STUDY OF TWO AND THREE-PHASE FLOWS IN LARGE DIAMETER HORIZONTAL PIPELINES

A Thesis Presented to

The Faculty of the
Fritz J. and Dolores H. Russ
College of Engineering and Technology
Ohio University

In Partial Fulfillment
of the Requirement for the Degree
Master of Science

by

Ajay Malhotra

November, 1995
# TABLE OF CONTENTS

**LIST OF TABLES** ........................................................................................................ ii

**LIST OF FIGURES** ....................................................................................................... iv

1. **INTRODUCTION** ........................................................................................................ 1

2. **LITERATURE REVIEW** .......................................................................................... 16
   2.1 **FUNDAMENTALS OF TWO-PHASE FLOW IN PIPES** ........................................ 16
   2.2 **PREVIOUS WORK** ............................................................................................... 25

3. **EXPERIMENTAL SETUP AND PROCEDURE** .......................................................... 39
   3.1 **DESCRIPTION OF THE FLOW LOOP** ............................................................... 39
      3.1.1 Low Pressure System .................................................................................. 39
      3.1.2 High Pressure System ................................................................................ 43
   3.2 **PROCEDURE AND TEST MATRIX** ..................................................................... 45

4. **EXPERIMENTAL RESULTS AND DISCUSSION** ................................................. 48
   4.1 **TWO-PHASE OIL-WATER, FULL PIPE FLOWS** ................................................ 48
      4.1.1 Flow Patterns for Oil-Water Flows ............................................................... 48
      4.1.2 Pressure Gradient ....................................................................................... 51
      4.1.3 Water Film Heights .................................................................................... 62
      4.1.4 Liquid Holdup ............................................................................................. 81
   4.2 **THREE-PHASE OIL-WATER-GAS, STRATIFIED FLOWS** ............................... 91
      4.2.1 Film Heights ............................................................................................... 91
      4.2.2 Holdup ......................................................................................................... 97
   4.3 **THREE-PHASE BRITOL-WATER-GAS, SLUG FLOW** ........................................ 101
      4.3.1 Film Thicknesses ....................................................................................... 105
      4.3.2 Holdup ....................................................................................................... 115

5. **CONCLUSIONS** ...................................................................................................... 124

**REFERENCES** ........................................................................................................... 127

**APPENDIX A** ............................................................................................................. 130

**APPENDIX B** ............................................................................................................. 131
## LIST OF TABLES

<table>
<thead>
<tr>
<th>Table 2.1:</th>
<th>Density and viscosity data for Water, SN-250 and 150-SB Oils (Arirachakaran, 1983)</th>
<th>33</th>
</tr>
</thead>
<tbody>
<tr>
<td>Table 3.1:</td>
<td>Properties of the oils LVT 200 and Britol 50T</td>
<td>47</td>
</tr>
<tr>
<td>Table 4.1:</td>
<td>Calculated pressure gradients for LVT 200 oil and water at different concentrations using the single-phase relationships</td>
<td>60</td>
</tr>
<tr>
<td>Table 4.2:</td>
<td>Calculated pressure gradients for Britol 50T oil and water at different concentrations using the single-phase relationships</td>
<td>61</td>
</tr>
<tr>
<td>Table 4.3:</td>
<td>Comparison of input to <em>insitu</em> water velocities at different water concentrations in full pipe flow for LVT 200</td>
<td>86</td>
</tr>
<tr>
<td>Table 4.4:</td>
<td>Comparison of input to <em>insitu</em> water velocities at different water concentrations in full pipe flow for Britol 50T</td>
<td>87</td>
</tr>
<tr>
<td>Table 4.5:</td>
<td>Calculated pressure gradients for LVT 200 oil and water at different concentrations using the <em>insitu</em> water velocities</td>
<td>89</td>
</tr>
<tr>
<td>Table 4.6:</td>
<td>Calculated pressure gradients for Britol 50T oil and water at different concentrations using the <em>insitu</em> water velocities</td>
<td>90</td>
</tr>
<tr>
<td>Table 4.7:</td>
<td>Comparison of total liquid holdups at different pressures for a 50:50 mixture of LVT 200 and water in stratified three-phase flow</td>
<td>99</td>
</tr>
<tr>
<td>Table 4.8:</td>
<td>Comparison of water holdups at different pressures for a 50:50 mixture of LVT 200 and water in stratified three-phase flow</td>
<td>100</td>
</tr>
<tr>
<td>Table 4.9:</td>
<td>Comparison of gas holdups at different pressures for a 50:50 mixture of LVT 200 and water in stratified three-phase flow</td>
<td>102</td>
</tr>
<tr>
<td>Table 4.10:</td>
<td>Comparison of <em>insitu</em> velocities for a 50:50 mixture of LVT 200 and water in stratified three-phase flow at atmospheric pressure</td>
<td>103</td>
</tr>
<tr>
<td>Table 4.11:</td>
<td>Comparison of <em>insitu</em> velocities for a 50:50 mixture of LVT 200 and water in stratified three-phase flow at a pressure of $1.7 \times 10^5$ N/m$^2$</td>
<td>104</td>
</tr>
</tbody>
</table>
Table 4.12: *Insitu* holdups of Britol 50T at different oil-water concentrations and gas velocities in three-phase slug flow ........................................ 116

Table 4.13: *Insitu* holdups of water at different oil-water concentrations and gas velocities in three-phase slug flow ........................................ 117

Table 4.14: *Insitu* fractions of gas at different oil-water concentrations and gas velocities in three-phase slug flow .............. 118

