominated system.

$$dMgas/dt = -uK1Exp.$$

$$\{K2/Tsystem\}\left(Asystem/Tsub\right) \tag{2.2}$$

Where K1 and K2 are constant derived from experimental data; from a plot of amount of gas consumed vs. T sub. A is the surface area between oil and water phases and T sub is the sub cooling temperature difference: T sub = T − T hyd.

2.2. The Colorado School of Mines Hydrate Kinetics model

CSMHyK is a module for the OLGA transient, multiphase, flow simulator; CSMHyK has been under development since 2003. This model simulates hydrate plug formation in flowlines using the transient, multiphase flow simulator, OLGA. The model predicts the rate of hydrate formation using a first-order rate expression. Details of the module are presented in reference 4. Nucleation is assumed to occur instantaneously at a sub cooling of 3.6° C or 6.5° F.

2.3. Erosion velocity

In multi-phase flow, erosion may become severe due to impingement of liquid droplets on piping walls of elbows, bends, valves . . . etc. The erosion velocity should be considered especially at high gas production rates. Mixture velocity should always be less than erosion velocity. API RP 14E defines the erosion velocity as:

$$V_{erosion} = C/\left(\rho_{mixture}\right)^{0.5} \tag{2.3}$$

Where ρ mixture is the flowing fluid density Lb/Ft^3 and C is a constant depends on pipe material, amount of solids and operating conditions. API RP 14E recommends a value of C = 100 − 130.

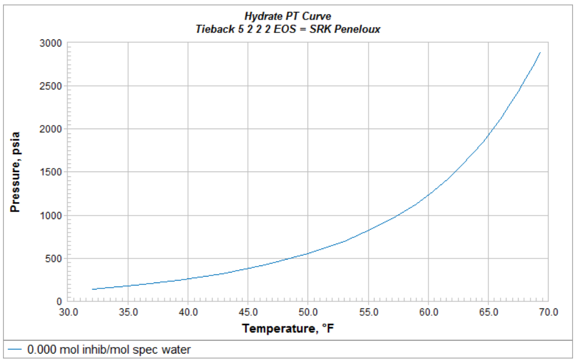

Figure 3.1: Hydrates Formation Curve for reservoir fluid.

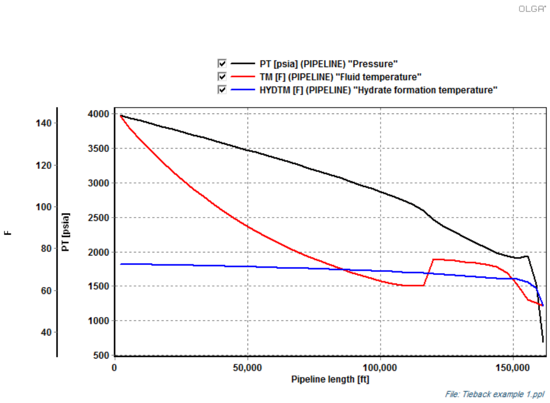

Figure 3.2: Temperature and Pressure Profile.

3. Case Studies

3.1. Tie Back Example

This example is presented to validate our simulation results to published and field data as presented in reference 4. The flow line connects a subsea well to a platform. The flowline is 8 inch, 30 miles long with 5000 Ft riser. The wellhead is assumed to be at 150 ^{o}F and 4000 psig. The oil API gravity = 38, water cut = 30% and the GOR = 1000 scf/bbl. The sea bed temperature = 39.2 F. The separator pressure = 265 psia.

The software Aspen HYSIS was utilized to simulate the reservoir fluid. Due to lake of data, a typical reservoir fluid composition was adjusted to give oil, gas and water flow rates and properties that match the given data. PVT Sim was also utilized to generate feed property table needed by OLGA and the hydrate formation curve, Figure (3-1), for the reservoir fluid. Hydrates formation is likely at any pressure and temperature located in the region on the left side of the curve. High pressure and lower temperature encourage hydrates formation. On the other hand, lower pressure and higher temperature discourage hydrates formation. Figure (3-2) presents temperature and pressure profile for the selected tieback example. Figure (3-2) shows that fluid temperature drops to the hydrates formation temperature at about 22 km. This result matches that given in reference 4. Due to the heat of the exothermic kinetics hydrat formation reaction, flowing fluid temperature slightly rises above hydrates temperature then drops again.

