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Experimental Investigation of Multiphase Flow Effects on the Hydrate Formation Process in an Offshore Pipeline

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Abstract

Multiphase flow is a multi-component flow which occurs in many industrial processes including those involved in the pharmaceutical, food, and processing and petroleum industries. Oil and gas exploration, production and transportation in arctic and offshore conditions are technically very challenging. In addition to the technical challenges involved in arctic operations, there are several environmental challenges posed by offshore operations. One of the operational challenges of hydrocarbon transmission through flow lines in offshore and arctic environments is the formation of hydrates. This imposes a severe flow assurance challenge in offshore operations. Hydrates can form during untreated hydro carbon flow through a pipeline with high pressure in cold weather. These untreated hydrocarbons can be characterized by their multiphase nature and therefore require flow assurance analysis and evaluation during each design stage of offshore project. The main goal of this study is to conduct experiments to understand how multiphase flow affects the formation of hydrates in flow lines. From the preliminary experimental results in the Multiphase Hydrate Flow loop at Memorial University of Newfoundland, we have observed that two-phase gas-liquid flow produces higher pressure in the flow lines compared to single- phase flow. Moreover, due to turbulence in the bends of the flow lines, there is an approximately 1 degree Celsius local temperature increase in bends. In the future work related to this study, a parametric study will be presented to attempt to understand how multiphase hydrodynamic and pipe length scale (diameter) will affect the hydrate induction time. This study will also help to minimize flow assurance challenges in offshore flow lines and provide improved designconditions.

Keywords: Multiphase flow, hydrate formation, induction time, pressure and temperature

1. Introduction

In the present work, flow phenomena of multiphase flows in a pipeline are studied. In the offshore oil and gas industry, one of the biggest challenges is to overcome flow assurance issues. This research investigates the fluid mechanics in a horizontal pilot scale experimental setup. Moreover, the fluid dynamics for different pipe angles is analyzed by studying the pressure drop and friction factor of different two-phase flows in relation to the liquid flow rate. The friction factor is a very important parameter for the extraction of oil from wells. The different frictional effects are the most significant input in the pressure drop between the oil reservoir in the ground and the oil platform. The total pressure drop is composed of the hydraulic pressure drop, the friction pressure drop and pressure drop through the fittings, instruments, and elbows in the pipe system. These pressure effects have an important influence on the output of the oil well and must be determined

as accurately as possible to ensure economic feasibility of the oil production. If the pressure drop of a multiphase flow through a pipe is accurately known; the oil extraction can be optimized. The analysis of the different pressure phenomena in oil reservoirs and well- bores is important to forecast the effect of the pressure drop along the length of the pipeline. In particular, a large pressure drop has to be overcome if the permeability of the formation is poor. Therefore, the pressure drop in the well should be limited. In order to do so, the pressure drop and its causes have to be known as accurately as possible [1] [2]. Through this study of the pressure drop, oil industry is supported in avoiding problems such as those described above. For a flow with a high Reynolds number shows a turbulent flow pattern. For turbulent flow, the friction factor depends on the wall roughness. At low flow rates a laminar sub layer exists on the pipe wall suppressing the influence of the pipe wall on the friction. At high flow rates this sub layer exists as well, but it is thin compared to laminar flow and the pipe roughness is significant [3]. This study helps to understand how the friction factor changes at different flow regimes in horizontal pipe sections, thereby optimizing the flow behavior in pipelines.
The objectives of this project are:

- Develop an experimental setup for studying multiphase flow and hydrates investigation
- Preparation the experimental set-up for future-experiments
- Investigate of flow properties such pressure and temperature and their effects on hydrate formation with basic experiments for multi phaseflow.
- Comparison between using CO_2 and Air as a secondphase in pipeline system.