Table 4.15: Ratio of *insitu* to input velocities of gas at different oil-water concentrations and gas velocities in three-phase slug flow .............. 120

Table 4.16: Ratio of *insitu* to input velocities of water at different oil-water concentrations and gas velocities in three-phase slug flow .............. 121

Table 4.17: Ratio of *insitu* to input velocities of Britol 50T at different oil-water concentrations and gas velocities in three-phase slug flow ........................................ 122
LIST OF FIGURES

Figure 1.1(a): Description of flow pattern classifications for oil-water flows (Oglesby, 1979) ................................................................. 4

Figure 1.1(b): Description of flow pattern classifications for oil-water flows (Oglesby, 1979) ................................................................. 5

Figure 1.2: Flow pattern map for two-phase, oil-water flows (Oglesby, 1979) ....... 6

Figure 1.3: Two-phase liquid-gas flow patterns (Ai Hsin Lee, 1993) ................. 9

Figure 1.4: Three-phase water-oil-gas flow patterns (Ai Hsin Lee, 1993) .......... 10

Figure 1.5: Flow regime map for a water-CO₂ flow system (Ai Hsin Lee, 1993) ................................................................. 11

Figure 1.6: Flow pattern map for 50% water-50% oil-gas flows (Ai Hsin Lee, 1993) ...................................................................... 13

Figure 2.1: Schematic diagram of two-phase stratified flow (Govier and Aziz, 1972) ........................................................................ 22

Figure 2.2: Pressure gradients vs. water concentration (Guzov, 1973) ............ 28

Figure 2.3: Pressure gradient vs. input water fraction (Laflin and Oglesby, 1976) ........................................................................ 31

Figure 2.4: Flow pattern map for oil-water flows (Laflin and Oglesby, 1976) .... 32

Figure 2.5: Pressure gradient vs. input water fraction (Oglesby, 1979) (Oil No. 2, mixture velocities = 1.0 and 1.5 m/s).......................... 35

Figure 3.1: Layout of the low pressure experimental system .......................... 40

Figure 3.2: Test section ........................................................................... 41

Figure 3.3: Layout of the high pressure experimental system ....................... 44

Figure 4.1: Photographs of the flow regimes observed .................................. 49

Figure 4.2: Variation of pressure drop with input water percentage for LVT 200 oil ........................................................................ 52
Figure 4.3: Variation of pressure drop with input water percentage for Britol 50T................................................................. 56

Figure 4.4: Percentage of Britol when it touches the bottom of the pipe............. 58

Figure 4.5: Sample collection with a pitot tube in the pipeline ...................... 64

Figure 4.6: Variation of water percentage with vertical position
(Oil: LVT 200; Total superficial velocity = 0.4 m/s).......................... 65

Figure 4.7: Variation of water percentage with vertical position
(Oil: LVT 200; Total superficial velocity = 0.5 m/s)......................... 66

Figure 4.8: Variation of water percentage with vertical position
(Oil: LVT 200; Total superficial velocity = 0.6 m/s)......................... 67

Figure 4.9: Variation of water percentage with vertical position
(Oil: LVT 200; Total superficial velocity = 0.8 m/s)......................... 69

Figure 4.10: Variation of water percentage with vertical position
(Oil: LVT 200; Total superficial velocity = 1.0 m/s)....................... 70

Figure 4.11: Variation of water percentage with vertical position
(Oil: LVT 200; Total superficial velocity = 1.2 m/s)....................... 71

Figure 4.12: Variation of water percentage with vertical position
(Oil: LVT 200; Total superficial velocity = 1.4 m/s)....................... 72

Figure 4.13: Variation of water percentage with vertical position
(Oil: Britol 50T; Total superficial velocity = 0.4 m/s)...................... 75

Figure 4.14: Variation of water percentage with vertical position
(Oil: Britol 50T; Total superficial velocity = 0.6 m/s)...................... 76

Figure 4.15: Variation of water percentage with vertical position
(Oil: Britol 50T; Total superficial velocity = 0.8 m/s)...................... 77

Figure 4.16: Variation of water film height vs. total superficial velocity
for LVT 200 oil........................................................................... 79

Figure 4.17: Variation of water film height vs. total superficial velocity
for Britol 50T oil....................................................................... 80
Figure 4.18: Insitu to input volume fraction of water vs. total superficial velocity for LVT 200 oil.................................................................................................................. 82

Figure 4.19: Insitu to input volume fraction of water vs. total superficial velocity for Britol 50T oil .................................................................................................................. 83

Figure 4.20: Effect of gas velocity on the total film thickness at different liquid velocities (System at atmospheric pressure; 50:50 LVT 200-water mixture) ........................................................................................................... 92

Figure 4.21: Effect of gas velocity on the total film thickness at different liquid velocities (System at 1.7*10^5 N/m^2; 50:50 LVT 200-water mixture) .................................................................................................................. 93

Figure 4.22: Effect of gas velocity on the water film thickness at different liquid velocities (System at atmospheric pressure; 50:50 LVT 200-water mixture) ........................................................................................................... 94

Figure 4.23: Effect of gas velocity on the water film thickness at different liquid velocities (System at 1.7*10^5 N/m^2; 50:50 LVT 200-water mixture) ........................................................................................................... 95

Figure 4.24: Total film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.2 m/s; Oil: Britol 50T).......... 106

Figure 4.25: Total film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.4 m/s; Oil: Britol 50T).......... 107

Figure 4.26: Total film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.6 m/s; Oil: Britol 50T).......... 108

Figure 4.27: Total film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.8 m/s; Oil: Britol 50T).......... 109

