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Study of Slug Flow in Undulated Horizontal Wells

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Abstract

Terrain induced slugging have become more common as the petroleum industry matures. Late-life fields, deepwater fields and marginal subsea tiebacks to existing facilities are prone to terrain induced slugging. Extended reach wellbore, including snake wells, fish-hook wells and undulated wells are relative new technologies used to drain otherwise not economically feasible hydrocarbon zones. These well trajectories are, however, prone to terrain induced slugging since they can resemble a pipeline-riser system containing low spots over large distances to accumulate large liquid slugs. Conventional methods of handling slug flow includes choking, gas injection at the riser base or installation of a slug catcher. These methods have drawbacks of reducing production rates, requiring large amounts of gas or high cost. Lately, automatic slug control based on feedback control systems can suppress the slugs, but becomes unstable when operating conditions change.

This study attempts to assess the potential of a rotating device to mechanically break down liquid slugs in the gas-liquid interface and/or influence multiphase flow in any significant and beneficial way. Experiments were performed by placing the device in vertical, inclined and horizontal sections. It was seen that the device in some cases influenced the slug flow behaviour, especially in horizontal flow direction. The frequency increased while the average slug length decreased significantly over a short distance. It was further seen that the impact in vertical direction and bend sections were insignificant for the test conditions in this study.

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Nomenclature

Symbols

α	Phase fraction
β	Inclination
μ	Viscosity
σ	Surface tension
C	Choke coefficient
D	Pipe diameter
F	Force
f_s	Slug Frequency
g	Gravitational acceleration
h	Height
L	Length
P	Pressure
t	Time
u	Flow velocity
w	Mass flow rate
α'	Gas holdup in gas cap
$\dot{m}$	Mass velocity
ρ	Density
f_L	Liquid friction factor
K	Proportionality constant
Re	Reynolds number
S	Perimeter over which stress acts
s	Jeffreys' sheltering coefficient
v	Kinematic viscosity

Subscripts

f	Film
G	Gas
i	Any phase within flow system, also interface
L	Liquid
m	Mixture
P	Pipeline
s	Slug
t	Total
u	unit
B	Back
E	Entrance
sep	Separator
SG	Superficial gas
SL	Superficial liquid

Abbreviations

PI	Proportional and integral
PID	Proportional, integral and derivative
PIG	Pipeline inspection gauge
PT	Pressure and temperature
RPM	Rounds per minute

Chapter 1

Introduction

1.1 Background

Slug flow is considered a major flow assurance challenge characterized by alternation of liquid and gas flow. Large variations in flow rates and pressure is a concern for the reservoir integrity alongside corrosion, damage to pipelines and flooding of first stage separator. Terrain induced slugs can originate from complex well geometries, pipeline topography and low spots in flexible risers. In addition, slugs are created from hydrodynamic instability caused by flowing conditions. Terrain induced slugging have become more common as the petroleum industry matures. Late-life fields, deepwater fields and marginal subsea tiebacks to existing facilities are prone to terrain induced slugging. Extended reach wellbore, including snake wells, fish-hook wells and undulated wells are relative new technologies used to drain otherwise non-profitable reservoirs. These well trajectories are, however, prone to terrain induced slugging since they can resemble a pipeline-riser system containing low spots over large distances to accumulate large liquid slugs.

1.2 Problem formulation

Controller systems used to suppress slugs rely heavily on correct field data and models to function properly and suppress the slugs. After some time the operating conditions change and the control system becomes unstable. The operators, instead of tuning the controller system, often change to the manual choke when the controller becomes unstable (Jahanshahi, 2013). Other ways of mitigating effects of slugging are slug catchers, topside choking, gas injection at the riser base and subsea processing. Individual drawbacks of these mitigation techniques are discussed in Section 3.5. In this thesis, the potential of a device to mechanically break down or alter the slug flow behaviour is tested in six experiments.

1.3 Scope and objectives

Scope of this thesis is study of multiphase flow, slug flow and experimental investigation of a rotating device to mechanically break down slugs and/or alter the slug behaviour in any way.
Objectives for this thesis are;

- Review literature to get fundamental understanding of multiphase flow and slug flow in particular.
- Study flow in small scale flow loop and identify flow conditions for slug flow.
- Assess impact from device on slug flow behaviour in experiments.
    - Bend, vertical and horizontal sections
    - Identify optimal placements

1.4 Outline

- Chapter 2 reviews literature of multiphase flow focusing on concepts used in multiphase flow, flow regimes encountered in horizontal and vertical flow direction and flow regime maps for horizontal and vertical flow.
- Chapter 3 reviews slug flow focusing on why slug flow is encountered in various industrial applications, models describing slug flow and special emphasis on terrain induced slugging, considered to be largest slugs encountered. Several mitigation techniques are discussed as well as two cases from the North Sea are reviewed.
- Chapter 4 summarizes the experimental work. Three flow loops were used to evaluate the use of a turbine in horizontal section, inclined section and vertical section.
- Chapter 5 Summarizes the results from the experimental study.

- Chapter 6 discusses the experimental results.
- Chapter 7 concludes the work of the experimental study and suggests future work.

Chapter 2

Multiphase Flow

Multiphase flow is simultaneous flow of materials in different phases, either as gas, liquid or solid with presence of minimum two phases. For petroleum production, presence of oil and gas at the same time is a common multiphase flow system. This is the case when gas-lift is used in oil wells or when the conditions are such that the produced hydrocarbons are gas and liquid.

Conditions for a multiphase petroleum system is defined with a phase diagram. The phase diagram illustrates conditions for a given system as function of pressure and temperature. A two-phase flow system is the condition within the envelope in Figure 2.1.

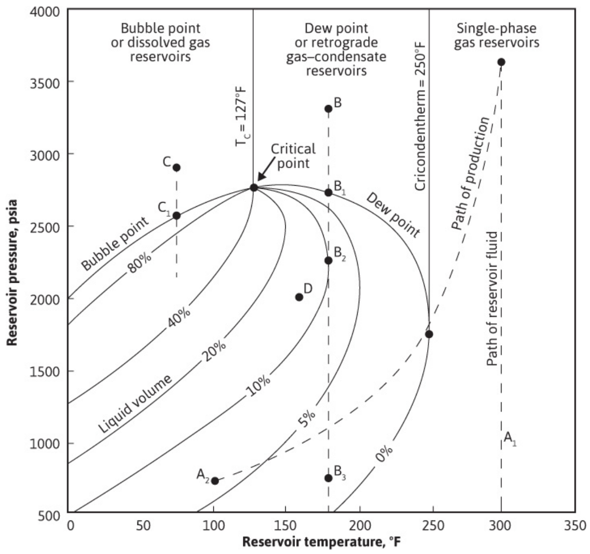


Figure 2.1: Typical phase diagram for hydrocarbons as function of pressure and temperature. Multiphase components are found within the boundary of the envelope (Terry and Rogers, 2014)

As the pressure decreases while transporting hydrocarbons from reservoir to surface, single-phase systems can become two-phase flow system as the pressure depletes below the bubble or dew point. This is the case when pressure depletes in an oil reservoir, when pressure and temperature depletes in a wet gas reservoir or when pressure depletes in gas-condensate reservoirs. Gas can be dry in the reservoir with high pressure and temperature conditions, but saturated with oil or water in gas phase. When the gas is transported, the temperature and pressure decrease and saturated oil or water condensates. Reservoir pressure depletes over time resulting in multiphase flow systems at new reservoir conditions that initially were single-phase flow systems.

2.1 Concepts of multiphase flow

2.1.1 Velocity

The phase velocity expresses the real velocity of each phase in the flow system. Determination of the phase velocity requires knowledge of area occupied by the specific phase, which can change throughout the system. The expression for the phase velocity is:

$$u_i = \frac{Q_i}{A_i} \tag{2.1}$$

As determination of the phase velocity requires detailed information about the flow at a specific point, the superficial velocity is introduced as it only requires knowledge about the pipe size and the volumetric flow rate of the phase. This makes the superficial velocity recommended for multiphase flow. The superficial velocity is expressed as:

$$u_{si} = \frac{Q_i}{A} = \alpha_i u_i \tag{2.2}$$

The mixture velocity is the average flow velocity and can be expressed with the superficial velocities in the following way:

$$u_m = \sum_N u_{Nsi} \tag{2.3}$$

2.1.2 Fluid fractions

Void fraction

Void fraction is the fraction occupied by gas in the flow system defined geometrically either by relative length, cross-sectional area or volume. The common method to quantify the void fraction is with the cross-sectional void fraction (Thome, 2004) expressed as:

$$\alpha_G = \frac{A_G}{A} \tag{2.4}$$

Liquid holdup

Liquid holdup is the fraction occupied by liquid in the flow system. The heavier liquid usually flows at a lower speed than the lighter gas and is for that reason more held up, hence liquid holdup. The liquid holdup is expressed as:

$$\alpha_L = \frac{A_L}{A} \tag{2.5}$$

The void fraction and liquid holdup are linked by the fundamental relation in air-water flow:

$$\alpha_L + \alpha_G = 1 \tag{2.6}$$

The fractions changes along the flow due to geometrical configurations, flow regime, pipe size and fluid properties.

2.1.3 Pressure gradients

The homogeneous flow model (Thome, 2004) states that the total pressure drop gradient in multiphase flow is expressed as:

$$\frac{dp}{dx} = \left(\frac{dp}{dx}\right)_f + \left(\frac{dp}{dx}\right)_h + \left(\frac{dp}{dx}\right)_a \tag{2.7}$$

This means that the total pressure drop is caused by friction, head loss and acceleration. The friction term is expressed by (Thome, 2004):

$$\left(\frac{dp}{dx}\right)_f = \frac{2}{D} C \left(\mathrm{Re}_m\right)^{-n} \rho_m u_m^2 \tag{2.8}$$

Where C and n are dependent of the Reynolds number in the following way (Filip et al., 2014):

$$\mathrm{Re} = \begin{cases} < 2000, & C = 16 \quad n = 1 \\ 2000 \leq \mathrm{Re} \leq 20\,000, & C = 0.079 \quad n = 0.25 \\ \geq 20000, & C = 0.046 \quad n = 0.2 \end{cases}$$

The mixture density is expressed as:

$$\rho_m = \rho_L \alpha_L + (1 - \alpha_L)\rho_G \tag{2.9}$$

Further, the hydrostatic head is expressed as (Thome, 2004):

$$\left(\frac{dp}{dx}\right)_h = \rho_m g \sin\beta \tag{2.10}$$

The inclination β is given with respect to horizontal. Furthermore, the acceleration term is expressed as (Thome, 2004):

$$\left(\frac{dp}{dx}\right)_a = \frac{d(\dot{m}_t/\rho_m)}{dx} \tag{2.11}$$

The model is a generalisation of a single phase flow model to a multiphase flow model by assuming completely homogeneous flow. Other correlations have been found for flow regimes where homogeneous flow is not the case.

2.2 Flow regimes

Interaction between phases in multiphase flow results in various flow patterns with different characteristics. Flow regimes are these patterns of flow and vary depending on operating conditions, such as flow rates, fluid properties, geometry of pipe and pressure differentials. Prediction of flow regime can be difficult and several methods are used including analytical, empirical and numerical solutions (Li, 2007). As the physical models behind flow transitions are not completely understood, predictions include high uncertainty. Transition between flow regimes have no sharp boundaries but instead changes smoothly between the regimes (Corneliussen et al., 2005).

2.2.1 Vertical Flow

Multiphase flow in vertical direction are classified as bubble, dispersed bubble, slug, churn or annular flow depending on the interaction between the phases, individual velocities, densities and viscosities.

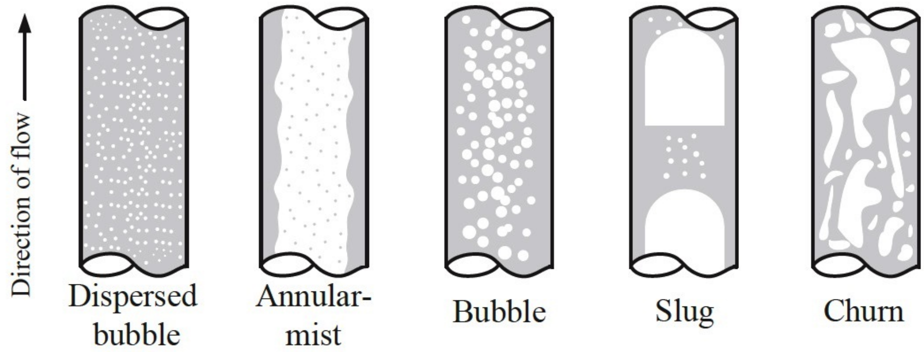


Figure 2.2: Flow regimes in upward flow direction in a vertical pipe (Malekzadeh, 2012)

Bubble flow

Bubble flow is characterized by continuous liquid flow containing small gas bubbles. Little attention has been given bubble flow as there are few industrial applications and challenges with this type of flow. Bubble flow occurs at relatively low velocities. Distinguishing between bubble flow and dispersed bubble flow can be a challenge, difference being the shape of the gas bubbles. While the bubbles in dispersed flow are spherical or nearly spherical, the gas bubbles in bubble flow are ellipsoidal or pulsating in their shape (Andreussi et al., 1999).

Slug Flow

The gas phase flows as large bubbles separated by liquid slugs. The bubbles are bullet-shaped, often referred to as Taylor bubbles in the literature. The gas phase travels at higher velocities than the liquid phase resulting in liquid holdup. Both gas and liquid phase contributes significantly to the pressure drop in this regime. Compared to bubble flow, the velocity of the gas phase is generally higher.

Churn Flow

Churn flow is considered to be the result of transition between slug and annular flow. The liquid slugs between the gas bubbles can be discontinuous or disappear, while the gas phase becomes continuous. The pressure drop becomes more dependent on the gas phase, rather than the liquid phase (Bai and Bai, 2012). Compared to slug flow, churn is more chaotic and disordered as well as gas phase velocity is increased.

Annular-mist flow

Annular flow is characterized by the gas phase flowing in the middle of the pipe with small droplets of liquid in the stream. The rest of the liquid flows at the pipe wall as a liquid film. This flow regime is desired because of the flow stability. Mist flow is the regime encountered when the gas velocity becomes very high. The liquid film is thinned by the shear of the gas, until eventually all the liquid is entrained as droplets in the continuous gas phase (Thome, 2004).

2.2.2 Horizontal Flow

Opposed to vertical flow, multiphase flow in the horizontal direction are classified as either dispersed bubble, annular, stratified, slug and elongated bubble flow as illustrated in Figure 2.3.

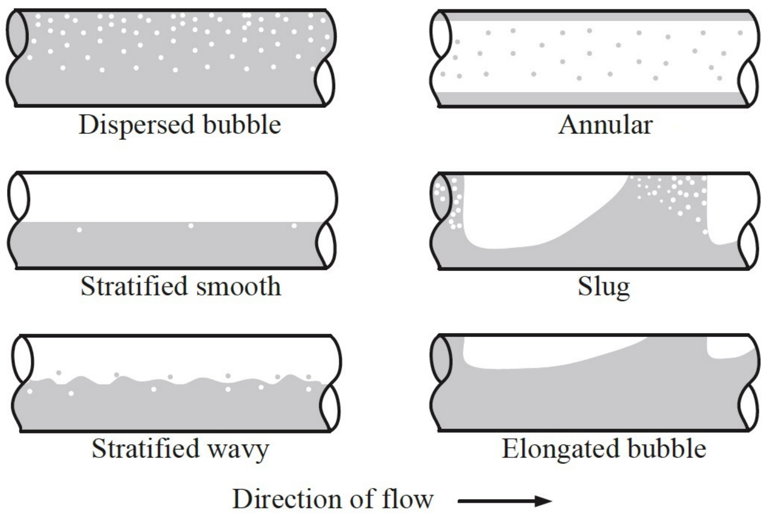


Figure 2.3: Flow regimes in horizontal pipe flow (Malekzadeh, 2012)

Dispersed bubble flow

Dispersed bubble flow is characterized by small dispersed gas bubbles moving along the flow in otherwise continuous flow of liquid. The size of the dispersed bubbles subside with increasing velocity of the continuous liquid phase (Bai and Bai, 2012).

Stratified flow

The gas and liquid phase in stratified flow are separated with an interface between the phases. Smooth stratified flow is characterized with a smooth interface, whereas stratified wavy flow is characterized by waves moving in the flow direction. Waves arise as the result of greater gas velocity creating instabilities in the interface.

Slug flow

Slug flow in horizontal direction is characterized by bullet-shaped gas bubbles travelling along the flow direction separated by liquid slugs. Gas bubbles travel at the top of the pipe due to low density of the gas bubbles.

Elongated bubble flow

Elongated bubble flow contain small dispersed gas bubbles moving through a continuous liquid phase. The flow pattern is similar to the flow pattern of slug flow, but the size of the bubbles are generally smaller with lower velocity. Elongated bubbles are formed when smaller bubbles coalesce, often referred to as plug flow in the literature.

Annular flow

Similar to annular flow in vertical direction, the gas phase moves along the flow direction in the centre of the pipe with some liquid entrained as small droplets. The rest of the liquid flows along the pipe wall as a liquid film.

2.3 Flow Regime maps

Flow regime maps are used to predict flow regime for a multiphase flow system. The maps are often based on experimental results in laboratory resulting in poor agreement or high uncertainty when used for other system configurations. The map by Baker (Baker, 1953) was used for designing pipelines, while the data was gathered from experiments in laboratories. This made for high uncertainty when used. Later developments used data from flow data banks to develop flow regime maps, although the data sets were in most cases results of visual observations.

2.3.1 Baker horizontal flow regime map

The flow regime map proposed by Baker (Baker, 1953) was based on correction factors and utilizing the available data at the time. The correction factors were necessary as most of the available data at the time was for air-water flow at atmospheric conditions and the flow regime map was used for designing pipelines containing oil and gas flow. Bakers fluid property correction factors were written as:

$$\lambda = \left[\left(\frac{\rho_G}{\rho_{air}} \right) \left(\frac{\rho_L}{\rho_{water}} \right) \right]^{1/2} \tag{2.12}$$

and

$$\psi = \left(\frac{\sigma_{water}}{\sigma} \right) \left[\left(\frac{\mu_L}{\mu_{water}} \right) \left(\frac{\rho_{water}}{\rho_L} \right)^2 \right]^{1/3} \tag{2.13}$$

Bakers work resulted in the following flow regime map for horizontal flow:

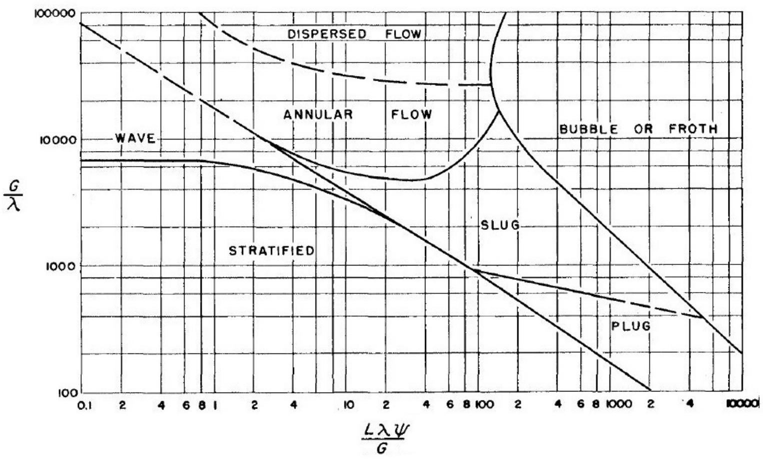


Figure 2.4: Baker flow regime map (Baker, 1953)

It is important to know that the transitional zones were rather broad and the map suffered from not having a basis in mechanisms causing transitions as the map was made from observations by Baker.