2. Literature Review on Health & Safety in off Shore Flow Assurance

2.1. Introduction

When considering the production of oil and gas (hydrocarbon fluids) from offshore gas systems, flow assurance is an important issue [4]. In particular,Flow assurance is a major challenge in offshore and deep-water operations in the oil and gas industry. In a survey of 110 oil companies, the flow assurance was listed as the major technical problem in offshore energy development [5]. Understanding the arise of hydrate blockages in pipelines is crucial for the prevention of this important safety issue. Flow assurance covers the following topics in multiphase hydrocarbon production systems:

- Hydrates: The formation of ice particles in low temperature, high pressureflow.
- Waxes/asphaltenes: The deposition of solids in the pipeline,thereby reducing the flow capacity through thepipeline.
- Slugging: The phenomenon caused by instabilities of the gas and liquid interface and liquid sweep-out by gas inertialeffects.
- Erosion: Wear of the pipe work and pipeline wall due to solid particles such as sand or liquidimpingement.
- Corrosion: Wear of the pipeline resulting in the reduction of wall thickness due to the chemical composition of the producedfluids.
- Emulsion: Oil and water mixture at approximately 40-60% water cut that causes excessive pressuredrop.
- Scaling: Solid build-up, especially on the wellbore tubing, due to the chemical composition of produced water[5].

Production facilities, especially offshore wells and offshore transmission lines, may be operated under conditions where hydrate formation is favorable. Gas hydrate formation occurs when neutral gas molecules are surrounded by water molecules. These cages are known as “clathrates” [6]. Gas hydrates are similar in appearance to ice. Both materials have crystalline structures with similar characteristics. The important difference between ice and natural gas hydrates is the guest molecule that is an integral part of its structure [7] [8] [9] [10]. Examples of typical hydrate forming gases include nitrogen, carbon dioxide (CO_2), hydrogen sulfide (H_2S) and light hydrocarbons (such as methane up to heptanes) [6]. Depending on the gas composition and the pressure, gas hydrates can form at temperatures of up to 30 °C (86 °F) where gas co-exists with water [11] [12].

2.2. Formation of Hydrates

Inclusion compounds or "clathrates" are identified as natural gas hydrates. In a typical hydrate there is a network of cages of water molecules which can adherence small paraffin molecules like methane, ethane or propane. There are three common hydrate structures, known as structures I, II and H (Figure 2.1). In the oil and gas production and processing structure I and II are the hydrate structures typically found. The following four structures rule of thumb is applied in safety and flow assurance [13]:

- The fit of the guest molecule within the host water cage determines the crystalstructure.
- The guest molecules are concentrated in the hydrate by a factor as high as180.
- The guest to cage size ratio controls the formation pressure and temperature.
- Because hydrates are 85 mole% water and 15 mole% gas, gas-water interfacial formation dominates[14].

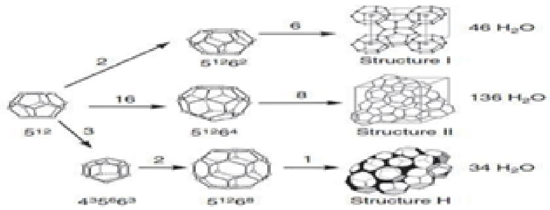

Figure 2.1: The three repeating hydrate unit crystals and their constitutive cages

Figure 2.2 shows how hydrates are formed in a pipe system. At the beginning, the three phases, oil, gas and water, are in the oil well. Due to the cold temperature, high pressure and other influences, the hydrate shells grow and agglomerate to a hydrate plug.

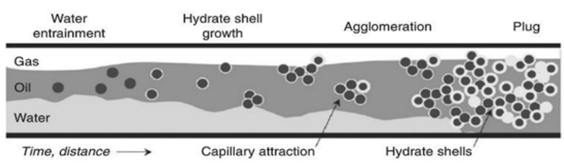

Figure 2.2: Conceptual picture of hydrate formation in an oil-dominated system

Figure 2.3 shows the places where hydrates occur and cause problems during offshore deep-water oil production. The hydrate can block the X-mas tree on the oil well. More- over, they can form in the transport pipeline or the riser to the oil platform [14].