Figure 4.28: Water film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.2 m/s; Oil: Britol 50T).......... 111

Figure 4.29: Water film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.4 m/s; Oil: Britol 50T).......... 112

Figure 4.30: Water film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.6 m/s; Oil: Britol 50T).......... 113

Figure 4.31: Water film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.8 m/s; Oil: Britol 50T).......... 114
CHAPTER 1
INTRODUCTION

Co-current two and three-phase flow is encountered frequently in the petroleum industry. The widespread existence of multiphase flow and its importance to industrial units has prompted extensive research in this field. This type of flow is seen in pipelines, oil producing wells and associated flow lines, separators, dehydration units, evaporators and other processing equipment. The nature of multiphase flow is extremely complicated due to the existence of various flow patterns and different mechanisms governing them. It is therefore important to understand the nature and behavior of flow in multiphase systems.

In the initial stages of an oil well, the flow consists of mainly oil and natural gas. As the reserves of oil and gas in the oil wells decrease, sea water and CO₂ are pumped into the well for enhanced recovery purposes. Many of the wells are located in remote areas such as Alaska and subsea. It is therefore not practicable to separate the multiphase mixtures at these sites. The mixture from several wells is combined and sent to a central gathering station in a single multiphase pipeline, where the oil, water and gas are separated.

This flow causes widespread corrosion problems in the pipelines and results in considerable losses due to damaged equipment, repairs and lost production due to down time. Carbon dioxide dissolves in the water to form a weak but corrosive carbonic acid and causes extensive corrosion. The extent of corrosion depends on the composition of
sea water, the pH of the solution, temperature, pressure and the type of flow.

The multiphase pipelines are situated in areas subject to severe weather or unsuitable for easy repairs. Therefore, repair, maintenance, clean up or replacement costs are extremely high. The use of expensive, corrosion resistant pipe materials is not a suitable solution. The use of corrosion inhibitors is an important method to curb corrosion and is being tested and used in the industry. Corrosion inhibitors are substances containing organics that adsorb to the metal surface of the pipeline and form a protective film to prevent corrosion. The effectiveness of the inhibitor depends on the composition of the pipeline material, the inhibitor composition and the type of flow of the fluids. It is necessary to introduce the inhibitor in the phase in contact with the pipe wall and this can be accomplished if the flow mechanisms, under different conditions, are known.

It is necessary to study and understand the flow patterns in pipelines. The relative motion between the metal and the fluid greatly effects the corrosion mechanism. Experiments have to be carried out to determine and enhance the lifetime of the oil pipelines. The flow characteristics have to be studied to determine whether the oil or water phase is in contact with the pipe wall, with or without the introduction of gas. These studies will enable researchers to decide whether to use oil or water soluble corrosion inhibitors, under different conditions and in different flow regimes.

Two-phase flow in pipelines is classified as: (1) gas-liquid flow, (2) liquid-liquid flow, (3) gas-solid flow and (4) liquid-solid flow. Most of the work done in horizontal and vertical pipes have been for the flow of gas and liquid. Little conclusive work has been reported for the co-current flow of two immiscible liquids in horizontal
pipes and even less when there is a third gas phase. Figure 1.1 (a & b) shows the flow patterns observed for two-phase oil-water flows and Figure 1.2 is a typical flow regime map depicting the transition of the regimes (Oglesby, 1979) for three experimental oils. These oils had viscosities of 167 cp, 61 cp and 32 cp, respectively.

Oil-water flows can be broadly classified to have two principal flow patterns, namely stratified (oil and water as separate layers) and mixed (the oil and water mixture flows as a dispersion). In these flow regimes, the phase that coats the pipe walls is called the "continuous", "external" or the "dominant" phase and the other, mixed in the continuous phase, is the "dispersed" or the "internal" phase. Many interim flow patterns are observed as the transition occurs from stratified to completely mixed flow, with a change in the input concentrations of the two phases and an increase in the total superficial velocity of the mixture. A detailed description of all the different regimes that have been observed as this transition takes place is given below.

The flow regimes were observed by Oglesby (1979) as shown in Figures 1.1(a) and (b) and Figure 1.2, for the oils described above. Other researchers have conducted similar experiments with different oils and observed many of these flow patterns.

The stratified or segregated flow regime, depicted as regime A in Figure 1.1(a), occurs from the lowest to about 0.25 m/s liquid velocity (region A, Figure 1.2), for all input oil-water compositions and is defined as the flow of the liquids in two distinct layers, with no mixing at the interface. As the mixture velocity is increased, some mixing occurs at the interface giving rise to semi-segregated flow (regime B, Figure 1.1(a)). This regime occurs for the ranges shown in region B of Figure 1.2. The other flow regimes are
Segregated - no mixing at the interface

Semi-segregated - some mixing at the interface

Semi-mixed - segregated flow of a dispersion and "free" phase. Bubbly interface. Dispersion volume less than half the total pipe volume.

Mixed - same as the above coding but with the dispersion occupying more than half the total pipe volume.

Figure 1.1(a) Description of Flow Pattern Classifications for Oil-Water Flows (Oglesby, 1979)
Flow Direction →

FLOW PATTERN CODE

Oil Dominant  Water Dominant

Annular of concentric - core of one phase within the other phase

Example: water core in an oil layer

G

Slug - phases alternately occupying the pipe volume as a free phase or as a dispersion

II  I

Semi-dispersed - some vertical gradient of fluid concentrations in the mixture.

E  M

Fully dispersed Homogeneous flow.