2.3.2 Mandhane horizontal flow regime map

Mandhane *et al.*(Mandhane et al., 1974) tested several proposed models against flow pattern observations gathered from the UC multiphase Pipe Flow Data Bank. Observations in the data bank were results of visual inspections and the observers own interpretation of the flow, possibly resulting in some error. After comparison with experimental data, they proposed their own flow pattern map which represented an extension of the work by Govier and Aziz (Aziz and Govier, 1972) in better agreement with experimental data.

The proposed flow pattern map was based on air-water flow data following attempts to apply physical properties for correction purposes. Their approach was new, but with the extensive amount of data available, it was possible. The base for the diagram is a log-log plot with the superficial phase velocities as coordinate axes, thereby avoiding complex parameters in the map.

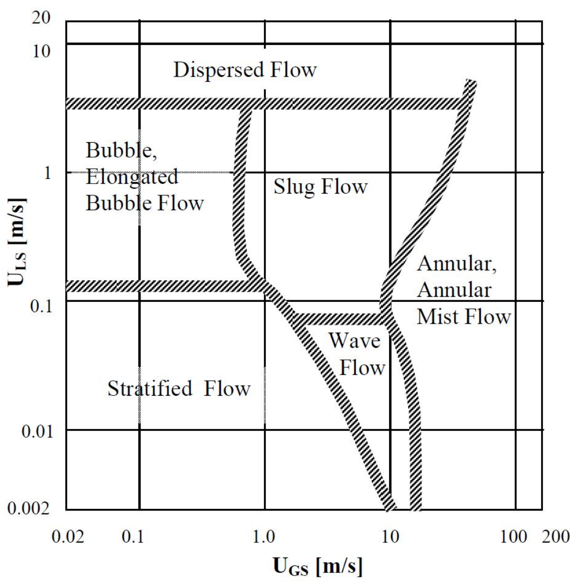


Figure 2.5: Mandhane flow regime map (Mandhane et al., 1974)

Flow pattern observations were basis for the transitions in the air-water system. The diagram is an average compromise of the variety of combinations of pipe diameters and physical properties. The model was better than any of the other models examined when considering air-water data. The proposed map tends to be more accurate when the diameter is less than 2 inches because most of the observations in the data bank were within this range.

2.3.3 Taitel and Dukler horizontal flow regime map

The published model by Taitel and Dukler (Taitel and Dukler, 1976) is a combination of experiment and theory to a model without having to be completely empirical, thus removing the need for correlations of pure curve fit type. Their model was fairly simplified with the choice of specific assumptions.

Their approach was to use a theoretical model based on physical concepts to predict the transitions between flow regimes. The variables influencing transitions were believed to be gas and liquid mass flow rates, the properties of the fluids, pipe diameter and the inclination. The considered flow regimes were smooth stratified, wavy stratified, intermittent(Elongated bubble flow and slug flow), annular and dispersed bubble flow with emphasizes on transitions between the regimes. Analysis starts from the condition of stratified flow, followed by determining the mechanism causing transition. Starting from stratified smooth flow, they found transition to stratified wavy to take place when:

$$u_G \geq \left[\frac{4v_L(\rho_L-\rho_G)g\cos\beta}{s\rho_G u_L}\right]^{1/2} \tag{2.14}$$

Further, they expressed the transition from stratified to intermittent or annular dispersed as:

$$u_G = \left(1-\frac{h_L}{D}\right)\left[\frac{(\rho_L-\rho_G)g\cos\beta A_G}{\rho_G S_i}\right]^{1/2} \tag{2.15}$$

Distinguishing between transition intermittent flow and annular dispersed flow was found to be affected by the h_L/D-ratio. In the paper it was suggested transition to intermittent flow when $h_L/D < 0.5$, otherwise transition to annular dispersed flow. A modified criterion of $h_L/D < 0.35$ was later suggested to account for gas holdup in the liquid slug (Barnea et al., 1982). Further, they found transition between intermittent flow and dispersed bubble flow to happen when:

$$u_L > \left[\frac{4A_G g\cos\beta(\rho_L-\rho_G)}{S_i\rho_L f_L}\right]^{1/2} \tag{2.16}$$

Figure 2.6 illustrates the resulting flow regime map from the study, including a comparison with the Mandhane plot from Figure 2.5, indicating good agreement between the flow regime maps.

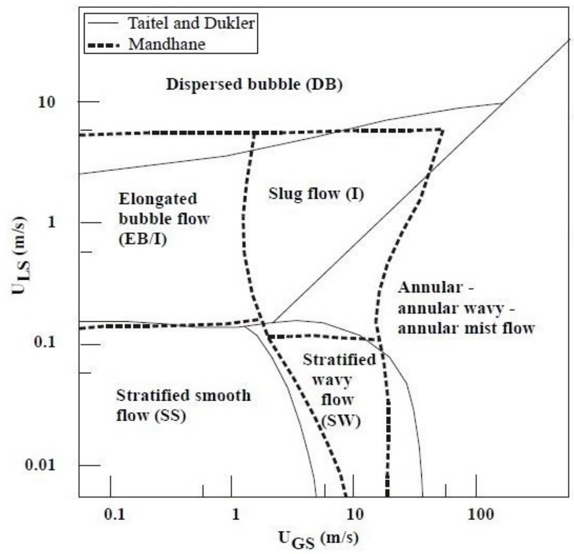


Figure 2.6: Taitel and Dukler horizontal flow regime map for a 2.5 cm inner diameter pipe, air-water flow at atmospheric conditions. For comparison, the Mandhane plot is added (Taitel and Dukler, 1976)

2.3.4 Taitel, Bornea and Dukler vertical flow regime map

Taitel *et al.* (Taitel et al., 1980) proposed a model for a vertical flow regime map based on transition boundaries between the five basic flow patterns found in vertical gas-liquid flow. They found that the transitions were affected by the flow rate pair, fluid properties and pipe size. Unlike many already existing flow pattern maps, which often had their basis in experimental data, they used physical mechanisms to describe the transitions between flow regimes.

They started by looking at the existence of bubble flow and found the following expression had to be fulfilled for bubble flow existence:

$$\left[\frac{\rho_L^2 g D^2}{(\rho_L-\rho_G)\sigma}\right]^{1/4} \leq 4.36 \tag{2.17}$$

It is seen by the statement that bubble flow is heavily dependent on the diameter of the pipe, and if the pipe diameter is sufficiently high, bubble flow is not existing. Further, they studied the mechanism that caused transition from bubble flow to slug flow and found the following expression to be fulfilled for bubble to slug transition:

$$u_{SL} = 3.0 u_{SG} - 1.15\left[\frac{g(\rho_L-\rho_G)\sigma}{\rho_L^2}\right]^{1/4} \tag{2.18}$$

Further, they found that the transition from bubble flow to dispersed bubble flow was expressed with the following equation:

$$u_{SL}+u_{SG}=4.0\left\{\frac{D^{0.492}(\sigma/\rho_L)^{0.089}}{\nu_L^{0.072}}\left[\frac{g(\rho_L-\rho_G)}{\rho_L}\right]^{0.446}\right\} \tag{2.19}$$

Transition from slug flow to churn flow was found to be expressed as:

$$\frac{l_E}{D}=40.6\left(\frac{u_m}{\sqrt{gD}}+0.22\right) \tag{2.20}$$

The transition boundary to annular flow was found to be expressed as:

$$\frac{u_{SG}\rho_G^{1/2}}{\left[g(\rho_L-\rho_G)\sigma\right]^{1/4}}=3.1 \tag{2.21}$$

Equation 2.21 shows that annular flow is independent of the liquid flow rate and pipe diameter. The equations above was used to make the flow regime map illustrated in Figure 2.7.

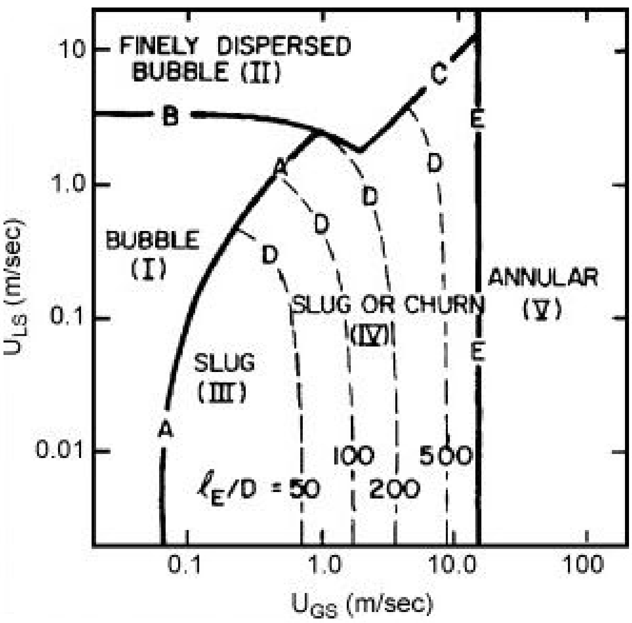


Figure 2.7: Bornea, Taitel and Dukler vertical flow regime map for a 5.0 cm inner diameter pipe, air-water flow at atmospheric conditions, $\sigma=10\text{N/cm}^2$ and varying l_E/D for Slug-Churn transition (Taitel et al., 1980)

Chapter 3

Slug Flow

Slug flow is a multiphase flow regime characterized by alternating flow of gas and liquid slugs. Slug flow in the well and pipelines are undesirable because of large fluctuations in both pressure and flow rates, ultimately leading to decrease in the overall production. As the behaviour of slug flow is complex in nature, accurate predictions are challenging, especially as there are several parameters affecting the flow behaviour. Slug flow in wells and pipelines are common because of hydrodynamic instability, complex well geometry, topography and flexible riser configurations. As the current mitigation techniques reduce overall production rates or require additional equipment taking up large spaces, new mitigation techniques are desired. Developments of deepwater and marginal subsea tiebacks increase the likelihood of slug flow as the terrain becomes more complex and the distance to processing facility increases.

3.1 Slug flow related problems

Slug flow is associated with problems at the receiving end in the transport of hydrocarbons from the reservoir to processing facility along with damage to pipes and equipment in the wells. Flooding of the separator at the receiving can happen when model predictions are wrong or slugging potential not properly studied in the design phase resulting in bigger slugs than the processing equipment can handle. As a consequence, the wells can get shut in, resulting in no production. Relatively large pressure variations are normal in slug flow as the flow alternates between gas and liquid. Terrain induced slugs increases the pressure as the slug grows, but the pressure is quickly reduced when the slug is produced. Long periods of low production leads to temperature decrease in the pipelines leading to wax formation and ultimately hydrates (Skofteland et al., 2007).

3.2 Hydrodynamic slugging

Hydrodynamic slugs are generated in horizontal pipelines due to instabilities of the waves in the gas-liquid interface. The flow must be stratified at certain flowing conditions for hydrodynamic slugs to occur. The growth of the wave is result of Kelvin-Helmholtz instability lifting the interface between the gas-liquid phase upwards in the pipe. The instability condition takes place because of differences in gas and liquid velocities. Figure 3.1 illustrates the formation of hydrodynamic slugs from an unstable wave growing to a liquid slug.

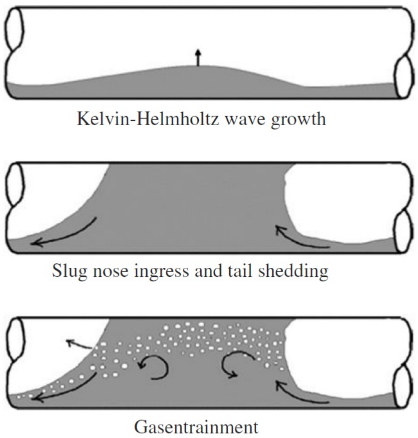


Figure 3.1: Formation of hydrodynamic slug (Feesa, 2003)

The Kelvin-Helmholtz instability criterion is mathematically expressed as (Taitel and Dukler, 1976):

$$u_G > \left[\frac{g(\rho_L - \rho_G) h_G}{\rho_G} \right]^{1/2} \tag{3.1}$$

Equation 3.1 shows that when the gas flow velocity is sufficiently high, waves will grow and slugs can be formed.

3.2.1 Slug unit cell

The concept of slug unit cell is used to predict slug flow characteristics starting with one unit cell and then generalize for a pipe section. The slug unit cell is an idealized slug that has been fully established. The assumption of a fully established slug simplifies the l_s-term as the velocity of the liquid slug will move at a speed close to the mixing velocity (Dukler and Hubbard, 1975).

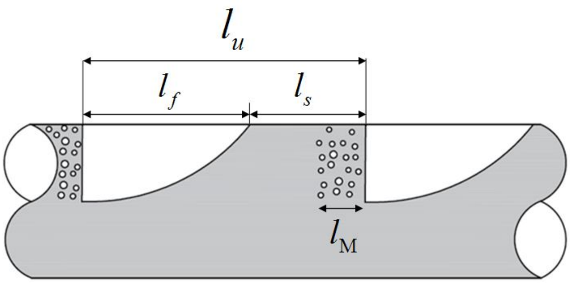


Figure 3.2: Slug unit cell for horizontal flow, l_u is the length of one unit cell, l_f is the length of the liquid film, l_s is the length of the liquid slug and l_M is the mixing zone within the liquid slug (Dukler and Hubbard, 1975)

The slug unit is divided into two parts, the liquid slug part, also called the the slug body with length l_s and the liquid film with length l_f. It is seen that the length of one unit is expressed as:

$$l_u = l_f + l_s \tag{3.2}$$

3.2.2 Pressure drop

Utilizing the properties of the slug unit cell, the pressure drop within a slug cycle can be studied.

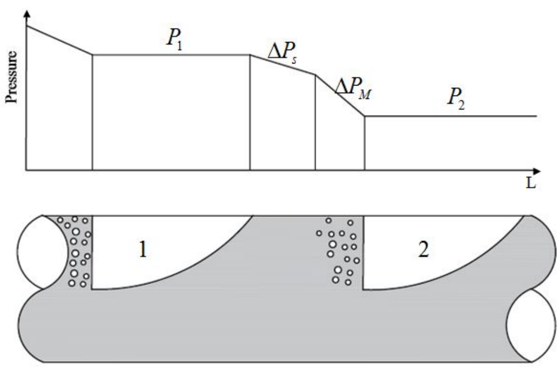


Figure 3.3: Idealized pressure drop in slug flow utilizing the concept of unit cell (Dukler and Hubbard, 1975)

Two contributions to the pressure drop across the slug is observed. ΔP_s is the friction in the liquid slug from overcoming wall shear in the back of the slug. ΔP_M is pressure drop due to acceleration of the liquid film to slug velocity in the mixing zone. The total pressure drop over the slug is expressed as (Dukler and Hubbard, 1975):

$$\Delta P_t = \Delta P_s + \Delta P_M \tag{3.3}$$

3.2.3 Slug frequency

Knowledge of slug frequency is essential for the design of the processing equipment, especially separator design (Zabaras et al., 1999). Knowledge of the slug frequency gives insight to the characteristics of the slug flow, such as slug length, pressure drop and the velocity. The various models developed are based on empirical correlations or mechanistic models. Most available empirical correlations are derived from air-water systems in flow loops with pipe diameter usually smaller than 2 inches. As slug frequency is influenced by several flow variables, the empirical models lack accuracy over a broad range of flowing conditions as they usually only accounts for a few variables in the models. The slug frequency defines the number of slugs passing through a specific point in the pipe within a period of time.

Gregory and Scott (Gregory and Scott, 1969) conducted measurements of slug frequency in a 3/4" pipe for CO_2-water system. Their correlation resulted in the following equation for slug frequency:

$$f_s = 0.0226\left[\frac{u_{SL}}{gD}\left(\frac{19.75}{u_m} + u_m\right)\right]^{1.2} \tag{3.4}$$

Heywood and Richardson (Heywood and Richardson, 1979) measured instantaneous values of liquid holdup for air-water flow in a 1.65" horizontal pipe by utilizing gamma-ray techniques. Their work resulted in the following correlation:

$$f_s = 0.0434\left[\frac{u_{SL}}{u_m}\left(\frac{2.02}{D} + \frac{u_m^2}{gD}\right)\right]^{1.02} \tag{3.5}$$

Shell Slug Frequency Correlation (Stapelberg and Mewes, 1994) was derived by curve-fitting the data of Heywood and Richardson, getting the following relation for the slug frequency:

$$f_s = \frac{0.048\left(\frac{u_{SL}}{\sqrt{gD}}\right)^{0.81} + 0.73\left(\frac{u_{SL}}{\sqrt{gD}}\right)^{2.34}\left[\left(\frac{u_{SL}}{\sqrt{gD}} + \frac{u_{SG}}{\sqrt{gD}}\right)^{0.1} - 1.17\left(\frac{u_{SL}}{\sqrt{gD}}\right)^{0.064}\right]^2}{\sqrt{\frac{D}{g}}} \tag{3.6}$$

The correlation was found to give good agreement with measured data for a 4" air-water inclined flow loop. Zabaras model (Zabaras et al., 1999) represented an extension of the Gregory and Scott correlation, implementing inclination angle from horizontal. The correlation by Zabaras resulted in the following slug frequency equation:

$$f_s = 0.0226\left[\frac{u_{SL}}{gD}\left(\frac{19.75}{u_m}+u_m\right)\right]^{1.2}\left[0.836+2.75\sin^{0.25}(\beta)\right] \tag{3.7}$$

Manolis *et al.* (Manolis et al., 1995) collected data for air-water flow at various pressures using the approach adopted by Gregory and Scott and proposed the following correlation for slug frequency:

$$f_s = 0.0037\left[\frac{u_{SL}}{gD}\left(\frac{u^2_{m,min}+u^2_m}{u^2_m}\right)\right]^{1.8} \tag{3.8}$$

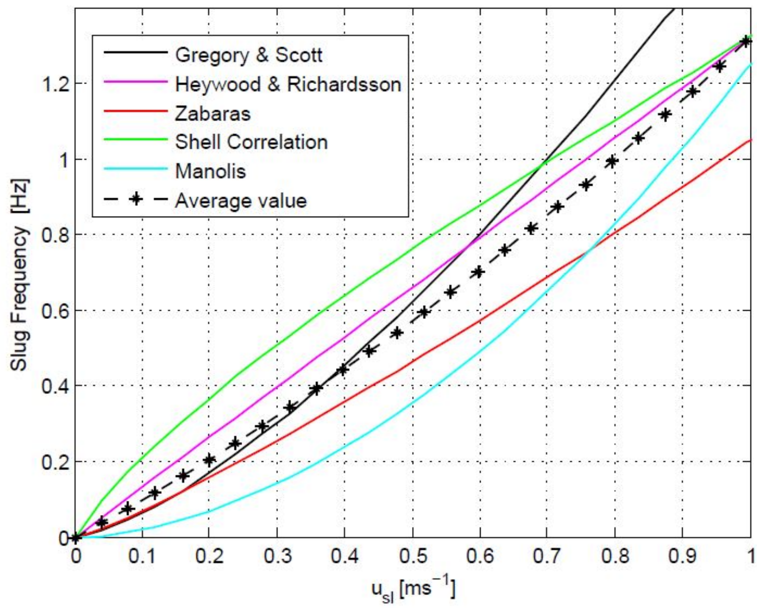


Figure 3.4: Slug frequency as function of superficial liquid velocity for discussed models with a 4.0 cm inner diameter pipe, $u^2_{m,min} = 15.5\,\mathrm{m^2\,s^{-2}}$ and $u_{SG} = 3.1831\,\mathrm{m\,s^{-1}}$

Gokcal *et al.* (Gokcal et al., 2009) conducted slug frequency experiments with high viscosity oil ranging from 0.181 to 0.589 Pa·s and found that the slug frequency was significantly affected by the liquid viscosity. This is a drawback with the models presented here as none of them includes the liquid viscosity in addition to other influencing parameters.