3.2. Offshore Subsea Flowline

A subsea well is connected to a platform through 4 inch, 11 km flowline. The water depth is 160 – 170 m and sea bed temperature is 13 C. The wellhead fluid is subject to sever cooling and arrives at 45 F. The well has experienced flow difficulties for several years as wellhead fluid flows through the flowline, normally for 2 – 3 weeks, ended with a sharp increase in pressure drop. Operators are forced to shut –in the well for few days then the cycle is repeated.

Analysis of the situation indicates that pressure drop increase is likely due to:

- Wax precipitation which may reduce the effective pipe diameter resulting in increased pressure drop. However, wax precipitation may take several weeks and pressure drop may increase slowly not suddenly. It is concluded that wax precipitation is not the main cause for the sharp pressure drop increase.
- Hydrates formation is the most likely cause of the sudden pressure drop increase. Temperature profile (arrival temperature) strongly depends on flow rate. The lower the flow rate, the more heat loss and the lower arrival temperature, which encourages hydrates formation resulting in increased pressure drop.

4. Results and Discussion

The hydrate formation curve for the wellhead fluid is similar to Figure (3-1). As pressure increases, hydrates formation temperature increases. This

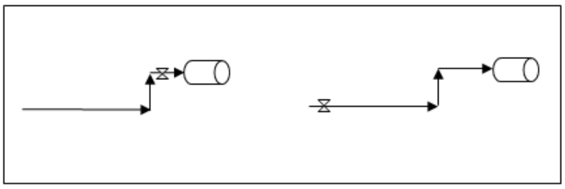

Figure 4.1: Location of Choke Valve.

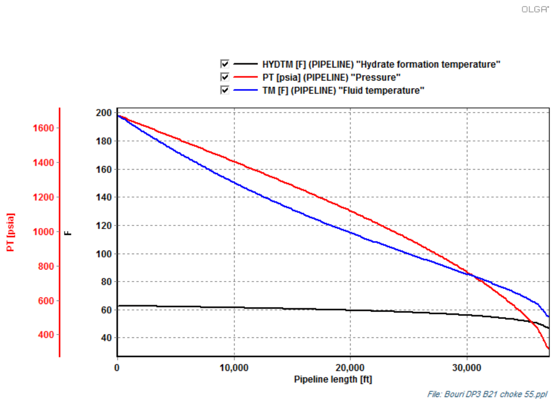

Figure 4.2: Temperature and Pressure profile.

means that the flow line should be operated at lower pressure as possible. The subject flow line was simulated using OLGA. The pipe parameters (insulation material properties and thickness, sea bed temperature) are adjusted to match the fluid arrival conditions (45 F and 300 psia). Two operating scenarios are available, Figure (4-1):

1. Well chocking valve is downstream the flow line.

In this case, the flowline upstream pressure is the as the wellhead pressure. A valve installed downstream the flowline is partially opened so that downstream pressure matches separator pressure. In this case, the flowline is operated at higher pressure and it is more likely subject to hydrate formation.
Figure (4-2) presents the temperature and pressure profiles at a flow rate of 1200 bblpd and water cut of 38 – 40% and GOR = 2600. The obtained results show that the fluid arrival temperature is below the hydrate formation temperature. This indicates that hydrates formation is likely at the end of the flow line.
2. Well chocking valve is upstream the flow line. In this case, the choke valve is installed at the inlet of the flow line. The choke valve opening is

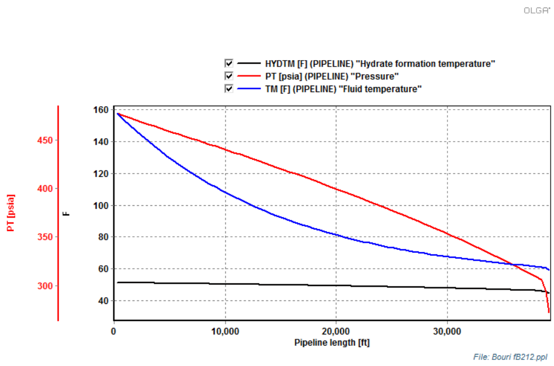

Figure 4.3: Temperature and Pressure profile.

adjusted so that the arrival pressure is the same as the separator pressure. In this case, the flowline is operated at lower pressure. Figure (4-3) presents the temperature and pressure profile at a flow rate of 1200 bblpd and water cut of 38 – 40% and GOR = 2600. The obtained results show that arrival temperature is above the hydrate formation temperature.