F  N

Figure 1.1(b) Description of Flow Pattern Classifications for Oil-Water Flows (Oglesby, 1979)
Figure 1.2 Flow Pattern Map for Two-Phase, Oil-Water Flows (Oglesby, 1979)
separated by a darkened line which represents the phase inversion point. In oil-water flows, increasing the concentration of the "dispersed" phase beyond a certain critical point, causes it to become the "continuous" phase and the other phase, which no longer coats the walls of the pipeline, is seen to become the "dispersed" phase. For example, as water is added to an oil continuous phase a critical composition is reached where the phases 'invert' and the water becomes the continuous phase with oil as the dispersed phase.

The flow is said to be semi-mixed (Regime's C and K, Figure 1.1(a)) when there is a segregated flow of a dispersion and a 'free' phase and the dispersion volume is less than half the total pipe volume. The regions C and K in Figure 1.2 depict the semi-mixed flow regime with oil and water as the dominant phases, respectively. Mixed flow occurs when the oil-water dispersion occupies more than half the pipe volume and is observed to occur in the regions D and L for the oil and water dominant phases, respectively. Annular flow develops when there is a core of one phase within the other phase, which is in contact with the walls of the pipeline and this regime is marked G on the map. Slug flow is seen to develop after the inversion of the mixture in the ranges marked H and I, and has been observed only by Oglesby (1979) for the three experimental oils flowing as the second phase along with water in the pipeline.

Slug flow in liquid-liquid flow has been defined as a flow pattern when the phases alternately occupy the pipe volume as a free phase or as a dispersion. When some steep gradients of fluid concentrations in the mixture are incurred, the flow pattern is termed as semi-dispersed and is observed in the regions E and M for oil and water dominant
phases, respectively. Beyond these regions the flow regime becomes fully dispersed when the mixture flows as a homogeneous phase, with no appreciable changes in concentration in the pipeline. The homogeneous flow patterns are seen to occur in the regions F and N on the flow regime map for oil and water as the dominant phases, respectively.

A comparison of all the flow regime maps studied shows that the effects of the oil viscosity, density and the interfacial tension between the oil-water phases have not been fully accounted for and more research has been recommended. However, Arirachakaran et al. (1989) did conclude that the input water fraction required to invert an oil-water mixture decreases with an increase in the oil viscosity.

Flow regimes in two phase liquid-gas and three-phase oil-water-gas flows vary with the relative amounts of oil-water in the liquid phase and the liquid and gas velocities. These include stratified, intermittent and annular flows and are shown in Figures 1.3 and 1.4 for two and three-phase flows, respectively (Lee, 1993). Flow regimes for two-phase water-gas flows and three-phase oil-water-gas flows have been observed to be similar and the only difference is the presence of an oil layer between the gas and the water phases. A typical flow regime map developed for two-phase water-gas flow is also shown in Figure 1.5 (Lee, 1993).

The stratified flow regime occurs at low liquid and gas velocities, as seen in Figure 1.5, with the gas and liquid phases flowing in separate layers at the top and bottom of the pipe, respectively. Stratified flow can be further sub-divided into smooth stratified, wavy stratified and rolling wave. Wavy stratified flow develops with an increase in the gas velocity. A further increase in the gas velocity causes these two dimensional waves
Flow Direction

- Smooth stratified
- Wavy stratified
- Rolling wave
- Plug flow
- Slug flow
- Annular flow

Figure 1.3 Two-Phase Liquid-Gas Flow Patterns (Ai Hsin Lee, 1993)
Flow Direction

- Smooth stratified
- Wavy stratified
- Rolling wave
- Plug flow
- Slug flow
- Pseudo slug
- Annular flow

*Figure 1.4 Three-Phase Water-Oil-Gas Flow Patterns (Ai Hsin Lee, 1993)*
Figure 1.5 Flow Regime Map for a Water-CO₂ Flow System (Ai Hsin Lee, 1993)
to appear as rolling waves.

Plug or slug flow is seen to develop for liquid velocities greater than 0.35 m/s, at a constant gas flow. Plug flow consists of elongated gas bubbles that move through the liquid along the top of the pipe and is seen to exist at low gas velocities. At higher liquid and gas velocities slug flow develops. At these velocities the gas-liquid interface is wavy. The waves grow and eventually the wave height is sufficient to bridge the pipe and momentarily block the gas flow. When this occurs, the liquid in the bridge is accelerated to approximately the gas velocity. This fast moving liquid acts as a scoop, picks up the slow moving liquid ahead of it and accelerates it to the slug velocity. In this way the fast moving liquid builds its volume until it becomes a stable slug. As the slug moves along the pipeline, it sheds liquid from its back and this forms a stratified liquid film. This slug flow regime is similar to stratified flow but with the presence of intermittent highly aerated liquid slugs, which occupy the entire cross-section of the pipeline. Annular flow exists at very high gas velocities and consists of a thin liquid film along the circumference of the pipe with the gas flowing in the core.

Figure 1.6 is a typical flow regime map for water-oil-gas flows (Lee, 1993). The same flow regimes are observed as in a two phase water-gas flow. However, the transition between the regimes occurs at slightly different gas and liquid velocities. Three phase stratified flow is seen to occur at about 0.2 m/s liquid (mixture) velocity. In three-phase flow, the oil flows in between the gas and the water phases. Wavy stratified flow is seen to develop with a further increase in the gas velocity to about 1.5 m/s. Rolling waves are seen to appear as the liquid (mixture) and gas velocities are increased beyond 0.2 m/s
Figure 1.6 Flow Regime Map for 50% Water-50% Oil-Gas Flows (Ai Hsin Lee, 1993)
and 0.3 m/s, respectively. In each case, the oil layer still flows above the water layer with slight mixing at the interface. Further, it can be seen that both the wavy stratified and the rolling wave flow regimes are not observed below a liquid velocity of 0.1 m/s, contrary to what is seen in two phase water-gas flows. Plug and slug flows are seen at liquid velocities beyond 0.3 m/s. The gas is seen to flow as elongated bubbles along the top of the pipeline. Annular flow develops at high gas velocities wherein the CO₂ gas displaces the oil-water mixture, which flows as a thin film of liquid along the circumference of the pipe, and flows inside the core.