3.3 Operational induced slugs

Operational induced slugs are created when flow transforms from steady state to transient state. These slugs occur in Start-up of wells, when the flow rates are changed and during pigging operations. The slugs develop because the liquid velocity is increased which accumulates more liquid and the slugs grow.

A PIG is sent through the pipelines to remove debris and wax formation at the inner wall of the pipeline. The PIG pushes all the liquid in front to the outlet, a process where a large liquid slug is accumulated in front of the PIG.

3.4 Terrain induced slugging

Terrain induced slugging occurs when the geometry allows for blockage of gas in a low spot and liquid accumulation. Gas blockage can happen when gas-liquid flow enters a riser from the pipeline, in fish-hook wells, in complex in snake wells, undulating wells, due to pipeline topography, in the riser, and in extended reach wells. Terrain induced slugging is considered most critical in the case where gas-liquid flow enters a vertical riser, called severe slugging. The size, in terms of diameter, is considerably larger for the pipelines and riser compared to downhole equipment, thereby making the conditions for severe slugging to occur. Terrain induced slugging occurs at relatively low gas and liquid flow rates as the liquid has the tendency to accumulate at a low spot and blocking free passage for the gas phase (Malekzadeh, 2012). The characteristics of terrain induced slugs depend on many parameters such as wellbore geometry, pipeline topography, reservoir fluid properties, pressures, production rate and fluid dynamics.

Terrain induced slugs create large variations in both pressure and flow rates. Figure 3.5 illustrates how the pressure, liquid flow rate and gas flow rate vary over one slug cycle in a pipeline-riser configuration. It is seen that the pressure increases when the slug builds in the riser. When the slug reaches the top of the riser, the pressure is stable until the gas penetrates the riser base and starts flowing into the riser. When the gas enters the riser, the pressure is quickly reduced and the gas and liquid flow rates within the riser are quickly reduced. The cycle is complete and a new slug can be formed.

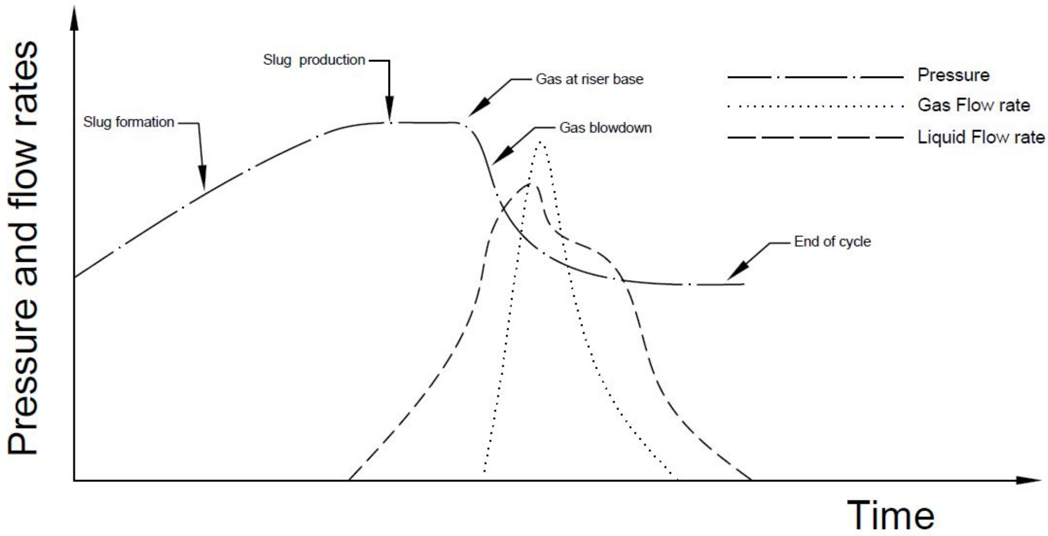


Figure 3.5: Variations of pressure and flow rates in terrain induced slug cycle

3.4.1 Slugging in the well

New technology give opportunities for more complex well trajectories to exploit the reservoir section or exploit otherwise non-economical hydrocarbon zone with optimal placement. With complex geometry, however, can slugging become a problem. In this section, some complex geometries will be discussed with focus on how the slugs are created from the geometries or reservoir properties.

Fish-hook well trajectory

Fish-hook wells have well geometry like a fish-hook, drilled downwards followed by an uphill trajectory. Low spots are created where liquid slugs can accumulate.

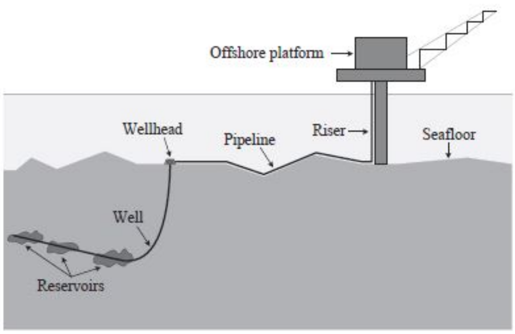


Figure 3.6: Application of fish-hook well geometry. First drilled reservoir section located deeper than the reservoirs drilled at the end (Malekzadeh, 2012)

Fish-hook wells drain hydrocarbon zones located shallower and a distance away from the reservoir first drilled through. Marginal hydrocarbon zones can be exploited to enhance the overall production from a field. Low spots are naturally generated because the well is drilled upwards and liquid accumulation can take place.

Undulations

Undulations create low spots for slugs to accumulate. When stratified flow is encountered in the downward flow direction, slug flow can be present in the upward flow direction. The same effect is seen in pipelines as the topography changes.

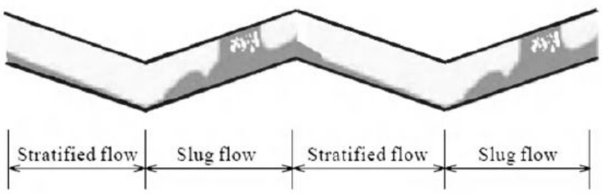


Figure 3.7: Slugging due to undulations in the well, flow from left to right (Feesa, 2003)

Undulations are also found in snake wells. These wells are characterized by drainage from several vertically stacked layers with a well trajectory that is laterally weaving to reach all the zones (Obendrauf et al., 2006). The benefit is drainage from several zones with lower costs than multilateral wells. Geosteering utilizes logging tools to navigate horizontal layers in the reservoir. Optimal placement of the well can result in undulations with low spots for slug accumulation. Horizontal wells can have undulations caused by disturbances while drilling the horizontal.

Low producing horizontal wells

Hydraulic fractured horizontal shale oil wells with extremely low permeability and productivity index are prone to slugging. Since the drainage radius is limited, the reservoir pressure will deplete rapidly below the bubble point and multiphase flow is the result. Fracturing techniques used in horizontal shale wells require liners to be of a certain size, normally 4 or 6 inches, thereby resulting in low flow velocity within the pipe and unstable flow (Norris, 2012).

Since the well path is rarely truly horizontal, it is reasonable to assume some small inclinations from the horizontal in long reservoir sections making low spots for liquid accumulation. This was studied by H. Lee Norris (Norris, 2012) by performing simulations on a typical hydraulic fractured shale well with toe-up of +0.5°, creating a low spot at the heel. The results were periodic liquid production and fluctuations as expected from terrain induced slug flow. The slugging cycle was found to be long because of low gas production rate and long horizontal section, thus the pressure build-up by the gas was slow.

3.4.2 Severe slugging

Severe slugging is the extreme version of the terrain induced slugging taking place when a pipeline-riser system goes from downward flow into a vertical riser. The low spot in a pipeline-riser system can completely block the gas passage and accumulate a severe slug that might become larger than the riser height (Malekzadeh, 2012).

Severe slugging in a pipeline-riser system is generally described by a four stage cycle of

1. Slug formation
2. Slug movement into separator
3. Blowout
4. Liquid fallback

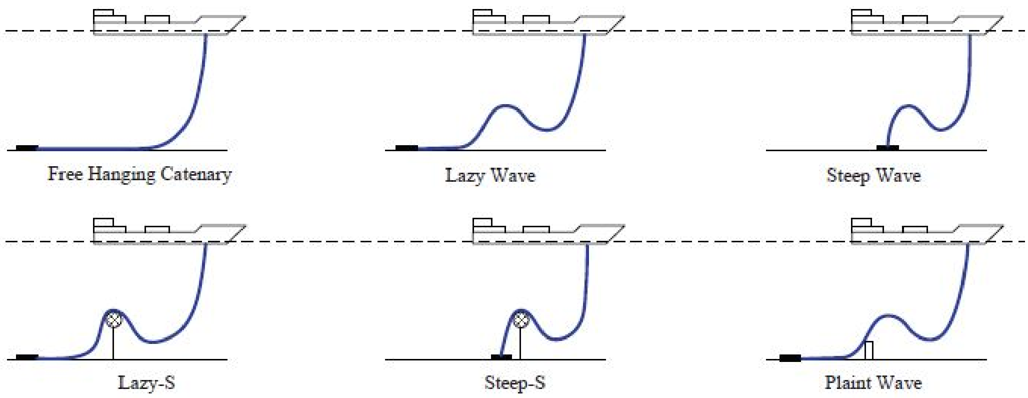


Figure 3.8: Flexible riser configurations with low spots also by the shape of the riser configurations (Jahanshahi, 2013)

The liquid level in the riser increases as both phases continue to flow into the pipeline while the gas passage is blocked resulting in pressure increase at the riser base, pushing the gas-liquid interface in the pipeline even further away from the riser base and compressing the gas in the pipeline. The liquid slug grows larger within the riser. The pressure at the riser base reaches its maximum when the liquid level reaches the riser top, and the pressure of the gas in the pipeline eventually becomes higher than the hydrostatic head of the of the liquid in the riser. Liquid starts to flow out at the top of the riser while the slug tail pushes towards the riser base. When gas enters the riser, the hydrostatic head in the riser decreases, the gas expands and the liquid column flushes out of the riser. The gas flows through the riser and the liquid slug is produced. The gas in the riser is produced rapidly, causing quick de-pressurization of the system. When all the gas is produced, the pressure reaches its minimum. The cycle is finished and new blockage can yet again take place at the riser base to start a new slug cycle (Malekzadeh et al., 2012). Figure 3.5 illustrates the typical flow rate and pressure variations in a slug cycle of this type.

3.4.3 Severe slug criteria

Throughout the years of studying slug flow in pipelines, several attempts to combine mathematical models and behaviour of slug flow have been attempted to be able to predict under which conditions severe slugging can occur.

The first condition for severe slugging to occur is effective blocking of the gas at the bottom of the riser. The flow in the pipeline must then be stratified as other flow regimes can transport the gas around the lowest point, thus not having effective blockage. Stratified flow in the pipeline is encountered when the gas and liquid flow rates are relatively low. Stratified flow in downward inclined flow moves faster than for the horizontal case and decreases the liquid height level in the pipe, requiring higher gas and liquid rates to cause transition from stratified flow to annular or intermittent (Barnea et al., 1982).

The second condition for severe slugging is that the hydrostatic pressure of the liquid in the riser must increase faster than the pressure increase of the compressed gas in the pipeline. Mathematical models and expressions for this condition have been developed by several authors and will be discussed in the following parts.

Bøe criterion for severe slugging

The Bøe criterion (Bøe, 1981) is based on force balance applied to the liquid slug blocking the entrance into the riser. The considered forces are the pressure build-up of gas as it is blocked from entering the riser, seen as compressed gas and the hydrostatic head of the liquid inside the riser. The Bøe criterion is given by the following equation (Bøe, 1981):

$$u_{SL} \geq \frac{P_p}{\rho_L g \alpha_G L} u_{SG} \tag{3.9}$$

or as

$$u_{SL} \geq \frac{\rho_{G0} R T}{\rho_L g \alpha_G L} u_{SG} \tag{3.10}$$

When the statement is valid, severe slugging can occur. Drawing from Equation 3.9 and Equation 3.10, we see that the chance of severe slugging to occur is reduced by adjusting key variables in a beneficial way;

- Decreasing superficial liquid velocity, liquid density, average void fraction and pipeline length
- Increasing superficial gas velocity, pipeline pressure and temperature

Taitel stability criterion

The stability criterion by Taitel (Taitel, 1986) is based on force balance. Severe slugging occurs because gas is compressed until it overcomes the gravitational head of the liquid in the riser resulting in a long liquid slug that is pushed in front as the gas enters the upstream riser and expands. Assume that the slug tail has just entered the riser and the riser is now filled with liquid and a small disturbance y may carry the liquid somewhat higher. The disturbance is fast enough to not affect the flow rates of liquid and gas (Taitel, 1986). This condition is illustrated in Figure 3.9.

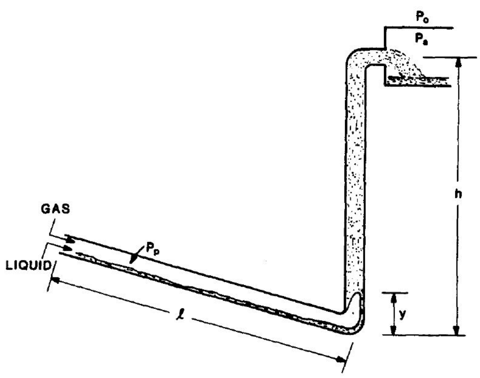


Figure 3.9: Severe slugging in a riser (Taitel, 1986)

Drawing from Figure 3.9, the net force per unit acting on the liquid film in the riser is expressed as (Taitel, 1986):

$$\Delta F = \left[\left(P_{sep} + \rho_L g h \right) \frac{\alpha_G L}{\alpha_G L + \alpha_G^{'} y} \right] - \left[P_{sep} + \rho_L g \left(h - y \right) \right] \tag{3.11}$$

If ΔF increases with y, the liquid column will be blown out of the pipe. Thus, the condition for stability is satisfied for:

$$\frac{\partial \left(\Delta F \right)}{\partial y} < 0, \qquad \text{when} \, y = 0 \tag{3.12}$$

Applying the stability condition to the net force in the riser, the criterion for stability is expressed as:

$$\frac{P_{sep}}{P_0} > \frac{(\alpha_G / \alpha_G^{'})L - h}{P_0 / \rho_L g} \tag{3.13}$$

Here, α_G is the gas holdup and $\alpha_G^{'}$ is the gas holdup in the gas cap penetrating the liquid column. Drawing from Equation 3.13, we see that the stability of severe slugging can be altered by adjusting key variables in a beneficial way;

- Decreasing the length of the pipeline and gas holdup
- Increasing separator pressure, height of the riser, liquid density and gas holdup in the gas cape penetrating the liquid column.

Pots criterion

The criterion by Pots *et al.* (Pots et al., 1987) is based on force balance where the rate of the hydrostatic pressure build-up in the riser must exceed the pressure build-up rate of the gas in the pipeline. With these conditions satisfied, the liquid fills the riser faster than gas pressure drives the flow.

$$\Pi_{ss} = \frac{zRT/M}{gL\overline{\alpha_G}} \frac{w_g}{w_L} \tag{3.14}$$

Equation 3.14 expresses the ratio between the pressure build-ups and severe slugging can occur when $\Pi_{ss} < 1$. Drawing from Equation 3.14, we see that the severe slugging can be avoided by adjusting key variables in a beneficial way;

- Decreasing pipeline length, average gas holdup in the pipeline and liquid mass flow rate

- Increasing temperature and gas mass flow rate

Jansen *et al.* model

The model proposed by Jansen *et al.* (Jansen et al., 1996) includes elimination of severe slugging to the criterion proposed by Taitel (Taitel, 1986) as back pressure increases with implementation of choking at the riser top. They assumed that the two-phase time averaged pressure drop across the choke could be approximated by (Malekzadeh, 2012):

$$\Delta P_{choke} = C u_{SL}^2 \tag{3.15}$$

The increase in pressure upstream of the choke was written as (Jansen et al., 1996):

$$P_B - \left(P_{sep} + C u_{SL}^2\right) = K y \tag{3.16}$$

The net force on the interface between the end of the liquid slug and the front of the penetrating gas phase was expressed as (Jansen et al., 1996):

$$\begin{aligned} \Delta F = & \left[\left(P_{sep} + C u_{SL}^2 + \rho_L g h\right) \frac{\alpha_G L}{\alpha_G L + \alpha_G' L}\right] \\ & - \left[P_{sep} + C u_{SL}^2 + K y + \rho_L g \left(h - y\right)\right] \end{aligned} \tag{3.17}$$

The left part of the right hand side represents expansion of gas while the right part is the resulting back pressure caused by liquid column($h - y$), separator pressure and choking. Utilizing that severe slugging is not possible when

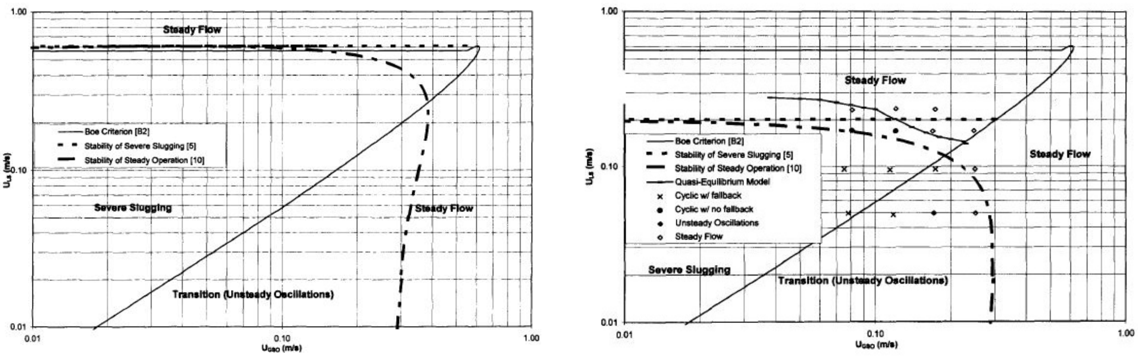
$$\frac{\partial (\Delta F)}{\partial y} < 0, \quad \text{when} \quad y = 0$$

By differentiating, the stability criterion is expressed as (Jansen et al., 1996):

$$\frac{P_{sep} + C u_{SL}^2}{P_0} \geq \frac{\frac{\alpha_G L}{\alpha_G'}\left(1 - \frac{K}{\rho_L g}\right) - h}{\frac{P_0}{\rho_L g}} \tag{3.18}$$

When there is no methods of eliminating severe slugging, the criterion overlaps the Bøe criterion for severe slugging at the top as seen in Figure 3.10a. Drawing from the stability criterion in Equation 3.18, we see that the severe slugging can be avoided by adjusting key variables in a beneficial way;

- Decreasing gas holdup in the gas cape penetrating the liquid column and liquid density
- Increasing separator pressure, choke coefficient, superficial liquid velocity, height of the riser and gas holdup



(a) No elimination **(b)** Choking, $C = 120{,}000\ \mathrm{Pas^2\,m^2}$

Figure 3.10: Choking effect on severe slugging. It is seen that choking reduce the envelope where severe slugging can occur (Jansen et al., 1996)

It was identified in the work of Yula Tang *et al.* (Tang et al., 2007) and the work of Malekzadeh and Mudde (Malekzadeh and Mudde, 2012) that severe slugging could occur in wells caused by undulations and complex well trajectories by performing dynamic wellbore simulations using OLGA. The models mentioned in this section assumes flow going from downward inclined to vertical as seen in pipeline-riser systems, but this is not the case for reservoir sections and the inclination should be included. Seen from Equation 2.10, the inclination is affecting the hydrostatic pressure drop. Further, the Bøe criterion of Equation 3.9 can be modified to include the inclination as follows (Ogazi, 2011):

$$u_{SL} \geq \frac{P_p}{\rho_L g \alpha_G \sin\beta L} u_{SG} \tag{3.19}$$

Where the inclination is given with respect to horizontal for the upward flow direction.