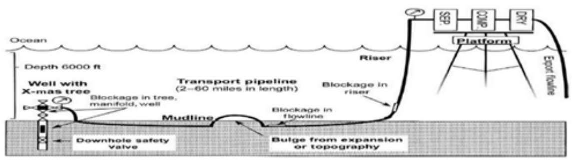

Figure 2.3: Places where hydrate plug formation in offshore pipelines can occur

2.3. Safety and Flow Assuranceissues

Flow assurance issues are numerous in deep-water applications because of the high hydrostatic pressure and the low temperature in the depth. Plug acceleration and expansion becomes an increasing problem as water depthIncreases [5]. Figure 2.4 shows how the pipe is damage by hydrate plugs in two different ways. High velocity hydrate plugs can erupt from the pipeline at a bend and the pipeline can be ruptured by an increase in pressure caused by a hydrate plug's high momentum impact with e.g. a closedvalve.

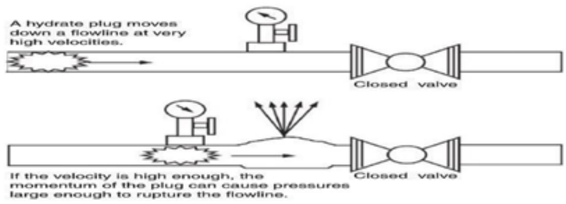

Figure 2.4: Pipeline rupture due to high-momentum hydrate plugs

A hydrate plug's molecules are much closer together than they would be at ambient conditions. Hydrates concentrate the gas volume by as much as a factor of 180, relative to the gas volume at 273 K and 1 atmosphere [14]. Figure 2.5 shows a pipe with two hydrate plugs. Two plugs of hydrates can generate an unknown high pressure zone between each other. This effect results in the damaging of the pipeline.

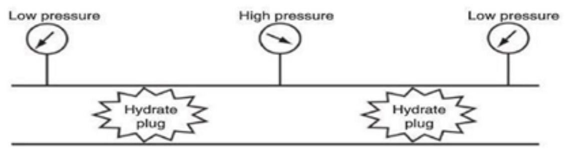

Figure 2.5: Safety hazard caused by multiple hydrates plugs that trap intermediate pressure

3. Development of Multiphase Flow Experimental Setup

3.1. Description of The Experimental Setup

The flow loop is a 67.5 feet pipe (test section) open cycle system. The liquid can be pumped from the tank through 0.75 inch PVC pipe. Transparent PVC pipes are used to facilitate visualization. Currently, two-phase flow can be created by mixing the gas flow from the gas cylinder or air through airline and the liquid from the liquid line. Instrumentation includes eight pressure and temperature sensors, and flow meters for the gas and liquid pipes to measure the individual gas and liquid flow rate. The air injection pipe is also provided to run the pump. Manual control valves are installed in the liquid to facilitate control of the flow conditions and generate different flow regimes. The control of the flow loop is implemented through a fully integrated online computer system, which also handles the data acquisition.

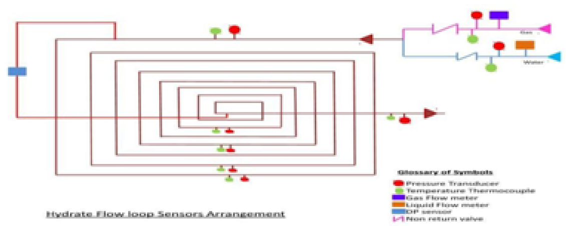

Figure 3.1: Experimental set-up of the test section of flow loop

4. Experiments

4.1. Single Phase Experiments

Once the experimental setup was ready experiments for single phase (that was liquid) was conducted. Water is used as liquid medium and strategy was selected to keep increase the liquid flow rate from 0.25 L/min till 0.28 L/min and observe the behavior of pressure and temperature as shown in figure 7 and 8 respectively and data record for pressure and temperature data points are given below in table 1and 2 respectively.