To understand the internal corrosion mechanisms, a knowledge of the flow regimes is essential. The mechanisms are dependent on the phase in contact with the pipe wall. Sea water in the presence of carbon dioxide is a major cause of corrosion in oil and gas pipelines, when the water is in contact with the pipe wall. Presence of water layers at the bottom of the pipeline can therefore cause extensive corrosion problems. It is therefore extremely important to be able to predict the flow regimes at different gas/liquid velocities to understand their effects on the corrosion mechanism.

Another phenomenon of concern is phase inversion, and it is important to industry as it can be used to set various flow parameters such as the velocity of the oil-water mixtures, the diameter of the pipeline etc. Study of the phase inversion phenomena is also important when using corrosion inhibitor chemicals. Inhibitors are usually oil or water soluble and need that phase to be the continuous phase for the inhibitor to work effectively.

Sharp increases in the pressure gradient have been observed by researchers in
small diameter pipelines and these have been attributed to the phase inversion phenomena. This study examines the occurrence of phase inversion by observing the pressure gradient in a large diameter pipeline. Two oils of considerably different viscosities are used and observations of the inversion at different oil-water concentrations and velocities are made.

Another factor this study examines is the type of flow regimes in oil-water and oil-water-gas flows in a large diameter horizontal pipeline, for both high and low viscosity oils. Flow regime studies determine the phase in contact with the pipe wall, the location of the phases and the degree of mixing during flow.

Thicknesses of the oil and water layers at different oil-water velocities and for different oil-water cuts were examined in the pipeline, for two and three-phase flows. A comparison has been made for high and low viscosity oils. From the observed thicknesses of the oil and water layers an effort has been made to determine the velocity of the two phases. The degree of mixing of the oil and water phases is also studied for the two oils at different oil-water velocities, in two-phase, oil-water flows, and at different input concentrations of the liquids.

This information can be used in the field for the selection of inhibitors or chemicals which coat the walls of the pipeline to prevent corrosion. This data will help in a more efficient use of the inhibitors and increase the length of operation of the pipeline.
In this chapter, the principles of two-phase flow will be presented, followed by a discussion of some of the most important works published in the field of oil-water and water-gas flows, relevant to this study. There is a conspicuous absence of work involving oil-water-gas flow in pipes.

2.1 Fundamentals of two-phase flow in pipes

Two-phase flow obeys the fundamental laws of fluid mechanics. However, due to the presence of momentum, heat and mass transfer between phases it is not possible to calculate the dynamic surface tension, viscosity and density of the two-phase mixture. Therefore, two-phase flow theories are usually developed from the concepts of single-phase flow. Using the laws of conservation of mass and momentum, the steady-state total pressure gradient for a single-phase fluid can be described as (Arirachakaran, 1983)

\[
\left( \frac{\partial p}{\partial L} \right)_{\text{TOTAL}} = \left( \frac{\partial p}{\partial L} \right)_{GR} + \left( \frac{\partial p}{\partial L} \right)_F + \left( \frac{\partial p}{\partial L} \right)_{ACC} \quad (2.1.1)
\]

where,

\[
\left( \frac{\partial p}{\partial L} \right)_{GR} = \text{pressure drop due to gravitational forces}
\]
\[
\frac{dp}{dL}_F = \text{pressure drop due to friction loss}
\]

\[
\frac{dp}{dL}_{\text{ACC}} = \text{pressure drop due to acceleration}
\]

The pressure losses due to gravitational forces and acceleration in compressible fluids are given by the following equations (Oglesby, 1979)

\[
\left(\frac{dp}{dL}\right)_{GR} = g \cdot \rho \cdot \sin \Theta \quad (2.1.2)
\]

\[
\left(\frac{dp}{dL}\right)_{\text{ACC}} = \rho \cdot \nu \cdot \left(\frac{dv}{dL}\right) \quad (2.1.3)
\]

where,

\[
\rho = \text{density of the liquid, Kg/m}^3
\]

\[
\nu = \text{average liquid velocity, m/s}
\]

\[
g = \text{acceleration due to gravity, m}^2/\text{s}
\]

For incompressible fluids, such as oil and water, in horizontal flow (where the pipe angle to the horizontal, \(\Theta\), is zero) the pressure gradient due to these terms can be neglected. Thus, for a single-phase, incompressible fluid in horizontal and steady state flow Equation 2.1 reduces to

\[
\left(\frac{dp}{dL}\right)_{\text{TOTAL}} = \left(\frac{dp}{dL}\right)_F \quad (2.1.4)
\]

The pressure gradient due to irreversible frictional pressure loss can be obtained from the Darcy-Weisbach equation (Malinowsky, 1975)
where,

\[ d = \text{diameter of the pipe, m} \]

\[ f_m = \text{the Moody friction factor} \]

The Moody friction factor, \( f_m \), is a function of the Reynold's number in laminar flow, and a function of both the pipe wall roughness and the Reynold's number in turbulent flow. For well developed turbulent flow the friction factor is a unique function of the Reynold's number. The Reynold's number is a dimensionless group given by

\[ N_{Re} = \frac{\rho \cdot \nu \cdot d}{\mu} \]  \hspace{1cm} (2.1.6)

The relationship between the Reynold's number, roughness of the pipe and the friction factor for laminar and turbulent flows is given in the Moody diagram. However, the standard relationships developed for laminar and turbulent flow friction factors can also be used.