3.5 Mitigation techniques

Several methods are used to mitigate effects from slug flow from the pipeline-system or well. These techniques vary in the handling of the liquid slugs. The slug catcher handles the liquid volumes from the slugs on the processing facility, while other slug control measures can utilize the choking possibilities with an active controller to suppress the slugs.

3.5.1 Slug catcher

Slug catchers are designed to handle the largest expected slug volumes. Located on the processing facility, slug catchers are space demanding, which is a problem for offshore production facilities with space restrictions. Slug catchers are located between the riser outlet and the processing facility as a buffer system to handle the large volumes from liquid slugs. Proper sizing requires knowledge of the largest expected liquid slugs in the system, considered the most difficult part of slug catcher design. Other factors to consider while designing a slug catcher is capital cost, installation cost, available space, performance and transportation. The high capital cost associated with implementation of slug catchers might be economically unacceptable for some late life fields.

Slug catchers are classified in three main categories, vessel type, multi-pipe type and parking loop type. A vessel type slug catcher is suitable for offshore facilities with limited space. Moreover, with vessel type slug catcher comes simplicity in design and maintainability. The drawback is reduced buffer capabilities compared to other configurations. A multi-pipe slug catcher contains several long pieces of pipe to handle large slug volumes. However, the multi-pipe slug catcher requires much space, and is for that reason not suitable for many offshore facilities. Parking loop type slug catcher combines the features of vessel type and multi-pipe type. The particular geometry of parking loop design makes is suitable for offshore operations. The drawback of parking loop design it the dependence on strict operational conditions (Cadei et al., 2015).

3.5.2 Topside choking

Topside choking is a measure of increasing the pressure at the receiving end to obtain more stable production. The choke acts as both a pressure and flow regulator. The limitation with use of a choke as mitigation technique is reduction in production due to the topside flow restrictions through the choke, considered commercially unacceptable by several operators (Enilari et al., 2015). The choke dramatically increases the pressure drop at high flow rates. At low flow rates, however, the influence of the choke is significantly reduced.

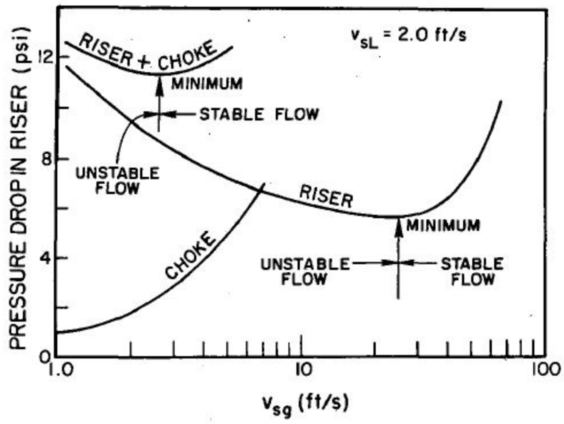


Figure 3.11: Pressure drop in a riser with choke as mitigation technique for severe slugging with $u_{SL} = 2.0$ft/s. It is seen that Riser + Choke reduces the superficial gas velocity needed to obtain stable flow, opposed to not having a choke (Schmidt et al., 1985)

Assume a flow rate in the region of stable flow. An increase in gas flow rate results in increased pressure drop in the riser, which in turn requires higher pipeline pressure. Higher pipeline pressure can only be achieved by reducing the flow rate out of the pipeline since the inflow is assumed constant (Schmidt et al., 1985). Studying the statement above with the Bøe criterion from Equation 3.9, we see that increasing pipeline pressure increases the right hand side of the Bøe criterion, thus reducing the likelihood of severe slugging in the riser.

3.5.3 Gas injection at riser base

Gas injection at the riser base works like gas lift works in a well by reducing the hydrostatic head in the riser. Other effects from gas injection are reduced pipeline pressure and slug cycle time resulting in more continuous liquid flow. However, for gas injection to be effective, large amounts of injected gas are required. The system is not completely stabilized if the gas injection rate is not sufficiently high. The flow within the riser must approach annular flow conditions to achieve stable flow (Hill, 1990). The gas to oil ratio is increased and severe slugging can be reduced or avoided.

3.5.4 Combination of topside choking and gas injection

The synergy effect of using a combination of topside choking and gas injection at the riser base is drastically reduced gas injection rate for optimum operating conditions as well as requiring less degree of choking. The choking stabilizes the flow by increasing the liquid velocity while the gas injection stabilizes the flow by increasing the gas velocity (Jansen et al., 1994). Cost savings can be achieved because less available gas are required.

3.5.5 Controllers

Dynamic measurements from the well or production system is fed to controller systems that stabilize the flow and suppress the slugs. Correct field data and models are crucial for the controllers to function as intended to ensure optimized production. Main drawback with controllers is the lack of robustness as the system becomes unstable after some time when operating conditions change. The operators, instead of tuning the controller again, often switch over to manual choking when the controller becomes unstable (Jahanshahi, 2013). The control system is dependent on the operating conditions of each field and must be tuned in order operate correctly for a specific field and operating conditions.

PI-controller and PID-controller uses the feedback from monitoring to adjust the flow conditions to obtain stable flow. A PID-controller has the advantage of reducing the oscillations compared to PI-control and process response time can be reduced. On the other hand, tuning is harder than for PI-control as there are more parameters involved.

A Shell development (Yaw et al., 2014) for handling slugs in pipeline-riser systems is the Smart Choke based on a single control valve installed between the riser top and first stage separator. The Smart Choke is compact and cost efficient compared to other measures to mitigate slug flow. Pressure readings are used as information about incoming flow which then are used in the control algorithm for the Smart Choke. The control mechanism aims to maintain constant volumetric flow rate at the outlet via a fast acting flow controller.

3.5.6 Subsea processing

With subsea processing comes the possibility of separation of oil, gas and water at the seafloor. By separating oil, gas and water at the seabed comes possibility of utilizing several flowlines for the transportation to the production facility, thereby avoiding the possibility of slug generation in the pipeline-riser system.

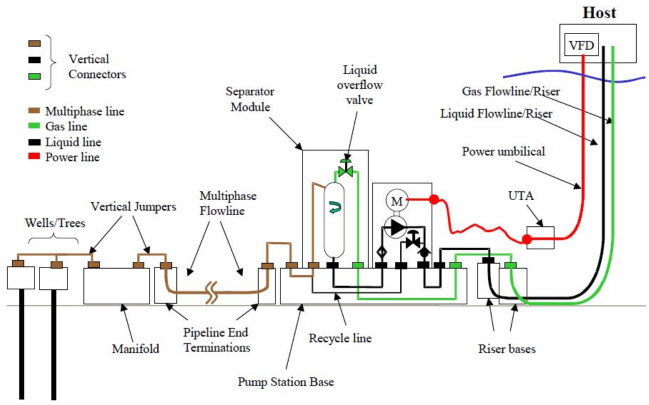


Figure 3.12: Subsea processing with separation of gas and liquid on the seafloor before transportation to processing facility utilizing two flowlines (Haheim et al., 2009)

Although pipeline-riser slugging can be avoided by utilizing two flowlines, slugging from the wells are not avoided. Another benefit from subsea processing is the possibility of boosting to increase the pressure in the pipeline, making it possible to produce from low-pressure reservoirs. The increased pipeline pressure increases the right hand side of the Bøe criterion from Equation 3.9, thus reducing the possibility of severe slugging in the pipeline-riser system. Subsea processing can also increase the recovery rate from a field.

3.6 Case reviews

In this section two cases from the North Sea will be studied focusing on the experiences. The first case was a subsea tieback at Yme with topography resulting in terrain induced slugging. The second case experienced terrain induced slugging originating from three places, the S-shaped riser, riser base and from the well.

3.6.1 Yme, marginal field with subsea tieback

The paper by Øverland and Ramstad (Øverland and Ramstad, 2001) is used for the review in this section. Yme was a marginal oil field in the southern part of the North Sea with low GOR and slightly over pressurised reservoir requiring artificial lift in early stages of production. The subsea tieback, Yme B, located approximately 12 km from the processing facility, experienced heavy slugging immediately after gas lift was utilized as artificial lift. The topography caused terrain induced slugging in the pipeline 8-9km from the subsea template as seen in Figure 3.13.

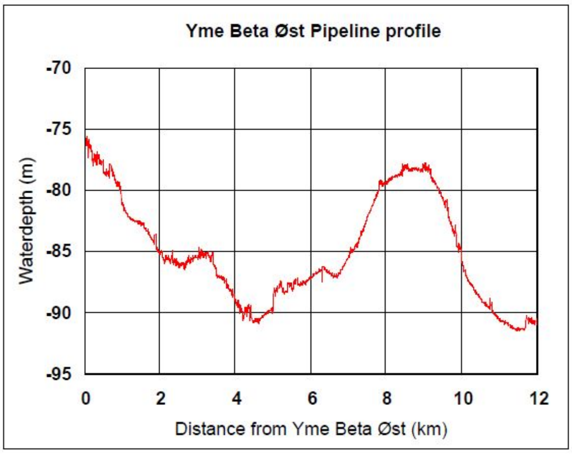
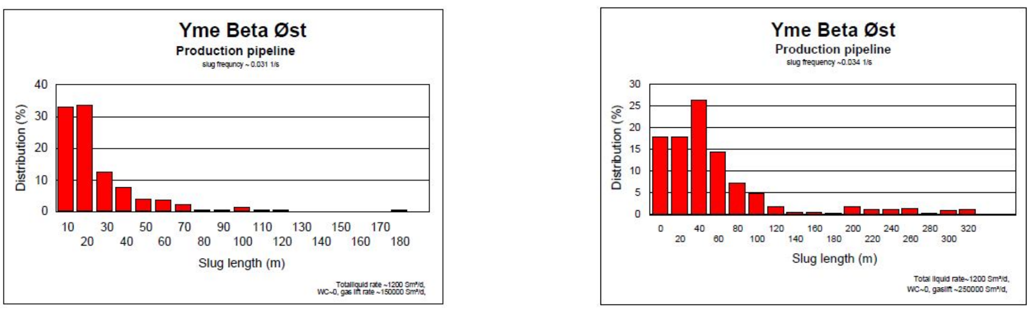


Figure 3.13: Yme B pipeline topography causing terrain induced slugging 8-9 km from the Yme B subsea template (Øverland and Ramstad, 2001)

Topside choking was implemented to reduce the heavy slugging at the expense of production rates. The slug catcher at the processing facility was not designed to handle heavy slugging and did not reduce the pressure fluctuations and production rate peaks sufficiently to avoid shut downs. Production losses were significant as all the wells were affected in a shut down scenario. Upgrade of the slug catcher was considered, but was not found economically acceptable due to the production losses during installation period and the high cost. This aspect shows the importance of designing the slug catcher correctly and how it must be able to handle the largest anticipated slugs in the production system. The instabilities increased with increasing gas lift rate as seen in Figure 3.14.



(a) 150 kSm^3/d **(b)** 250 kSm^3/d

Figure 3.14: Effect of gas lift rate on slug length from Yme Beta Øst. (a) Gas lift rate of 150 kSm^3/d, lower frequency and slug length. (b) Gas lift rate of 250 kSm^3/d, higher frequency and slug length (Øverland and Ramstad, 2001)

3.6.2 Åsgard Q, subsea tieback

Skofteland *et al.* (Skofteland et al., 2007) published a paper about a control system implemented at Åsgard Q to suppress the liquid slugs. Åsgard Q, a subsea tieback located 13 km away from the production ship Åsgard A, experienced heavy slugging shortly after production had started. The slugs did not cause major problems at the processing end, but during low liquid flow periods the temperature in the pipelines were reduces significantly. The main concern was hydrate formation as the temperature decreased.

Table 3.1: Pressure and variations in the production system at Åsgard

Location	Pressure	Variaton
In the well	220-260 bar	40 bar
Subsea choke	85-98 bar	13 bar
Topside choke	58-74 bar	16 bar

Three possibilities of terrain induced slugging was identified, from the S-shaped riser, the riser base and the well. It was identified that the heavy slugging originated from the well with long slugging cycle and high pressure variations.

Table 3.2: Terrain induced slugging from Åsgard Q

Location	Slug cycle time	Pressure variation
S-shaped riser	5 minutes	1 bar
Riser base	30 minutes	5-10 bar
In the well	6-7 hours	20-40 bar

Decision was made that active controllers should be utilized to stabilize the flow using feedback from downhole pressure measurements. The topside choke was controlled by the pressure measurements in the well. The flow was effectively stabilized, but the topside choke only had the possibility of controlling one well. Use of the subsea choke instead of the topside choke was proposed and was found to stabilize the flow oscillations from the well effectively. The control system for the subsea choke used pressure reading downhole, just as for the topside choke.

Chapter 4

Experimental Work

4.1 Introduction

Experiments have been conducted in a 40 mm inner diameter pipe with air-water flow. The experiments have been conducted to evaluate the potential use of a rotating device with propeller and mixer to alter the flow behaviour in the pipe in a significant and beneficial way. Three geometrical configurations have been made to study the impacts of placing the turbine in horizontal, vertical and inclined sections.

4.2 Experimental setup

Three flow loop configurations have been studied. The first flow loop contained two bend sections to simulate undulations found in well sections. The second flow loop had a longer bend section with flow going directly to the vertical at the lowest point to simulate a pipeline-riser system. The third flow loop had two horizontal sections in order to study hydrodynamic slugging.

4.2.1 Configuration 1

This configuration was made to simulate the geometry of undulations to study terrain induced slugging. The problem was short distance of the bend sections and dimensions of the flow loop, not allowing pressure build-up and continuously transported gas. Slug formation happened in the loop, but the characteristics were small slug lengths with low frequency. Chaotic behaviour was observed at the base of each bend section.

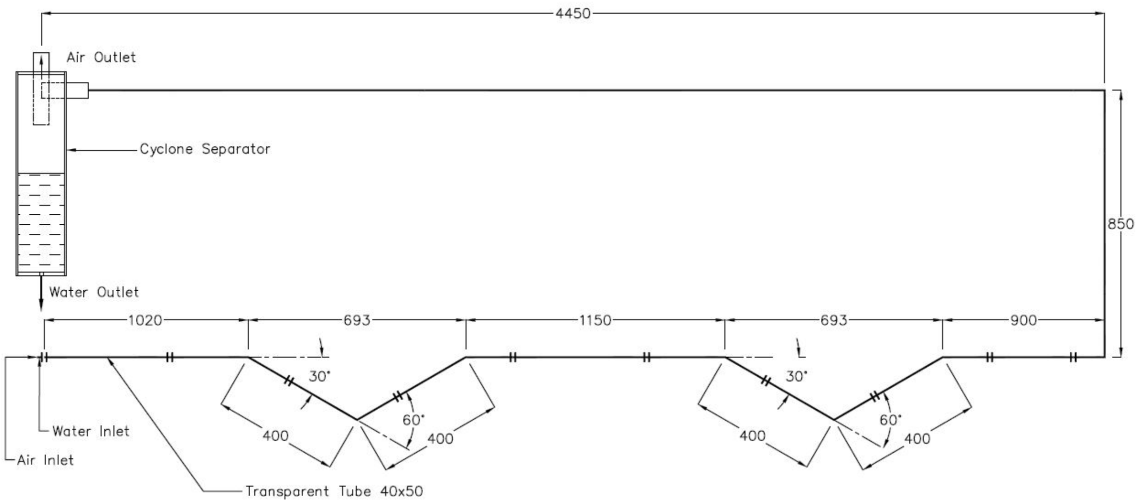


Figure 4.1: Schematic of flow loop 1 consisting of two bend sections to simulate the geometry of undulations in a well section or pipeline topography, lengths given in mm.

Figure 4.2: Picture of flow loop 1

Using the modified Bøe criterion of Equation 3.19 and assuming standard conditions, air-water flow, and $u_{SL} = u_{SG}$, it was found that the minimum length for terrain induced slugging to take place was approximately 25 m for this geometrical configuration.

4.2.2 Configuration 2

Configuration 2 was made because of drawbacks with configuration 1 as it did not create large slugs that the turbine could break down, but instead continuously transported gas as small bubbles. The same problems took place in configuration 2 as pressure build-ups were not possible and gas was continuously transported along the flow. By studying the loop with the Bøe criterion of Equation 3.9, it was seen that the bend section required at least 12-13 m length to accumulate terrain induced liquid slugs at the base.

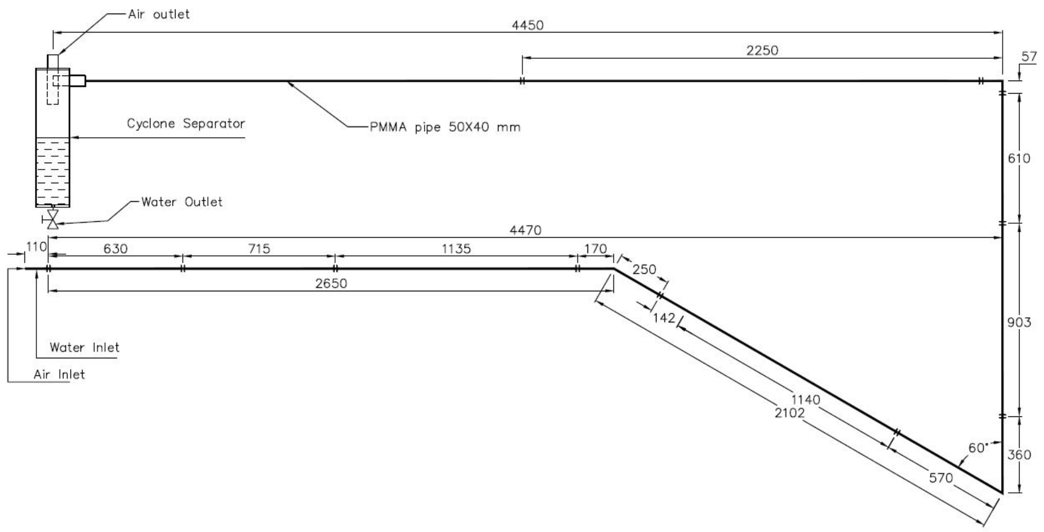


Figure 4.3: Schematic of flow loop 2 consisting of a longer bend section, lengths given in mm.