4.1. Effect of Flow Rate

Flow rate has a significant effect on the operation of the flowline. At lower flow rate, the flowline is subject to severe cooling due to lower energy input. Figure (4-4) indicates arrival fluid temperature is well below hydrates temperature at a flow rate of 500 bblpd. On the other, at high flow rate, erosion velocity may be the controlling parameter due to high gas velocity. Figure (4-5) shows that fluid velocity/ erosion velocity (EVR) is slightly higher than recommended value of 0.8 at a production rate of 1500 bblpd.

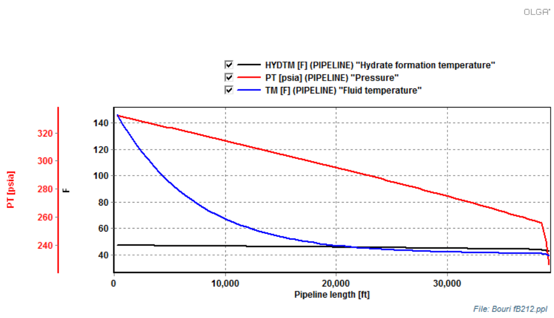

Figure 4.4: Temperature and Pressure profile at rate of 500 bblpd.

4.2. Effect of Shut down

The flowline is subject for frequent planned and unplanned shutdowns. An action is needed after a given period of time (called the cooling time or the no touch time) to prevent pipe plugging. Determination of the cooling time is highly needed. For this particular flowline, the cooling time is determined by allowing the flow for 5 hours, shutdown for 10 hours followed by flow for 5 hours. Figures (4-6) and (4-7) present the temperature and pressure profile for both upstream and downstream choking operations. In both cases, only few hours are allowed before hydrates formation in flowline is possible.

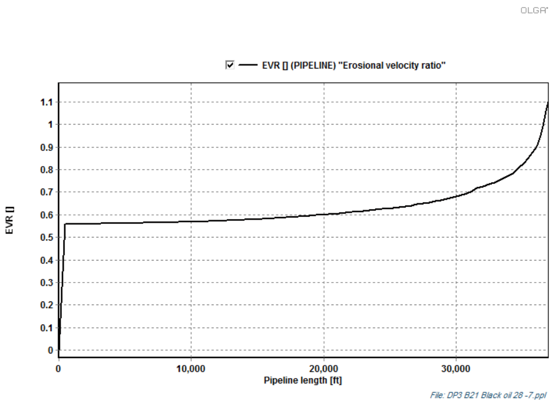

Figure 4.5: Fluid velocity/ erosion velocity ratio at a flow rate of 1500 bblpd.

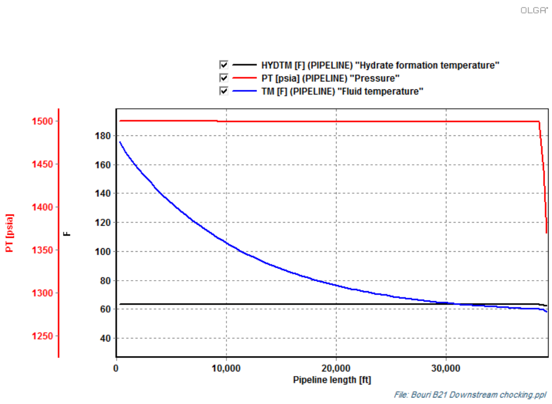

Figure 4.6: Fluid velocity/ erosion velocity ratio at a flow rate of 1500 bblpd.

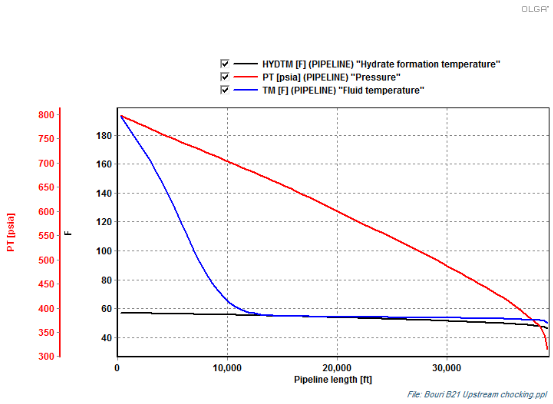

Figure 4.7: Temperature and Pressure profile for downstream choking.

5. Conclusions

Modern, transient computer software can be highly useful for oil companies in design and operation stages of process and production facilities. Knowledge of when and where hydrates form would be the most important for operation of oil and gas subsea flowlines. Operating flowlines at lower pressure (upstream choking), allows hydrate formation at lower temperature as compared to higher pressure (choking downstream) operations. Prediction when hydrates will form would be highly important for management of any, planned or emergency, shutdowns.

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