For laminar flow,

\[ f = \frac{16}{N_{Re}} \]  \hspace{1cm} (2.1.7)

For turbulent flow (Blasius equation),

\[ f = 0.079 \cdot N_{Re}^{-0.25} \]  \hspace{1cm} (2.1.8)

When there is more than one phase present in the system, a further complication
occurs as the *insitu* volume fraction (the volume percentage of a phase inside the pipeline) of the mixture is not equal to the input volume fraction. Thus, it is common to assume that no slippage occurs between the two phases i.e. the input volume fraction is equal to the *insitu* volume fraction, as this in turn depends on the density and viscosity differences between the phases. The volume fractions in the system are calculated from the input flowrates of the respective phases.

The mixture properties are also affected by the different flow regimes. To predict pressure loss behavior, idealized flow patterns (homogeneous, stratified or annular) are commonly assumed.

Due to the effect of slippage, flow pattern and the mixture physical properties, the single-phase friction factor-Reynold's number relationship may not be valid for two-phase flow. As there are no instruments to measure or record these properties, no specific research on this topic has been reported for oil-water flows and as a result the single-phase relationship is often used.

The effective properties for the two-phase oil-water mixtures are often expressed with the help of certain mixing rules and definitions and are given below (Arirachakaran, 1983):

For the mixture velocity, \( V_m \) m/s,

\[
V_m = V_{so} + V_{sw}
\]  \hspace{1cm} (2.1.9)

where, \( V_{so} = \) superficial oil velocity, m/s

\( V_{sw} = \) superficial water velocity, m/s

For the mixture density, \( \rho_m \) Kg/m³,
\[ \rho_m = \rho_o \lambda_o + \rho_w \lambda_w \]  
(2.1.10)

where, \( \lambda_o \) = input oil fraction  
\( \lambda_w \) = input water fraction  
\( \rho_o \) = density of oil, Kg/m³  
\( \rho_w \) = density of water, Kg/m³

For the mixture viscosity, \( \mu_m \) cP,

\[ \mu_m = \mu_o \lambda_o + \mu_w \lambda_w \]  
(2.1.11)

where, \( \mu_o \) = viscosity of the oil, cP  
\( \mu_w \) = viscosity of water, cP

The input fractions ( \( \lambda_o \) and \( \lambda_w \) ) and are given by:

\[ \lambda_o = \frac{q_o}{q_o + q_w} = \frac{V_{so}}{V_{sm}} \]  
(2.1.12)

\[ \lambda_w = \frac{q_w}{q_o + q_w} = \frac{V_{sw}}{V_{sm}} \]  
(2.1.13)

where, \( q_o \) = input oil flowrate, m³/s  
\( q_w \) = input water flowrate, m³/s

Assuming a homogeneously dispersed oil-water flow pattern in horizontal pipes, the above relationships can be used to modify Equations 2.1.5 and 2.1.6 to give

\[ \frac{dp}{dL}_{\text{TOTAL}} = \frac{2 \cdot f_{m_p} \cdot \rho_m \cdot V_m^2}{d} \]  
(2.1.14)

The two-phase friction factor ( \( f_{m_p} \) ) can be estimated from Equation 2.1.7 or 2.1.8.
and using the two-phase Reynold's number (\( N_{Re_p} \)), given by

\[
N_{Re_p} = \frac{\rho_m \cdot V_m \cdot d}{\mu_m}
\]  
(2.1.15)

These equations can then be used to predict the pressure gradient for homogeneously dispersed oil-water flows using single-phase flow relationships. The mixture properties are extremely complex and further research is needed to modify the linear weighing rules used to predict the above properties.

For two-phase stratified flows, equations have been developed for gas-liquid and liquid-liquid flows in horizontal pipelines (Govier and Aziz, 1972). The schematic diagram of two-phase stratified flow is shown in Figure 2.1. The relationships between the velocities of the phases and the mixture have been given by

\[
Q_{\alpha} = V_{\alpha}A_{\alpha} = V_{sa}A
\]  
(2.1.16)

\[
Q_{\beta} = V_{\beta}A_{\beta} = V_{sp}A
\]  
(2.1.17)

\[
Q_{\alpha} + Q_{\beta} = V_{\alpha}A_{\alpha} + V_{\beta}A_{\beta} = (V_{sa} + V_{sp})A = V_mA
\]  
(2.1.18)

where,

\[
A = \text{pipe cross-sectional area, m}^2
\]

\[
Q_{\alpha} = \text{volumetric flow rate of the } \alpha \text{ phase, m}^3/s
\]

\[
Q_{\beta} = \text{volumetric flow rate of the } \beta \text{ phase, m}^3/s
\]

\[
A_{\alpha} = \text{cross-sectional area occupied by the } \alpha \text{ phase, m}^2
\]

\[
A_{\beta} = \text{cross-sectional area occupied by the } \beta \text{ phase, m}^2
\]
Figure 2.1 Schematic Diagram of Two-Phase Stratified Flow (Govier and Aziz, 1972)
\[ V_\alpha = \text{average velocity of the } \alpha \text{ phase, m/s} \]

\[ V_\beta = \text{average velocity of the } \beta \text{ phase, m/s} \]

\[ V_{sa} = \text{superficial velocity of the } \alpha \text{ phase, m/s} \]

\[ V_{sb} = \text{superficial velocity of the } \beta \text{ phase, m/s} \]

\[ V_M = \text{total superficial velocity of the mixture, m/s} \]