Figure 4.4: Picture of flow loop 2

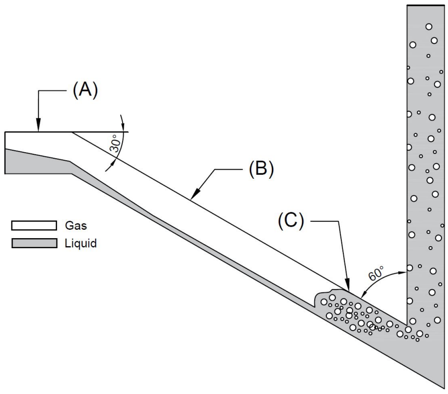
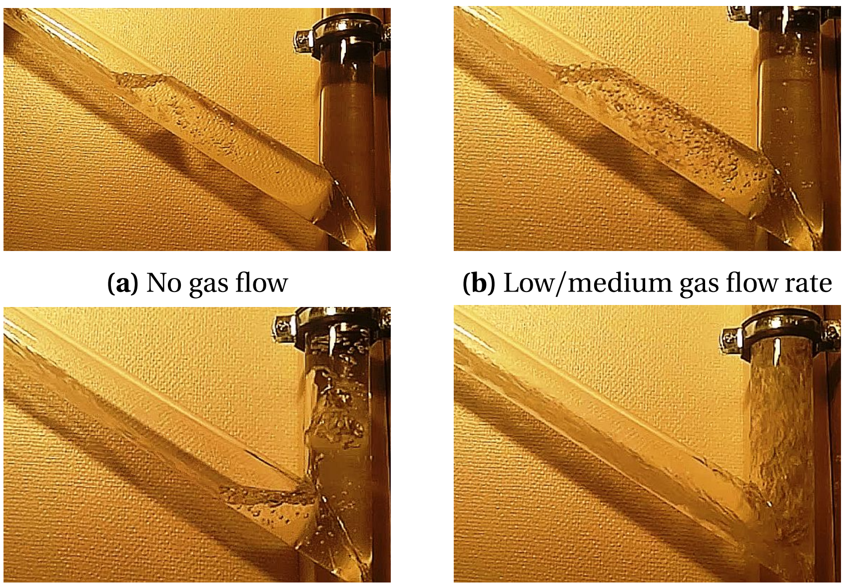


Figure 4.5: Illustration of bend section flow in configuration 2, positions (A), (B) and (C) explained below

- **(A)** Flow in the horizontal section. Liquid phase velocity is here lower than at (B), but the liquid is accelerated close to the bend section due to gravity.
- **(B)** Liquid flow in inclined section is further accelerated by the gravitational pull, increasing the liquid phase velocity.
- **(C)** Chaotic zone where small gas bubbles are dispersed in the water zone. The gas is dragged with the flow because of the interaction between the phases at the interface and some of the gas is dragged with the flow to the vertical section, thereby continuously transporting some gas.



(a) No gas flow

(b) Low/medium gas flow rate

(c) High gas flow rate

(d) Very high gas flow rate

Figure 4.6: Flow in bend section of configuration 2

From Figure 4.5 and Figure 4.6, it was seen that gas was transported efficiently with the liquid flow, thus not blocking the free gas passage and no terrain induced slugging took place.

4.2.3 Configuration 3

Configuration 3 was made to study hydrodynamic slugging as described in Section 3.2. Hydrodynamic slugs quickly occurred close to the inlet and grew in size along the flow. The nature of hydrodynamic slugs differs a lot from the nature of the terrain induced slugging

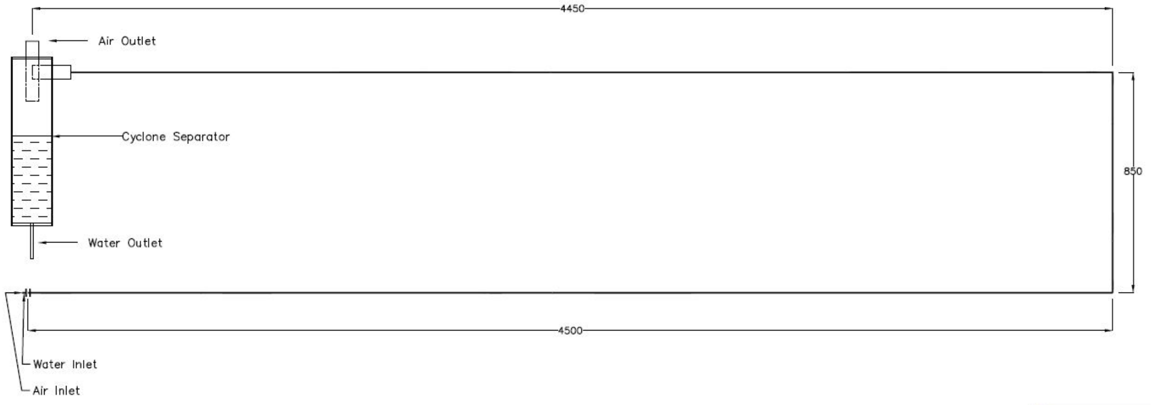


Figure 4.7: Schematic of flow loop 3 consisting of horizontal section to study the effect of hydrodynamic slugging, lengths given in mm.

Figure 4.8: Picture of flow loop 3

4.3 Equipment

4.3.1 Turbine

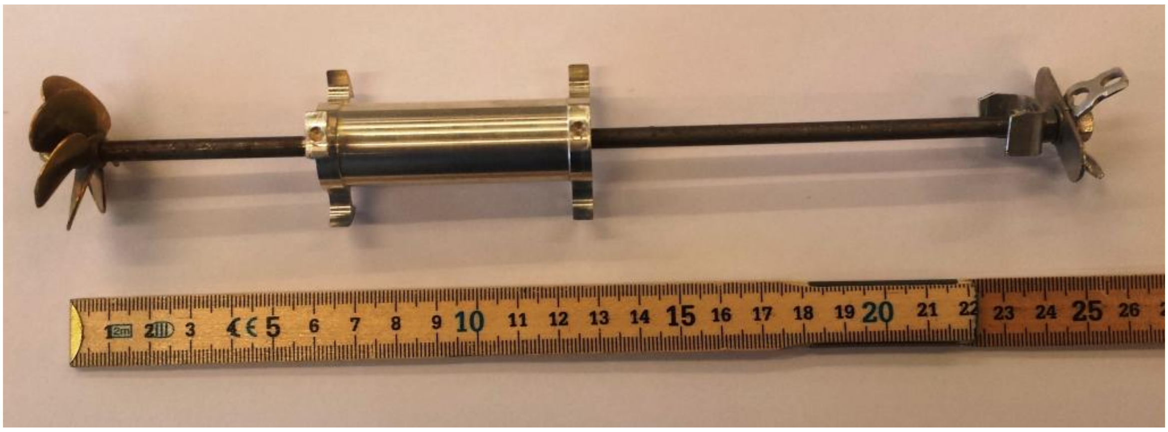


Figure 4.9: Picture of the turbine used in the experiments

Propeller

Two propellers were considered for the experiments consisting of three and six blades, respectively. The six bladed propeller was found to function best in the experiments for this thesis because the impulse from the water was the driving mechanism that resulted in rotation. The function of the propeller was to rotate the turbine and it was seen through testing that the water had the biggest impact.

(a) Three bladed propeller

(b) Six bladed propeller

Figure 4.10: Propeller designs used in the experiments (Raboesch®, 2016)

Bearings

Originally the ball bearings caused high friction because they were fitted with grease. The turbine was taken apart, the grease were removed and the bearings were sprayed with Teflon to reduce the friction. Before the modification to the bearings, the turbine was not rotating in horizontal flow flow direction. The bearings were the connection part between the housing and the rotating shaft and used to reduce friction compared to having the shaft rubbing against the housing.

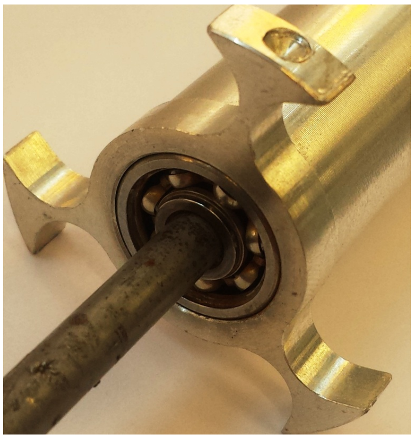


Figure 4.11: Bearings

Mixing part

The mixing part of the turbine was used to disperse the gas in the slug flow and affect the gas-liquid interface by mixing the phases together. The mixing part was essentially the part that was meant to mechanically break down the slugs.

Figure 4.12: Mixing part of the turbine

Housing

The housing part was the connection point between the turbine and the pipes used to lock the turbine in place with a screw. It was found that the surface area occupied by the housing was approximately 470 mm^2. Further, the reduction of flow area over the turbine because of the housing was approximately 37.5 %.

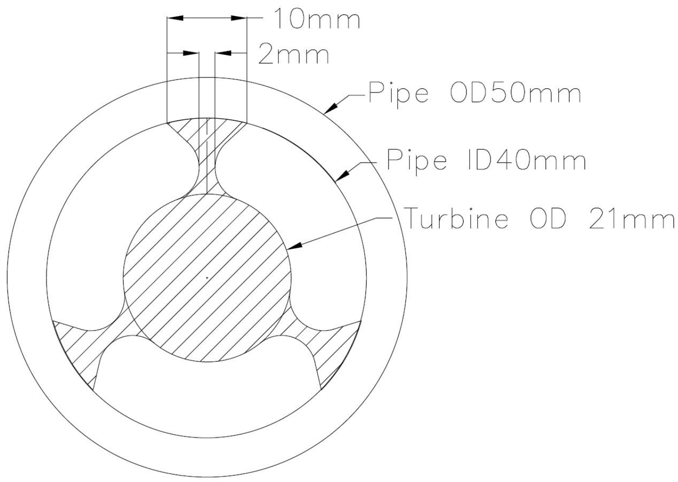


Figure 4.13: Illustration of surface area occupied by the turbine in the flow systems

4.3.2 Pipes

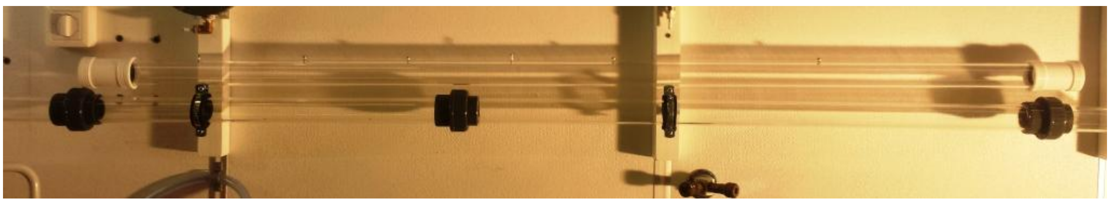


Figure 4.14: Pipes used in the experiments

Transparent acrylic glass pipes Ø50x40 mm were used in the experiments. In Figure 4.14 two different connections are used. The pipe at the bottom had the connections used in experiment 1 to 5, but for experiment 6 it was decided to use white union muffs to connect each pipe because the other connections seemed to affect the flow behaviour with small local disturbances. Bend sections and the original connections were glued together using acrifix.

(a) PVC union muff with O-ring to seal

(b) White PVC double muff

Figure 4.15: Pipe connections used in the experiments. (**a**) Connection in experiment 1-5 (**b**) Connection in experiment 6 (Dahl, 2015*a*,*b*)

4.4 Test conditions

4.4.1 Liquid flow rate and superficial velocity

The maximum liquid flow rate was found by measuring the time of filling a bucket of 20 litres with the water taps fully opened. By conducting several measurements, it was found that the average time to fill the bucket was 79.5 s. It followed that the average maximum liquid flow rate was:

$$Q_L = \frac{20\,\mathrm{l}}{79.5\,\mathrm{s}} = 0.25\,\mathrm{l\,s^{-1}} \tag{4.1}$$

Further, the superficial liquid velocity was calculated by using Equation 2.2 as follows:

$$u_{SL} = \frac{Q_L}{A} = \frac{0.25\cdot 10^{-3}\,\mathrm{m^3\,s^{-1}}}{\frac{\pi}{4}(0.04\,\mathrm{m})^2} = 0.20\,\mathrm{m\,s^{-1}} \tag{4.2}$$

The low superficial liquid velocity limited the range of the experimental study substantially. However, it is important to identify that slug flow was expected in flow loop 3 with horizontal flow according to the flow regime maps from Figure 2.6. The liquid flow rate was kept constant at the maximum rate in the experiments.

4.4.2 Gas flow rate

The gas flow rate was regulated by using two ball valves, one to regulate the flow, the other for on/off-control. Between tests, the on/off-control valve was used so the other valve could be kept at a fixed value. The gas pressure at the outlet from the laboratory was varying between 7 and 8 bar between each day. Since the pressure was varying, each individual experiment was carried out within a short time span. The gas flow rate did not cause any restrictions for the conducted experiments. In the experiments, the gas flow rate was high as shown in Figure 4.16.

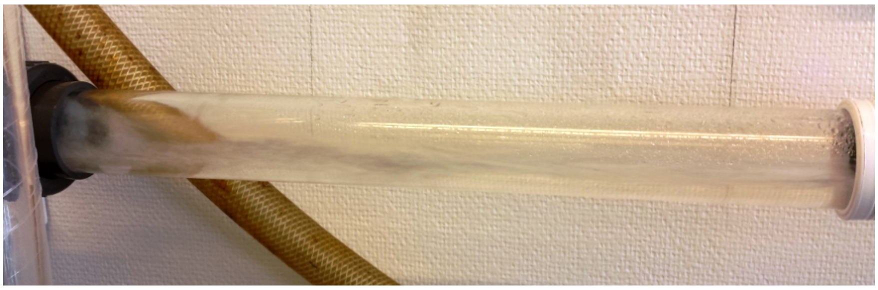


Figure 4.16: High gas flow rate close to the inlet as used in the conducted experiments.

4.4.3 Flow regimes

Slug flow was encountered in all three configurations, but not caused by the terrain or geometry. It was seen in flow loop 1 that small slugs were created after the last bend section as gas was transported along the flow efficiently. In flow loop 2 slug flow was encountered in the vertical section over a narrow range of parameters and the flow quickly transitioned to churn flow when the gas rate was increased. In flow loop 3 hydrodynamic slugs were created close to inlet because of instability at the gas-liquid interface.

4.5 Testing procedure

Following test procedure was used to establish slug flow in the flow loops

- Configuration to be studied was set up, all sections could easily be changed.
- The water rate was set to the maximum rate of $Q_L = 0.25\,\mathrm{l\,s^{-1}}$.
- The gas rate was set to desired value to get slug flow in configured loop. Between each test, a valve was used as on/off-controller for the system to keep the gas rate constant.
- Camera was used to capture effects from the turbine and a yardstick was attached to the pipe to measure slug lengths (l_s).
- A series of tests were conducted at once to ensure same conditions for each experiment.

Chapter 5

Results

Several experiments were conducted to test the placement of the turbine and the effect on the flow behaviour.

- Experiment 1: Horizontal flow loop of configuration 3, turbine 120 cm from inlet
- Experiment 2: Horizontal flow loop of configuration 3, turbine 195 cm from inlet
- Experiment 3: Modified horizontal flow loop with one bend section and turbine in downward inclined section
- Experiment 4: Flow configuration 1 with 2 bends, turbine in each bend
- Experiment 5: Horizontal flow loop of configuration 3, turbine in the vertical section
- Experiment 6: Horizontal flow loop of configuration 3, placement of turbine 80-200 cm from inlet

5.1 Experiment 1

The horizontal flow loop configuration was used with the turbine placed 120 cm from the inlet. First test was conducted with the turbine 120 cm from the inlet and captured on film. Further, the turbine was taken out and results captured on film. Flow conditions were $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and high gas rate. Test interval was 70 to 170 cm before the vertical section. The distance from the inlet to the turbine is measured from the inlet to the starting point of the housing.

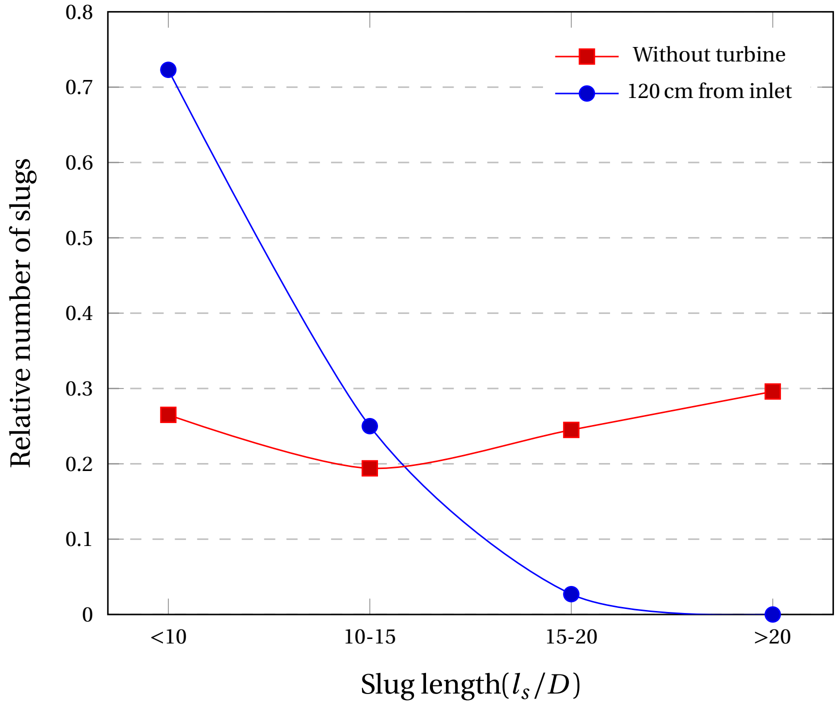


Figure 5.1: Size distributions of liquid slugs from placing the turbine 120 cm from inlet in horizontal direction

The results indicated an impact from placing the turbine close to the inlet in the horizontal flow direction. The frequency increased from 0.408 Hz to 0.617 Hz, but the average slug length was reduced. Even though the total frequency increased, the frequency for $l_s > 10$ D decreased from 0.300 Hz to 0.171 Hz with the turbine. Slugs with size $l_s = 15-20$ D decreased by 83 %. It was also seen that slugs with $l_s > 20$ D with turbine 120 cm from the inlet was 0 while there was 29 slugs without the turbine in the flow system.

5.2 Experiment 2

The horizontal flow loop configuration was used with the turbine placed 195 cm from the inlet. First test was conducted without the turbine in the system. Further the turbine was placed in the flow loop and second test was conducted. Flow conditions were $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and high gas rate. Test interval was 70 to 170 cm before the vertical section.