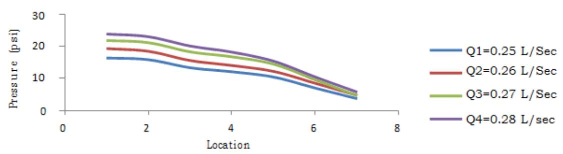

Figure 4.1: Pressure profile for single phase flow

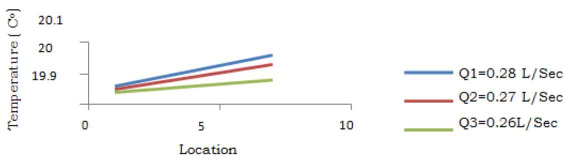

Figure 4.2: Temperature profile for single phase flow

4.2. Two Phase Flow

Similarly, experiments conducted for two phase flow taking water as liquid phase and air as gas phase. The strategy that was obtained for conducting experiments including for each test run keep the liquid flow at constant rate and increasing the flow rate of gas for first test and obtain three data points. Results for first case (TEST -1) where liquid phase was kept constant at 33.23 L/min and gas flow rate was kept on increasing is shown in Table 4.3.

The graphical representation of the experiments in shown in figure 4.3, where liquid phase was kept constant at 21.760 L/min and gas flow rate was kept on increasing is shown in Table 4.4.

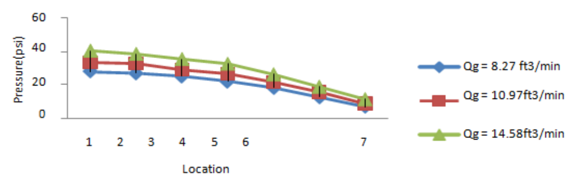

Figure 4.3: Results for Two phases flow TEST-1 Results for first case (TEST -2)

The graphical representation of the experiments in shown in Figure 4.4.

Table 4.1: Data points of pressure for single phase flow

Location	1 Inlet	2	3	4	5	6	7 Outlet
Pressure (psi) at QL = 0.25	16.43	15.90	13.39	12.13	10.47	7.09	3.73
Pressure (psi) at QL = 0.26 (L/S)	19.36	18.51	15.63	14.08	12.23	8.52	4.62
Pressure (psi) at QL = 0.27 (L/S)	21.89	21.21	18.34	16.79	14.50	9.59	4.76
Pressure (psi) at QL = 0.28 (L/S)	23.89	23.07	20.16	18.25	15.42	10.47	5.76

Table 4.2: Data points of temperature for single phase flow

Location	Inlet T_1C^o	2	3	4	5	6	Outlet T_7C^o
Temp. at Q1	19.96	19.76	19.75	20.77	20.18	20.09	20.06
Temp. at Q2	19.9	19.73	19.71	20.68	20.21	20.05	20.03
Temp. at Q3	19.94	19.78	19.69	20.58	20.2	20.02	19.98

Table 4.3: Data record for two phase flow at Ql = 33.23 l/min

Pump inlet air pressure (psi) = 10 and liquid flow rate (L/min) = 33.23							
Location	1 Inlet	2	3	4	5	6	7 Outlet
Pressure (psi) at Qg = 8.27 (ft^3/min)	27.83	26.93	25.16	22.18	18.26	12.53	6.91
Pressure (psi) at Qg = 10.97 (ft^3/min)	33.41	32.8	29.02	26.63	21.64	15.66	8.6
Pressure (psi) at Qg = 14.58 (ft^3/min)	40.45	38.48	35.45	32.63	26.3	18.88	11.39

Table 4.4: Data record for two phase flow at Ql = 21.760 l/min

Pump inlet air pressure (psi) = 10 and liquid flow rate (L/min) = 21.760							
Location	1 Inlet	2	3	4	5	6	7 Outlet
Pressure (psi) at Qg = 6 (ft^3/min)	15.29	14.68	12.5	11.19	9.43	6.01	2.89
Pressure (psi) at Qg = 9.56 (ft^3/min)	24	22.63	20.22	18.06	14.77	10.03	5.175
Pressure (psi) at Qg = 13.5 (ft^3/min)	27.05	26.09	22.83	20.63	16.88	11.81	6.69