Referring to Figure 2.1 the force balances for the two phases can be written as

\[ A_\alpha \frac{dp}{dL} = \tau_{wa} c_\alpha + \tau_i w_i \quad (2.1.19) \]

\[ (A - A_\alpha) \frac{dp}{dL} = \tau_{wb} (\pi D - c_\alpha) - \tau_i w_i \quad (2.1.20) \]

where,

\[ \tau_{wa} = \text{shear stress at the wall for fluid } \alpha, \text{ N/m}^2 \]

\[ \tau_{wb} = \text{shear stress at the wall for fluid } \beta, \text{ N/m}^2 \]

\[ \tau_i = \text{shear stress at the interface, N/m}^2 \]

\[ c_\alpha = \text{portion of the pipe circumference in contact with the } \alpha \text{ phase, m} \]

\[ w_i = \text{width of the interface, m} \]

\[ D = \text{diameter of the pipeline, m} \]

On addition of Equations 2.1.19 and 2.1.20 the following realtionship is obtained
The wall shear stresses are evaluated approximately by applying the single-phase methods as shown

\[ A \frac{dp}{dL} = \tau_{w\alpha} \rho_{\alpha} + \tau_{w\beta} (\pi D - c) \]  

(2.1.21)

where the frictional factors for the \( \alpha \) and \( \beta \) phases (\( f_\alpha \) and \( f_\beta \)) are functions of the single phase Reynold's number for the corresponding phases and can be approximately calculated using the Blasius equation. The Reynold's number relationships for the two phases can be written as

\[ \tau_{w\alpha} = \frac{f_\alpha \rho_\alpha V_\alpha^2}{2} \]  

(2.1.22)

\[ \tau_{w\beta} = \frac{f_\beta \rho_\beta V_\beta^2}{2} \]  

(2.1.23)

\[ Re_\alpha = \frac{D_{E\alpha} V_\alpha \rho_\alpha}{\mu_\alpha} \]  

(2.1.24)

\[ Re_\beta = \frac{D_{E\beta} V_\beta \rho_\beta}{\mu_\beta} \]  

(2.1.25)

where,

- \( D_{E\alpha} \) = equivalent diameter of the cross-section occupied by the \( \alpha \) phase, m
- \( D_{E\beta} \) = equivalent diameter of the cross-section occupied by the \( \beta \) phase, m
- \( \mu_\alpha \) = viscosity of the \( \alpha \) phase, cP
- \( \mu_\beta \) = viscosity of the \( \beta \) phase, cP
In these relations $w_i, A_\alpha, A_\beta, c_\alpha, c_\beta, D_{Ea}$ and $D_{Eb}$ are all related geometrically to $h_\beta$ (the depth of the $\beta$ phase) and $D$. Therefore, if the average velocity of the two phases and the height of the $\beta$ phase is known, an approximation of the pressure gradient in the pipeline can be made. These equations assume an idealistic flow pattern where the interface is flat and smooth. However, mixing usually occurs at the interface of the two liquids which results in variations in the pressure drop inside the pipelines from the calculated values.

2.2 Previous work

Initially, research in the field of oil-water flow was focused on methods of transporting heavy crude oil in pipelines. Most methods involved systems in which different volumetric percentages of oil-water mixtures were injected into the pipelines. A demulsifying agent was used with water to aid the phase separation. Studies have also been conducted to predict and understand oil-water dispersion behaviours. A review of the related work done by researchers in this field follows.

Russel and Charles (1959) studied the phenomenon of pressure gradient reduction in oil pipelines due to the introduction of water. A general mathematical analysis was presented for both stratified flow between parallel plates and concentric flow in circular pipelines. They related the volumetric flow rates and the viscosities of the liquids to the pressure gradient. A comparison of the values of the pressure gradient obtained in the tests with the values calculated from their equations for the two systems was done. They concluded that oil-water flow in pipelines was intermediate between the stratified and concentric types.
Russel, et al. (1959) studied the flow of oil and water in a 8.5 m long pipeline with an inside diameter of 2 cm. The viscosity of the oil used was 18 cp and the specific gravity was 0.834, at 25 C. A theoretical analysis of the laminar flow of two immiscible fluids between wide parallel plates was used to correlate the data. The flow patterns observed were bubble, stratified and mixed flow. It was observed that, in the laminar region, *insitu* holdup is a function of the input concentrations of the liquids and the viscosity. In turbulent flow the superficial velocity was also seen to become a significant factor on the holdup.

Charles et al. (1961) studied the flow of equal density oil-water mixtures in a horizontal 2.6 cm pipe. Three oils of viscosities 6.29, 16.8 and 65 cP at 77 deg C were used. The input water concentrations varied from 10 to 90% and the total mixture velocities varied from 0.04 to 2.1 m/s. The input oil-water ratios were varied from 0.1 to 10. The flow patterns for increasing water fractions observed were: concentric-oil-in-water, oil-slugs-in-water, oil-bubbles-in-water and oil-drops-in-water. The flow patterns were observed to be independent of the oil viscosity, for the equal density mixture. In general, they also found that the *insitu* holdup tended to be higher than the no slip holdup, when the oil was in contact with the pipe wall. They also observed that the pressure gradient fell when water was added to the laminar oil stream upto a certain limit, beyond which adding water increased the pressure gradient, even above the gradient observed for oil alone.