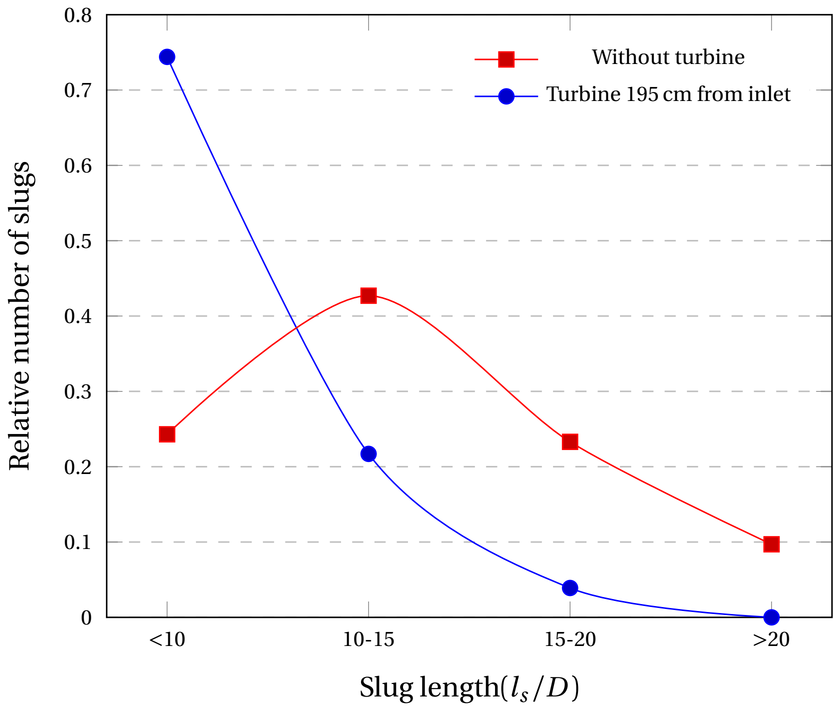


Figure 5.2: Size distributions of liquid slugs from placing the turbine 195 cm from inlet in horizontal direction

The results indicated an impact when the turbine was placed 195 cm from the inlet in horizontal flow direction. The results without the turbine in the loop was different from the curve from experiment 1. The frequency increased from 0.429 Hz to 0.538 Hz. Like in experiment 1, the frequency for $l_s > 10$ D decreased in experiment 2 as well, from 0.325 Hz to 0.138 Hz with the turbine 195 cm from the inlet. Slugs with size of $l_s = 15-20$ D decreased by 79 %. It was seen that slugs with $l_s > 20$ D with turbine 195 cm from the inlet was 0 while 10 were observed without the turbine.

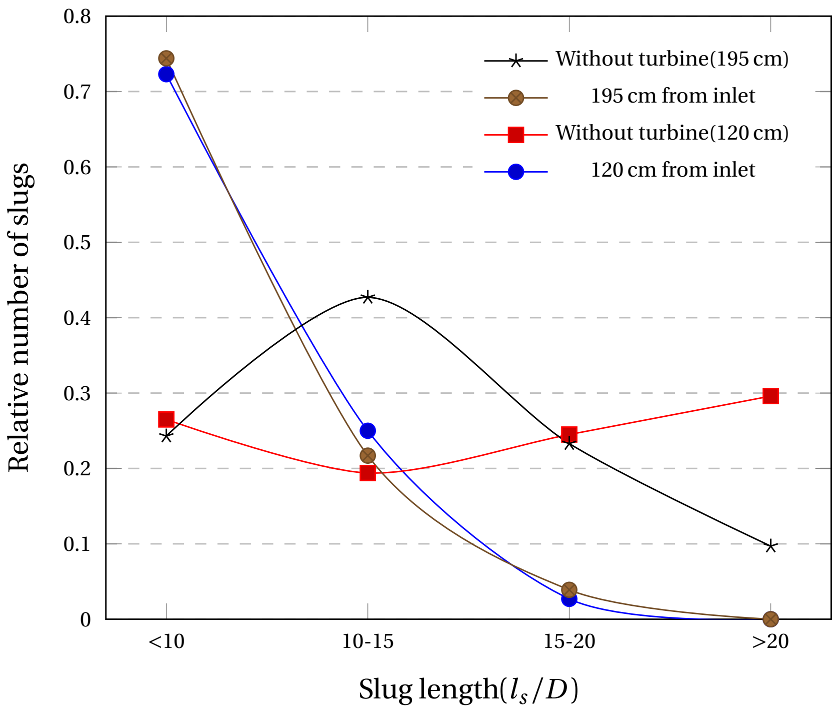


Figure 5.3: Comparison between 120 cm from inlet and 195 cm from inlet

The comparison between the turbine 120 cm and 195 cm from the inlet illustrated that the slug sizing with the turbine in the system had similar trends, but this was not the case without the turbine in the flow loops. The gas rate was not kept constant because the tests were conducted at two separate days which might have led to some differences between the two plots, but the largest impact was believed to be caused by changing the pipe positioning to allow for the turbine to placed 195 cm from the inlet. The pipe connections were changed for experiment 6 as described in Section 4.3.2.

5.3 Experiment 3

The horizontal flow loop was modified to have one bend section in the middle. The turbine was placed in the inclined section in the downward flow direction with the mixing part close to the base point of the bend section. The first test was conducted with the turbine and the second test was conducted without. Flow conditions were $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and high gas rate. The test interval was closer to the vertical section because of short distance from the bend section to the original test interval. The results indicated no significant impacts from placing the turbine in flow loop with one bend section. No slugs of size $l_s > 20$ D were observed for both tests.

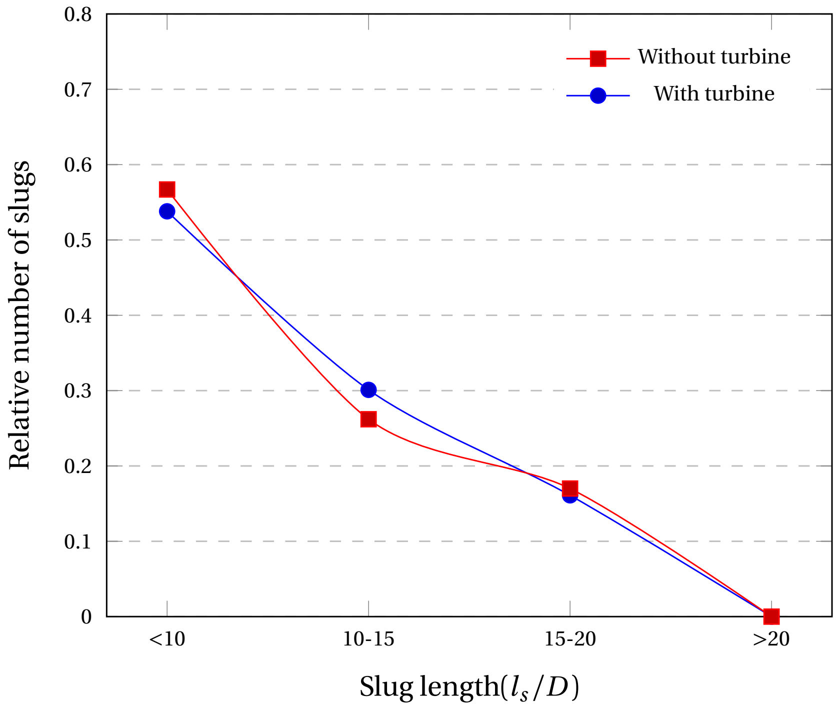


Figure 5.4: Slug lengths from placing turbine in bend section in modified flow loop containing one bend

5.4 Experiment 4

The configuration of flow loop 1 was used with two turbines, one in each bend section. The first test was conducted without the turbines and the second test was conducted with. Flow conditions were $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and high gas rate. The test interval for this experiment was at the top horizontal section because of short length from second bend section to vertical section, 90 to 190 cm from the vertical section. The results indicated no significant impacts from placing two turbines in flow loop with two bend sections. No slugs of size $l_s > 20$ D were observed for both tests. Compared to Experiment 3, which had one bend section, the frequency was drastically reduced with two bend sections, probably caused by the gas accumulating at the top between the bend sections.

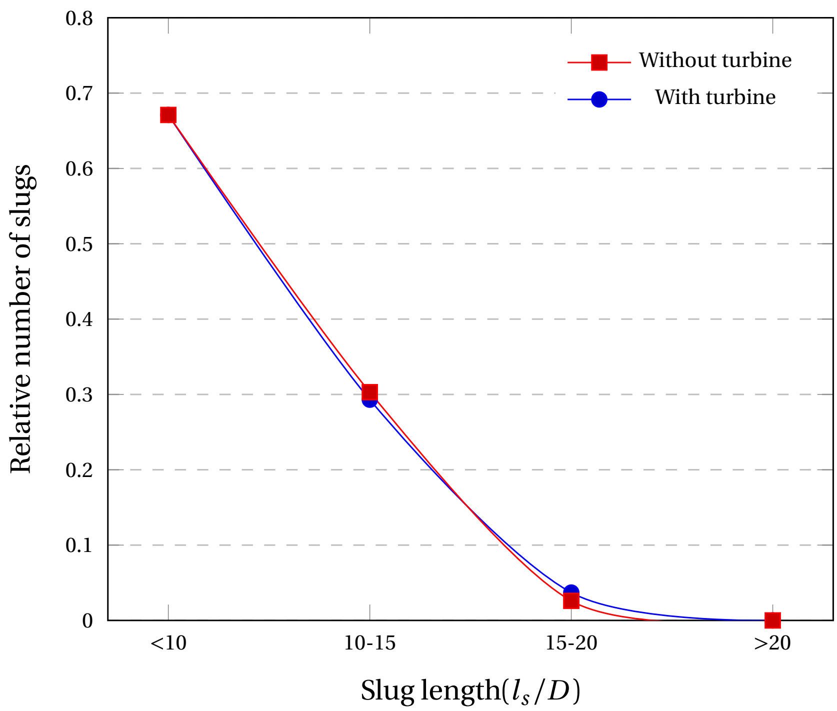
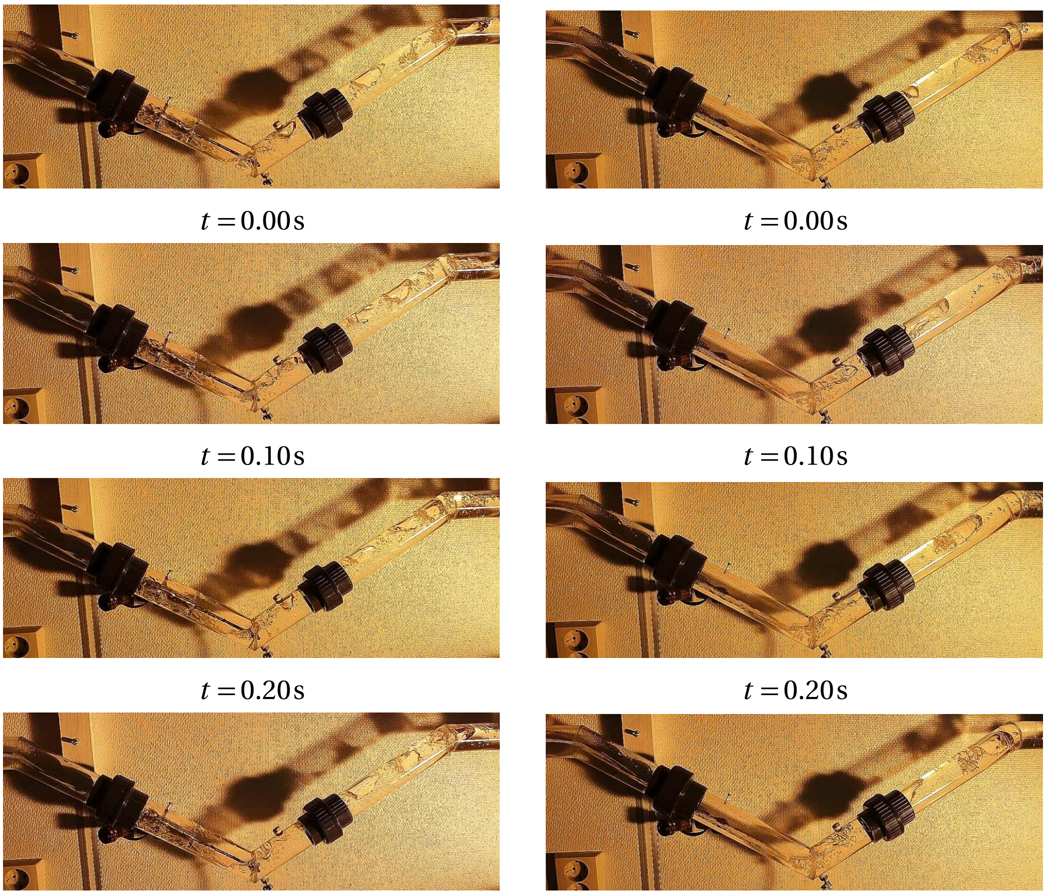


Figure 5.5: Slug lengths from placing turbines in bend sections of flow loop 1

Figure 5.6 illustrates how the gas was efficiently transported with the flow in the case of flow in bend section. No difference between the two cases was seen supporting the results from experiment 3 and 4.



$t = 0.00$ s | $t = 0.00$ s

$t = 0.10$ s | $t = 0.10$ s

$t = 0.20$ s | $t = 0.20$ s

$t = 0.30$ s | $t = 0.30$ s

Figure 5.6: Comparison with and without turbine in bend section. Left: with turbine, right: without turbine

5.5 Experiment 5

The horizontal flow loop was used in this experiment. The turbine was placed in the vertical section with the propeller at the top and mixing part at the bottom. The first test was conducted without the turbine and the second test was conducted with. Flow conditions were $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and high gas rate. The test interval was at the top horizontal section, 90 to 190 cm from the vertical section. The results indicated minor impacts from placing the turbine in the vertical section of the horizontal flow loop. The frequency decreased from 0.321 Hz to 0.313 Hz, considered insignificant. Frequency for $l_s > 10$ D decreased from 0.300 Hz to 0.171 Hz. Slugs with size of $l_s = 15-20$ D decreased by 29 % and slugs with size of $l_s > 20$ D decreased by 19 %.

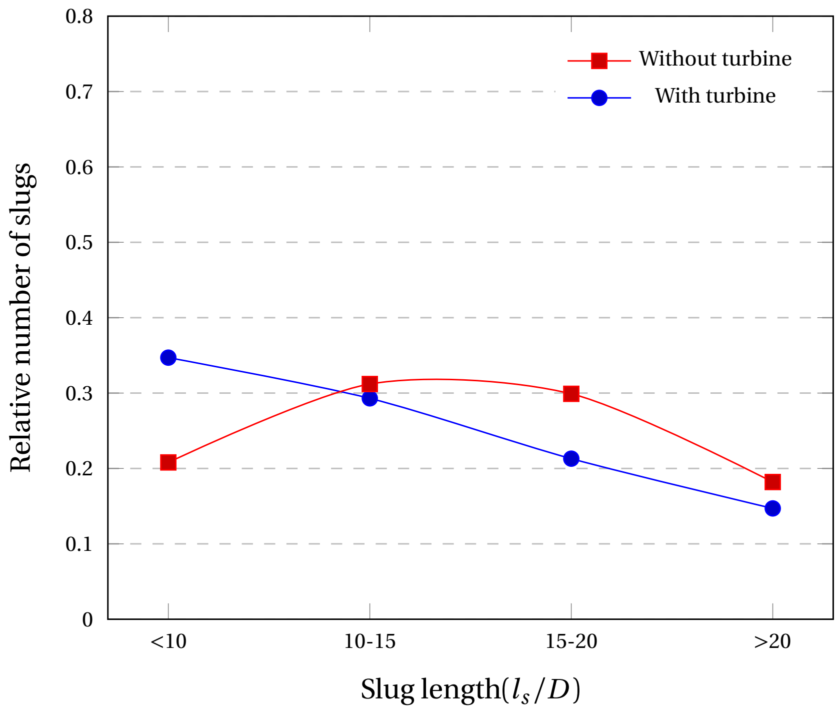


Figure 5.7: Slug lengths from placing turbine in vertical section of the horizontal flow loop

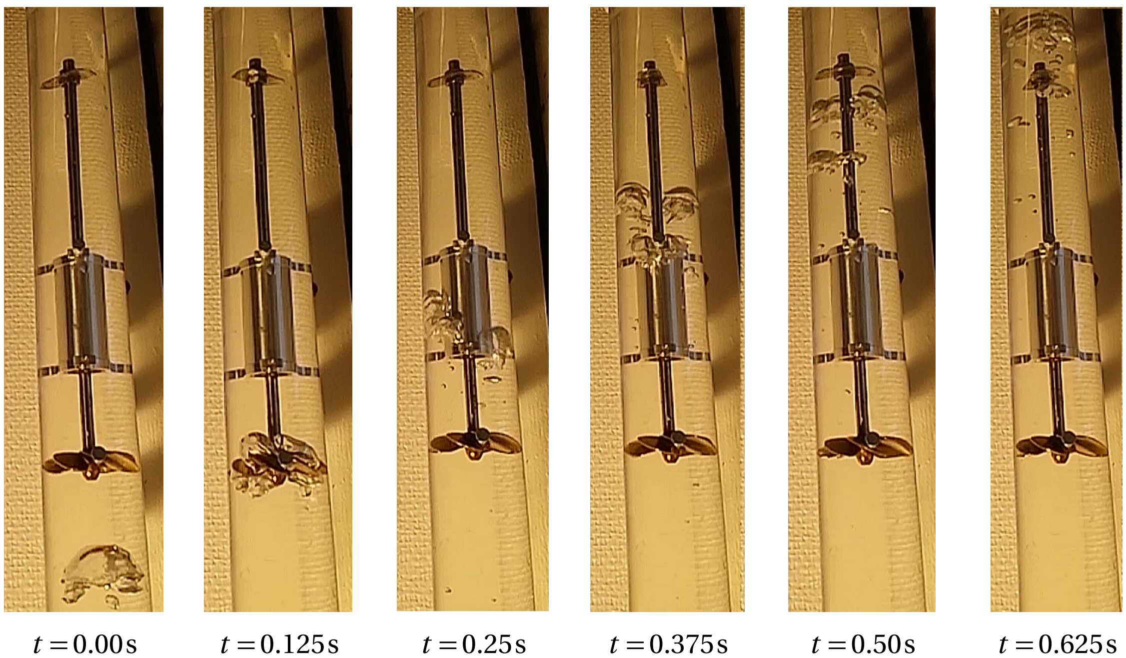


Figure 5.8: Breakdown of small gas bubble in vertical upward flow direction, $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and low gas rate