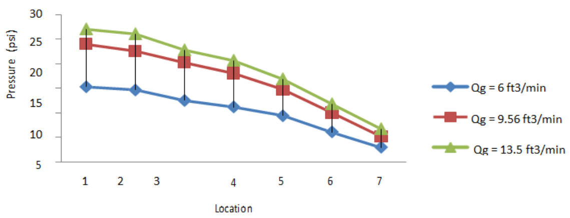

Figure 4.4: Results for Two phase flow TEST-2

4.2.1. Results and Discussion

The above trends of single phase and two phase flow indicates decrease in pressure or increase in pressure drop with length, which is a good indication that pressure in decreasing over length due to a long profile and a lot of elbows, However temperature profile is not much affected because the experiments was conducted at room temperature that do not effect temperature.

5. Initiation of The Visualization of Flow Regimes

One of the most challenging aspects of handling two-phase flows in pipelines is, that they develop different flow patterns. In the horizontal, for a gas-liquid flow, the gas may appear as small amounts of small bubbles in the liquid. This kind of flow occurs when there is a small amount of gas compared to the amount of liquid flowing through the pipe. At the same time, if the liquid flow is fast enough to create a turbulent flow to mix the gas faster into the liquid, then the gas can rise up to the top of the pipeline. Another extreme is, if a huge gas flow rate carries a small flow rate of liquid, then the water will flow as a small film on the pipe wall[16].

5.1. Flow Regimes in Horizontal Pipes

Figure 5.1 illustrates the different two-phase flow patterns in a horizontal pipeline. Stratified smooth flow (SS) has the strongest tendency to occur in horizontal pipes with relatively small amounts of gas and liquid flow rates. If the gas flow rate is increased, waves start to form (SW). These waves can be high enough to reach the top of thepipeline. When that happens, the gas slows down or is even stopped for a moment so that the flow becomes discontinuous, thus leading to slugs (I) or elongated bubbles (EB). Generally, slugs are unwanted in pipelines, because they can create significant pressure fluctuations, and they can also lead to gas and liquid arriving at the processing facilities unevenly, causing tanks to flood. Another important safety issue of slugs is the lower gas density and therefore lower heat capacity compared to the liquid which cools the gas down faster. The lower temperature during periods of high gas content causes the formation of hydrates in the pipeline more easily as explained in chapter 2.2. Additionally, the higher liquid velocity accelerates the corrosion in pipes [17].

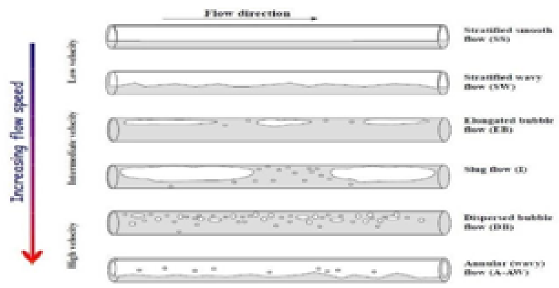

Figure 5.1: Two-phase (gas/liquid) flow in Horizontal pipes

The normal way of presenting the results of the visualization of the different flow patterns is to plot them in a graph. The axes of this flow map represent the flow rates of the two phases liquid and gas. An alternative is to plot total mass flux on one axis and the mass fraction of the flow which is vapor or gas on the other axis. Figure 5.2 presents the flow regime map for horizontal pipelines Taitel and Dukler [18] ,[19].