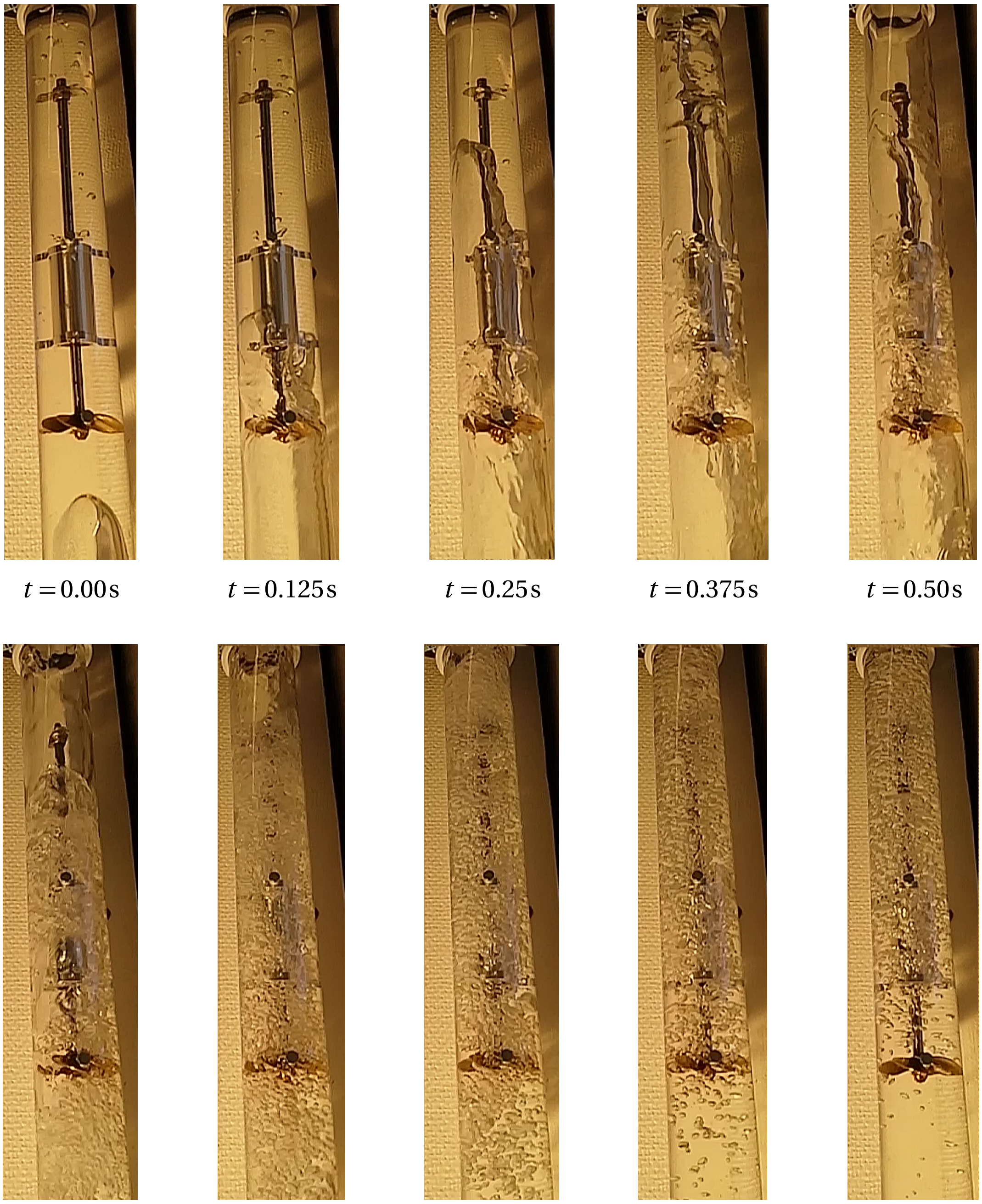


Figure 5.9: Slug flow over turbine in vertical flow direction, $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and medium high gas rate

It was seen from Figure 5.8 that the turbine was able to break down small gas bubbles in the vertical flow direction, but when Taylor bubbles ascended over the turbine, it was not able to break the gas bubble, as shown in Figure 5.9. The turbine stopped as the Taylor bubbles flowed across the turbine.

5.6 Experiment 6

The horizontal flow loop from previous experiments were modified slightly by changing the connections to remove small disturbances caused by the original connections. First test was conducted without turbine, followed by tests with the turbine 80, 100, 120, 140, 160 and 200 cm from the inlet. The last test was conducted without the turbine in the flow loop. Flow conditions were $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and high gas rate. Test interval was 70 to 170 cm before the vertical section.

It was seen from Figure 5.10 some differences for the values $l_s = 10-15D$ and $l_s = 15-20D$ for the two cases without the turbine. The difference was small enough to be caused by the randomness in slug lengths for hydrodynamic slugs. The plot indicated that large slugs were occurring without the turbine in the flow system.

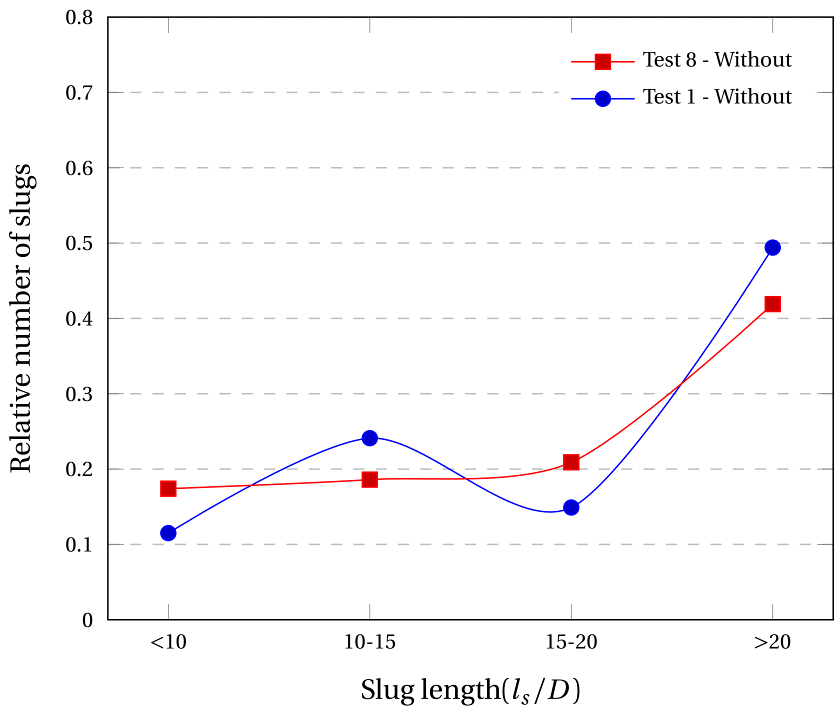


Figure 5.10: Slug lengths without the turbine in experiment 6

Further it was seen from Figure 5.11 impacts of placing the turbine in various positions from the inlet. The plot indicated that the amount of larger slugs decreased as the turbine was placed closer to the test interval. This could be caused by the distance from the turbine to the test interval being shorter and not enough distance for the slugs to grow. It was identified, however, that all the trends with the turbine had reduced relative number of large slugs, while without the turbine the relative number of slugs were highest for slugs with size $l_s > 20$ D.

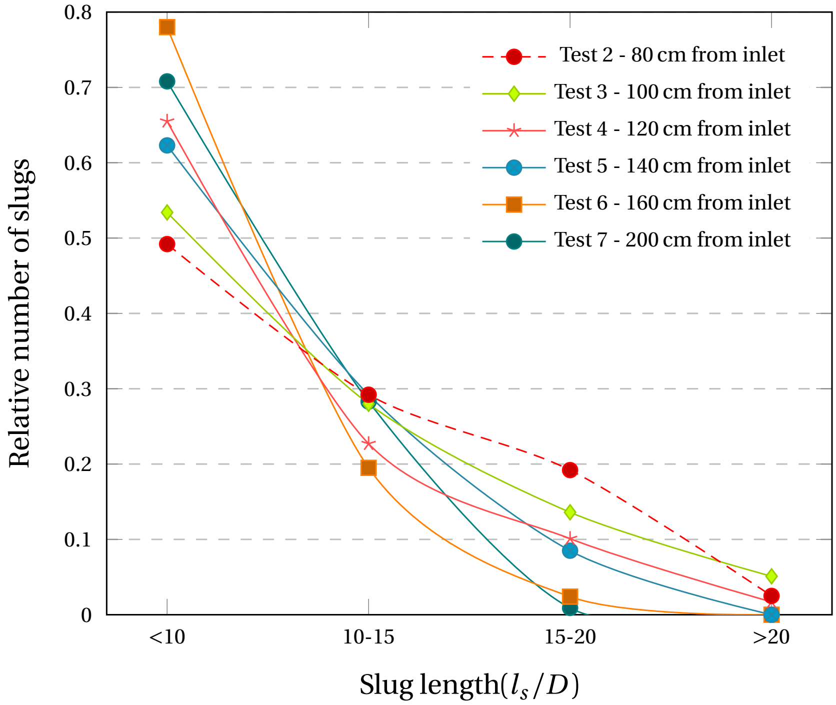


Figure 5.11: Impact of turbine on slug sizes with the turbine at various positions from the inlet

It was seen by the comparisons in Figure 5.12 and Figure 5.13 that the turbine reduced the slug length effectively over short distances. The results revealed that the number of slugs with $l_s > 20$ D with the turbine in the system were 11 over six tests, while 79 slugs with $l_s > 20$ D were recorded in the two tests without the turbine in the system. The average overall frequency increased with the turbine from 0.360 Hz to 0.481 Hz, while the average frequency when excluding the slugs with size $l_s < 10$ D decreased from 0.308 Hz to 0.177 Hz with the turbine. Slugs with size of $l_s = 15-20$ D decreased by 31 % and slugs with size of $l_s > 20$ D decreased by 95 %.

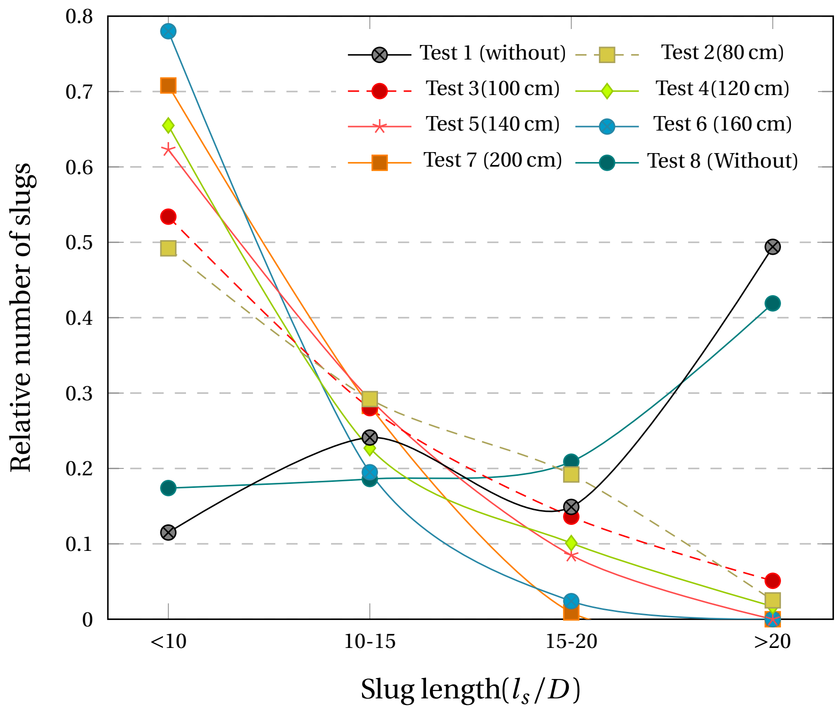


Figure 5.12: all graphs from experiment 6

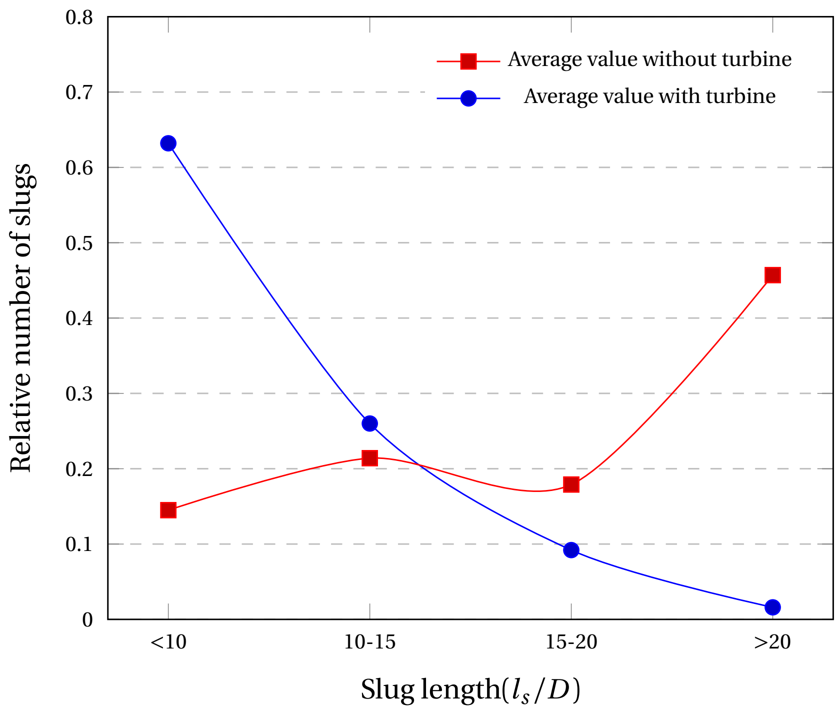


Figure 5.13: Comparison of average values with and without turbine from experiment 6

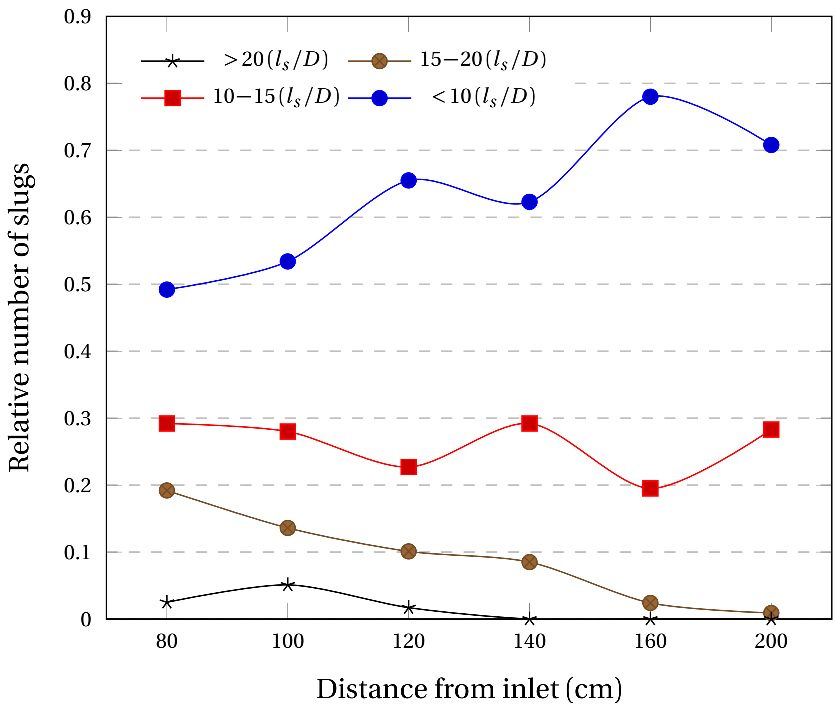


Figure 5.14: Effect of turbine placement on slug sizes and relative number of slugs

Seen from Figure 5.14 above, slugs with size $l_s > 20$ D were not observed for placement 140-200 cm from the inlet. For slugs with size $l_s = 15{-}20$ D, it was seen that the relative number of slugs decreased as the turbine was placed longer distance from the inlet. The opposite was the case for slugs with $l_s < 10$ D as the relative number increased as the turbine was place longer distance from the inlet.

From Figure 5.15 on the next page, it was seen that the liquid height increased close to the propeller which seemed to accumulate a large number of slugs, possibly explaining the increased frequency. Further, from Figure 5.16, as the liquid slug flowed across the turbine, it was seen from $t = 0.25\,\text{s}$ and $t = 0.375\,\text{s}$ that cavitation happened, probably caused by Bernoulli effect as the flow area decreased.

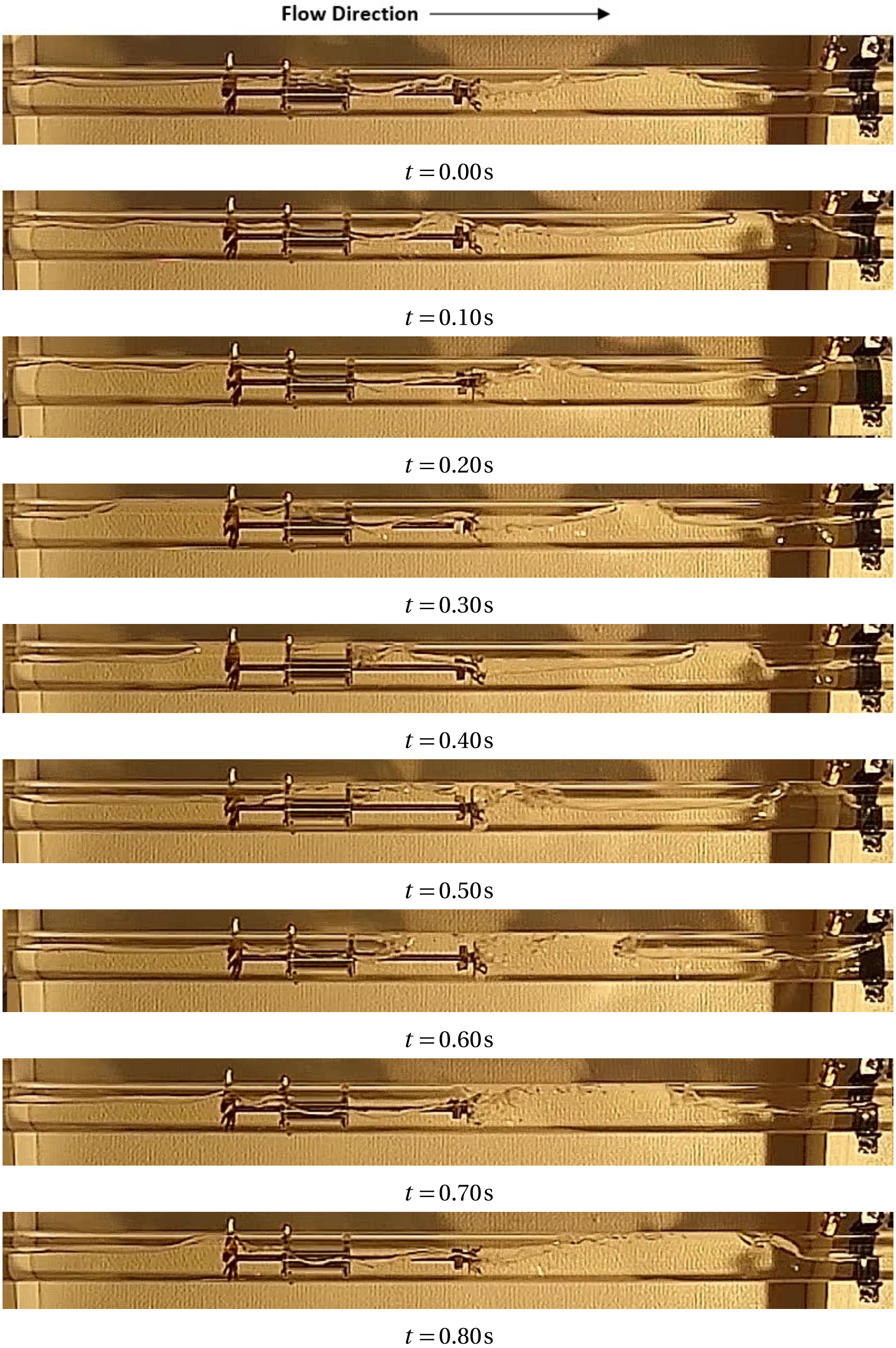


Figure 5.15: Formation of small slug over turbine in horizontal direction with rotation, $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and medium gas rate

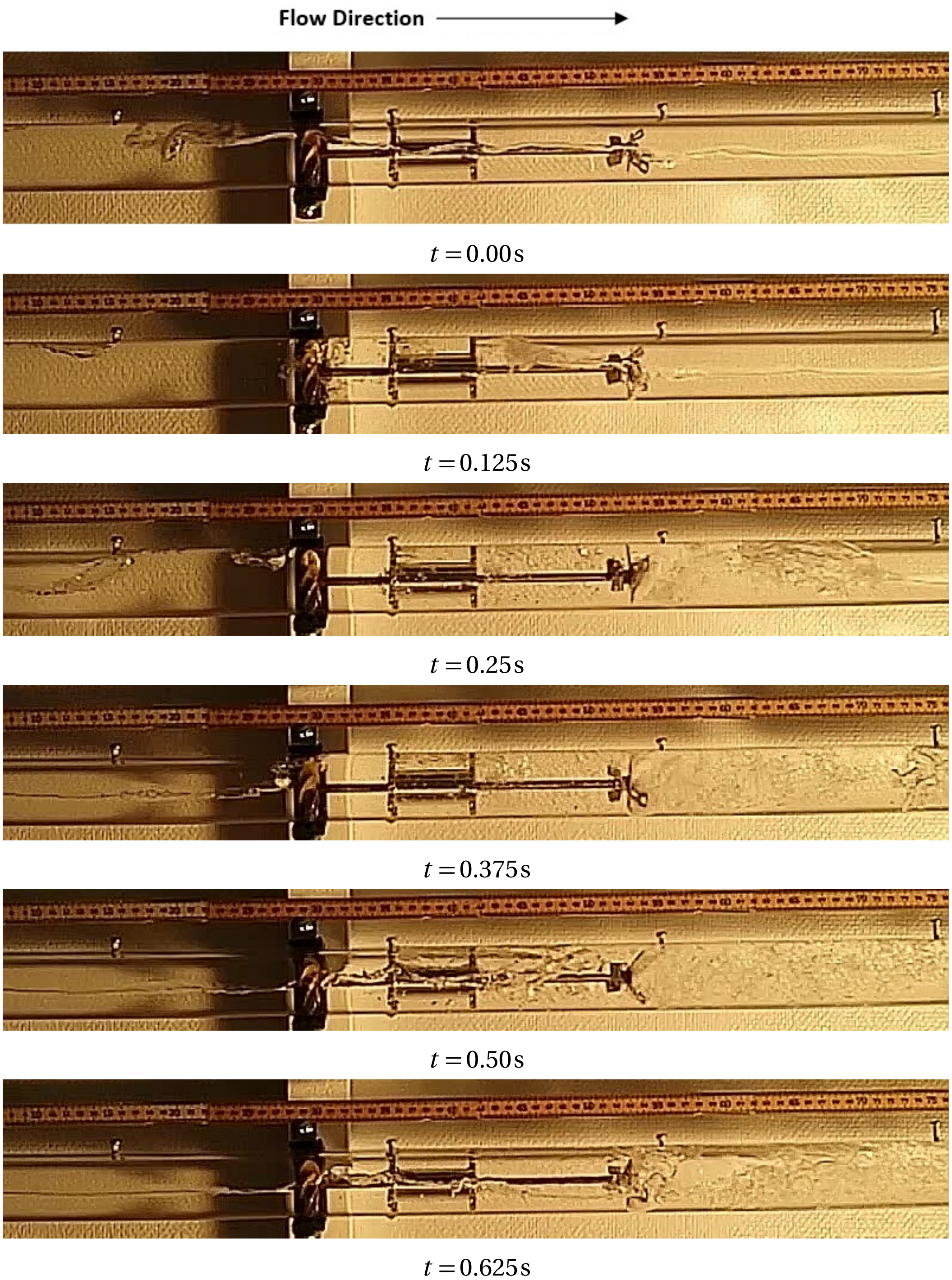


Figure 5.16: Slug flow over turbine in horizontal flow direction, $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ and high gas rate

5.7 Summary

To summarize the experimental results, key findings are listed as bullet points below and in Table 5.1;

- From experiments 1 and 2 in the horizontal flow direction it was identified;
  - Slug frequency with turbine increased
  - Number of large slugs decreased drastically with the turbine
  - Frequency for slugs with $l_s > 10$ D decreased with the turbine
- From experiments 3 and 4 with bend sections it was identified;
  - Insignificant difference with the turbine
  - Two bend sections as opposed to one had 45 % lower slug frequency.
- From experiment 5 in the vertical flow direction it was identified;
  - Small impact with the turbine
  - Frequency was not affected
  - Turbine stopped as large Taylor bubbles ascended through the turbine
- From experiment 6 in the horizontal flow direction it was identified;
  - Slug frequency with turbine increased
  - Number of large slugs decreased drastically with the turbine
  - Frequency for slugs with $l_s > 10$ D decreased with the turbine
  - Placement further away from the inlet reduced number of large slugs compared to placement close to the inlet

Table 5.1: Test results summarized from all experiments. Extended information in Appendix A

		Number of slugs by size			
Experiment	Test	< 10 D	10−15 D	15−20 D	> 20 D
Experiment 1	With turbine	107	37	4	0
	Without turbine	26	19	24	29
Experiment 2	With turbine	96	28	5	0
	Without turbine	25	44	24	10
Experiment 3	With turbine	77	43	23	0
	Without turbine	80	37	24	0
Experiment 4	With turbine	55	24	3	0
	Without turbine	51	23	2	0
Experiment 5	With turbine	26	22	16	11
	Without turbine	16	24	23	14
Experiment 6	Test 1	10	21	13	43
	Test 2	59	35	23	3
	Test 3	63	33	16	6
	Test 4	78	27	12	2
	Test 5	66	31	9	0
	Test 6	96	24	3	0
	Test 7	75	30	1	0
	Test 8	15	16	18	36

Chapter 6

Discussion

The objective of this thesis was to review multiphase flow with special emphasis on slug phenomena, followed by experiments to evaluate the use of a rotating device to mechanically break down slugs in the gas-liquid interface and/or influence multiphase flow in any significant and beneficial way. The results indicated varying impacts from the turbine depending on flow configuration and placement. The largest impacts on the flow behaviour was found in experiments 1, 2 and 6 as all these experiments studied the impacts of the turbine when placed in the horizontal flow direction. The hydrodynamic instability at the gas-liquid interface created slugs early in the flow loop, thus making it possible to study the impacts of the turbine without the vertical section affecting the flow.

The dimensions of the flow loop configurations limited the experimental study substantially. Terrain induced slugging required greater pressure build-ups than the dimensions in the experimental study would allow. This was caused by short lengths and relatively low liquid flow rate. The horizontal flow loop was not as much limited by these factors as hydrodynamic slugs developed over a broader range of parameters.

Terrain induces slugging and hydrodynamic slugging are very different in nature. Terrain induced slugs occurs because of geometry allowing for liquid accumulation at low spots and pressure build-ups while hydrodynamic slugs occurs because of flow conditions and interaction between gas and liquid phase. Terrain induced slugs are considered more harsh than hydrodynamic slugs because of large pressure and flow rate fluctuations.

Terrain induced slugging did not occur in the flow loops containing bend sections because of the dimensions and flow conditions. The turbine did not have any impact on the flow because there was nothing to fix at the low points of the bend sections since gas was transported efficiently with the liquid flow as seen in Figure 5.6. Slug flow occurred in the flow loops containing bend section, but the formation of the slugs took place at other places of the flow loops rather than the base of the bend sections. It was discussed briefly in Section 4.2 why terrain induced slugging did not occur and found to be caused by the short length of the inclined sections not allowing for pressure build-ups. It was mentioned that the lengths of the bend section should have been at least 12-13 m and 25 m using the Bøe criterion, but the assumptions for the calculations made the perfect conditions for terrain induced slugging occurring and the length should probably been even longer.

It was identified that the turbine was able to break down small gas bubbles ascending over the turbine in the vertical direction as seen from snapshots in Figure 5.8, but was not able to break down Taylor bubbles as seen from snapshots in Figure 5.9. When Taylor bubbles ascended over the turbine, rotation stopped because of a vortex at the point right above the propeller probably caused by the change of flow direction by the propeller. The liquid velocity upwards was reduced and further accelerated downwards by the gravitation. It was believed that this phenomenon stopped the device from rotating.

The horizontal flow loop with the test conditions resulted in hydrodynamic slugging. These hydrodynamic slugs were caused by instabilities at the gas-liquid interface and the slugs increased in size along the flow. The turbine altered the flow by increasing the slug frequency and reducing the size of the slugs. From the slow motion footage in Figure 5.15, it was seen that the liquid height at the position of the propeller increased which reduced the height of the gas at the same position. Studying the Kelvin-Helmholtz instability criterion of Equation 3.1 when the gas height is reduced, revealed that instability were more likely to occur and create slugs, explaining the increase of frequency with the turbine. In the experiments in this study, local effects were studied, but larger scale and different test intervals might have led to other results because of interaction between slugs along the flow. The amount of large slugs were drastically reduced, but Figure 5.14 illustrated that short distance from turbine to test interval might have caused these results. It was, however, evident that under these experimental conditions that the turbine reduced the size of the slugs over a short distance.

It was mentioned briefly in Section 4.3 that the device reduced the surface area by approximately 37.5 %. This constriction of flow area would affect the production rate in a negative way. From Figure 5.16, it was seen that cavitation happened as the already created slug flowed through the turbine. Cavitation is associated with fast formation and breakdown of gas bubbles due to Bernoulli effect, here created as the result of reducing the flow area.

Slug lengths are associated with uncertainty because of random flow behaviour since slugs interact with each other over large distances and might coalesce to larger slugs as well as slugs might break down. Even at the small scale of the experiments in this study, slugs grew and broke down in the test interval which is why large increments were used for the size distributions. The flow loops in this study were short and only local effects were studied. By studying Figure 5.14, it was seen that the number of large slugs decreased significantly when the device was placed further away from the inlet. The device placement very close to the test interval, so that slugs did not have the opportunity to accumulate to larger slugs, might have caused this. It could also be caused by the impacts of the device on the flow behaviour, but yet again not allowing for accumulation of larger slugs before the test interval. It was, however, evident that there was an impact from the device on this scale despite the large uncertainties of these experiments. Uncertainty also related to the method used to gather the results as impacts have been captured on film and further results from visual inspections of the films.

Chapter 7

Conclusion

This study was set out to explore the possibilities of utilizing a turbine to mechanically affect the slug flow behaviour in undulated horizontal wells and pipeliner-riser systems. As terrain induced slugging did not occur in any of the flow loops, it was decided to study the impacts from the turbine on hydrodynamic generated slugs. The nature of hydrodynamic slugs are very different from the nature of terrain induced slugs. hydrodynamic slugs are caused by flow instability and interaction between gas and liquid phase whereas terrain induced slugs are created from liquid accumulation at low spots. This means that the turbine is not expected to have the same outcome on terrain induced slugging as the results in this study. New experiments should be conducted with a flow loop where terrain induced slugging occurs to study the impacts of the turbine on this flow.

7.1 Concluding remarks

The findings of this study are summarized below;

- Slug flow occurred in the flow loops caused by hydrodynamic instability as a result of flowing conditions, but terrain induced slugging did not occur in any of the flow loops likely because to the dimensions.
- Based on the results in experiment 5, it was indicated that the impact of the turbine in the vertical flow direction was small, probably because the turbine stopped rotating when large Taylor bubbles ascended over the turbine and the liquid phase velocity was reduced.

- Based on the results from experiments 3 and 4, there was no impact from the turbine on the flow behaviour in the bend sections.
- Based on the results from experiments 1, 2 and 6 in the flow loop consisting of horizontal flow sections, slug flow tended to occur at the same spot in the pipe with the test conditions. It was believed that placing the turbine around this region would yield results as the turbine could break down the slugs as they were generated. It was seen that the frequency increased while the size of each individual slug was reduced. It was found that slugs tended to form over the turbine as the liquid height was locally increased and waves grew due to flow instabilities. Further, it was seen that placement of the turbine closer to the test interval resulted in the lowest number of with size $l_s > 15$ D as the slugs did not have the opportunity to grow in the short distance.

7.2 Future work

The experiences from this study has identified some improvement areas with the original configurations and my suggestions for changes in future work are;

- First, To evaluate the use of the turbine for terrain induced slugging, the dimensions must be scaled much larger so that liquid slugs can accumulate at low points. With larger dimensions comes possibilities of studying placement of turbine in inclined section to evaluate optimal positioning. As discussed in Section 3.4.3, the flow in the downward flow direction have to be effectively stratified. Investigation on whether or not the turbine could affect this criterion could be feasible.
- Further, to evaluate the impact of the rotational speed, implement a motor to control RPM of the turbine. This would also affect the vertical section as the turbine would no longer stop when Taylor bubbles ascends across the turbine.
- The use of a capacitance sensor or digital manometer connected to a computer would extend the study to larger time scales in addition to less processing time before the data analysis.
- Identify the possibility of a new device to transport the gas in inclined section down to the base point or modifying the device in this study to the extent that it is used for transportation of gas in the downward inclined section.

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Appendix A

Experiments

A.1 Experiment 1

Table A.1: Results with turbine 120 cm from inlet resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	With turbine	Without turbine
Number of slugs by size		
$< 10D$	107	26
$10-15D$	37	19
$15-20D$	4	24
$> 20D$	0	29
Total number of slugs	148	98
Relative number of slugs (l_s/D)		
< 10	0.723	0.265
$10-15$	0.250	0.194
$15-20$	0.027	0.245
> 20	0.000	0.296
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.902	0.264
$15-20D$	0.098	0.333
$> 20D$	0.000	0.403
Frequency, f_s	0.617	0.408
Frequency, f_s for $l_s > 10D$	0.171	0.300
Reduction	0.446	0.108

A.2 Experiment 2

Table A.2: Results with turbine 195 cm from inlet resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	With turbine	Without turbine
Number of slugs by size		
$< 10D$	96	25
$10-15D$	28	44
$15-20D$	5	24
$> 20D$	0	10
Total number of slugs	129	103
Relative number of slugs (l_s/D)		
< 10	0.744	0.243
$10-15$	0.217	0.427
$15-20$	0.039	0.233
> 20	0.000	0.097
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.848	0.564
$15-20D$	0.152	0.308
$> 20D$	0.000	0.128
Frequency, f_s	0.538	0.429
Frequency, f_s for $l_s > 10D$	0.138	0.325
Reduction	0.400	0.104

A.3 Experiment 3

Table A.3: Results with turbine in bend section resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	With turbine	Without turbine
Number of slugs by size		
$< 10D$	77	80
$10-15D$	43	37
$15-20D$	23	24
$> 20D$	0	0
Total number of slugs	143	141
Relative number of slugs (l_s/D)		
< 10	0.538	0.567
$10-15$	0.301	0.262
$15-20$	0.161	0.170
> 20	0.000	0.000
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.652	0.607
$15-20D$	0.348	0.393
$> 20D$	0.000	0.000
Frequency, f_s	0.596	0.588
Frequency, f_s for $l_s > 10D$	0.275	0.254
Reduction	0.321	0.333

A.4 Experiment 4

Table A.4: Results with turbine in two bend sections resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	With turbine	Without turbine
Number of slugs by size		
$< 10D$	55	51
$10-15D$	24	23
$15-20D$	3	2
$> 20D$	0	0
Total number of slugs	82	76
Relative number of slugs (l_s/D)		
< 10	0.671	0.671
$10-15$	0.293	0.303
$15-20$	0.037	0.026
> 20	0.000	0.000
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.889	0.920
$15-20D$	0.111	0.080
$> 20D$	0.000	0.000
Frequency, f_s	0.342	0.317
Frequency, f_s for $l_s > 10D$	0.113	0.104
Reduction	0.229	0.213

A.5 Experiment 5

Table A.5: Results with turbine in vertical section resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	With turbine	Without turbine
Number of slugs by size		
$< 10D$	26	16
$10-15D$	22	24
$15-20D$	16	23
$> 20D$	11	14
Total number of slugs	75	77
Relative number of slugs (l_s/D)		
< 10	0.347	0.208
$10-15$	0.293	0.312
$15-20$	0.213	0.299
> 20	0.147	0.182
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.449	0.393
$15-20D$	0.327	0.377
$> 20D$	0.224	0.230
Frequency, f_s	0.313	0.321
Frequency, f_s for $l_s > 10D$	0.204	0.254
Reduction	0.108	0.067

A.6 Experiment 6

Table A.6: Results without turbine and turbine 80 cm from inlet resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	Test #1 Without turbine	**Test #2** 80 cm from inlet
Number of slugs by size		
$< 10D$	10	59
$10-15D$	21	35
$15-20D$	13	23
$> 20D$	43	3
Total number of slugs	87	120
Relative number of slugs (l_s/D)		
< 10	0.115	0.492
$10-15$	0.241	0.292
$15-20$	0.149	0.192
> 20	0.494	0.025
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.279	0.574
$15-20D$	0.169	0.377
$> 20D$	0.558	0.049
Frequency, f_s	0.363	0.500
Frequency, f_s for $l_s > 10D$	0.321	0.254
Reduction	0.042	0.246

Table A.7: Results with turbine 100 cm and 120 cm from inlet resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	Test #3 100 cm from inlet	**Test #4** 120 cm from inlet
Number of slugs by size		
$< 10D$	63	78
$10-15D$	33	27
$15-20D$	16	12
$> 20D$	6	2
Total number of slugs	118	119
Relative number of slugs (l_s/D)		
< 10	0.534	0.655
$10-15$	0.280	0.227
$15-20$	0.136	0.101
> 20	0.051	0.017
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.600	0.659
$15-20D$	0.291	0.293
$> 20D$	0.109	0.049
Frequency, f_s	0.492	0.496
Frequency, f_s for $l_s > 10D$	0.229	0.171
Reduction	0.263	0.325

Table A.8: Results with turbine 140 cm and 160 cm from inlet resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	Test #5 140 cm from inlet	**Test #6** 160 cm from inlet
Number of slugs by size		
$< 10D$	66	96
$10-15D$	31	24
$15-20D$	9	3
$> 20D$	0	0
Total number of slugs	106	123
Relative number of slugs (l_s/D)		
< 10	0.623	0.780
$10-15$	0.292	0.195
$15-20$	0.085	0.024
> 20	0.000	0.000
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.775	0.889
$15-20D$	0.225	0.111
$> 20D$	0.000	0.000
Frequency, f_s	0.442	0.513
Frequency, f_s for $l_s > 10D$	0.167	0.113
Reduction	0.275	0.400

Table A.9: Results with turbine 200 cm from inlet and without turbine resulting from a period of 4 minutes. $u_{SL} = 0.20\,\mathrm{m\,s^{-1}}$ & high gas rate.

	Test #7 200 cm from inlet	**Test #8** Without turbine
Number of slugs by size		
$< 10D$	75	15
$10-15D$	30	16
$15-20D$	1	18
$> 20D$	0	36
Total number of slugs	106	86
Relative number of slugs (l_s/D)		
< 10	0.708	0.174
$10-15$	0.283	0.186
$15-20$	0.009	0.209
> 20	0.000	0.419
Relative number of slugs for $l_s > 10D$		
$10-15D$	0.968	0.225
$15-20D$	0.032	0.254
$> 20D$	0.000	0.507
Frequency, f_s	0.442	0.358
Frequency, f_s for $l_s > 10D$	0.129	0.296
Reduction	0.313	0.063