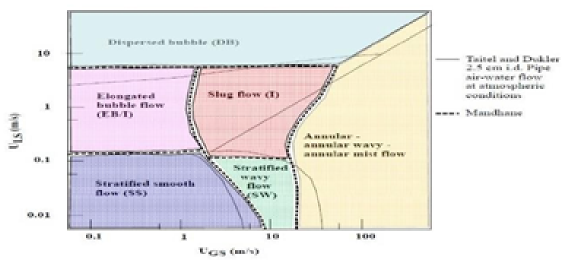

Figure 5.2: Flow regime map for Horizontal pipelines

Table 5.1: Flow Regimes calculation worksheetCalculation for Flow Regimes

Pipe diameter (ft)		0.75		
Pipe radius (ft)		0.375		
Pipe area (ft^2)		0.44184375		
Liquid flow rate (L/min)		21.76		
Liquid flow rate (ft^3/sec)		0.01279488	0.01953924 m^3/s	
Superficial velocity		0.028957929	0.044222058 m/s	
Gas Flow rate (ft^3/min)	Gas flow rate (ft^3/sec)	Superficial velocity (ft/sec)	Flow Pattern Experimental	Flow Pattern Theoretical
6	0.1	0.226324351	Wavy /Intermittent	Slug/wavy
9.56	0.159333333	0.360610133	Wavy /Intermittent	Slug/wavy
13.5	0.225	0.50922979	Wavy /Intermittent	Slug/wavy
8.27	0.137833333	0.311950397	Wavy /Intermittent	Slug/wavy
10.97	0.182833333	0.413796355	Wavy /Intermittent	Slug/wavy
14.58	0.243	0.549968173	Wavy /Intermittent	Slug/wavy

5.2. Experimnets for The Determination of Flow Regimes

Experiments for the determination of flow regimes are conducted and results are shown in the work sheet below. The difference in flow regimes experimental (Visualization) and analytical (By Taitel - Dukler horizontal flow map) may be due to the human error in taking measurements, work on this issue is under doing to rectify this issue.

5.3. Comparison of Using CO_2 and Air as A Second Phase (Pressure)

Table 5.2: Air – CO_2 results comparison

Pressure Drop Using CO_2 (psi)			
Increasing gas flow rate			
6.14	9.52	10.99	16.26
Pressure Drop Using Air			
Increasing gas flow rate			
13.48	24.39	25.47	26.64

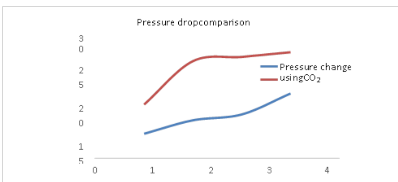

Figure 5.3: Pressure drop comparison (Air – CO_2)

5.4. Comparison of Using CO_2 and Air as A Second Phase (Temperature)

Table 5.3: Air – CO_2 results comparison

Gas Flow Rate CO_2 (ft^3/min)	Gas Flow Rate Air (ft^3/min)	Temperature Drop (CO_2) C^o	Temperature Drop (Air) C^o
0.01477	5.99	0.11	0.5
0.01482	8.12	0.17	0.41
0.01489	14.15	0.15	0.40
0.01491	17.11	0.22	0.40

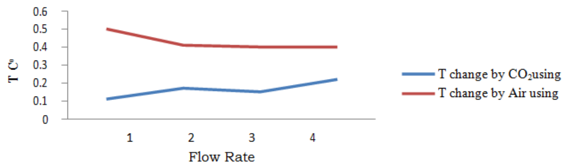

Figure 5.4: Temperature drop comparison (Air – CO_2)

6. Conclusion and Recommendations

A multiphase flow loop has been developed and experiments conducted initially for single phase, later for two phase. Calibration of sensors has been already done. This flow loop is a lab scale experimental facility to study the multiphase flow and as well as hydrate induction process. To study the hydrate formulation processing flow loop

needs to place in a cold room which is also available at Memorial university fluid dynamics lab, but under renovation these days, expected to become operational by later August'2016. Soon cold room is obtained experiments to study hydrate processing will be conducted, and results will be presented in 1st International Conference on Chemical, Petroleum, and Gas Engineering (CCPGE 2016).

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