Charles (1961) conducted experiments with crude oil and water in a 2.6 cm. inner diameter laboratory pipe and compared his results with data obtained from a 6.2 cm
inner diameter field pipe. The average viscosity of the oil used was approximately 700 cp with an average specific gravity of 0.95. He concluded that the drop in pressure gradient was maximum at 40-60% water concentration and was independent of the volumetric flowrate of oil.

Glass (1961) conducted experiments on the concentric flow of viscous oil in a water annulus in a 1.2 m long, 1 cm glass tube. Observations were made on the formation and stability of the concentric oil core-water annulus flow. Superficial oil velocities ranged from 0.06 to 1.3 m/s and the range of oil viscosity ranged from 10 to 30,000 centistokes. A model to predict the pressure drop for the annular flow from the superficial oil Reynold's number was developed and the relationship is given below:

\[
\frac{\Delta P_d}{\Delta P} = \frac{700}{N_{Re_{so}}}
\]  

(2.1.26)

where,

\( P_d \) = pressure gradient due to only oil in the system

\( P \) = pressure gradient with water as the annulus

\( N_{Re_{so}} \) = superficial oil Reynold's number

Guzhov et al. (1973) used a 21.7 cp and 0.896 specific gravity oil for experiments conducted in a 4 cm inner diameter horizontal pipe. The mixture velocity was varied from 0.2 to 1.7 m/s with the input water concentration varying from 0 to 100%. The pressure gradient was plotted against the oil concentration for increasing mixture velocities and is shown in Figure 2.2. Peaks were observed at around 60% water content for the mixture velocities. The peaks were attributed to phase inversion of the oil-water
Figure 2.2 Pressure Gradients vs. Water Concentration (Guzov, 1973)
system. Phase inversion, as defined earlier, is seen to occur when an increase in the concentration of the dispersed phase causes that phase to invert and become the continuous phase. The peaks due to phase inversion were not as sharp as the ones seen by researchers like Laflin and Oglesby (1976), Oglesby (1979) and Arirachakaran (1983). The following flow patterns were also observed for oil-water two-phase flows:

(a) stratified flow
(b) stratified flow with mixing at the interphase
(c) an oil in water dispersion
(d) Oil in water, water in oil and mixed emulsions

Malinowsky (1975) studied oil-water and air-oil-water horizontal flow through a 3.8 cm transparent pipe. At test conditions the oil had a viscosity of 4 cp and a specific gravity of 0.85. He observed that the pressure gradient was a function of the input water fraction (external phase) and increased significantly near the inversion point of the oil-water dispersion. He noted that the effective liquid viscosity of the oil-water mixture is largely dependent upon the viscosity of the external phase (and the commonly used weighting rules for the liquid viscosity were inadequate), thus causing a jump at the phase inversion point. Malinowsky also found that the area of contact with the pipe was not a direct function of the input concentrations due to the formation of a dispersion and also that there was little difference between the input and the in situ concentrations for both segregated and dispersed flow.

Laflin and Oglesby (1976) also studied oil-water and air-oil-water flow, using a No. 2 diesel oil with an average viscosity of 4.9 cp and a specific gravity of 0.83. The
input water concentrations varied from 30 to 80% and the superficial liquid velocities were in the range of 0.5 to 1.5 m/s. The pressure drop was recorded and was plotted against the input water fraction (Figure 2.3). It was observed that there was a sudden increase in the pressure drop when the water concentration was between 30% to 50%, for the range of velocities studied. The measured pressure drop was used to back calculate the effective liquid viscosity for both the oil-water and the air-oil-water systems. For the oil-water system they concluded that the maximum effective viscosity of the liquid occurred at the phase inversion point and that the effective liquid viscosity at the inversion point increased as the total mixture velocity increased (Figure 2.3). The effective liquid viscosity was also found to be proportional to the velocity of the mixture. Also, a flow pattern map was developed for oil-water flow and is shown in Figure 2.4. The nomenclature used is the same as for Figure 1.2. For the air-oil-water system the inversion point was seen to shift slightly to a higher water concentration when air was present at any concentration of the liquid mixture.

Arirachakaran (1983) used two oils SN-250 and 150-SB in his experiments with oil-water flow in a horizontal pipe of inner diameter 2.54 cm and length 6 m. The densities and the viscosities of water, SN-250 and 150-SB at 80 and 90 deg F are shown in Table 2.1. The data was taken for three mass flowrates: 45, 68 and 90 Kg/min which correspond to mixture velocities of 1.7 and 3 m/s. However, only 45 and 68 Kg/min flowrates were used for SB-150. The following observations were made from the gathered data: pressure drop was found to be a function of the mixture velocity, input water fraction, oil viscosity and the temperature. When water was the continuous phase,
Figure 2.3 Pressure Gradient vs. Input Water Fraction (Laflin and Oglesby, 1976)
Figure 2.4 Flow Pattern Map for Oil-Water Flows (Laflin and Oglesby, 1976)
Table 2.1 Density and Viscosity data for Water, SN-250 and 150-SB Oils (Arirachakaran, 1983)

<table>
<thead>
<tr>
<th>TEMP. (deg F)</th>
<th>WATER</th>
<th></th>
<th>SN-250 OIL</th>
<th></th>
<th>150 SB-OIL</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Density (Kg/m$^3$)</td>
<td>Viscosity (cp)</td>
<td>Density (Kg/m$^3$)</td>
<td>Viscosity (cp)</td>
<td>Density (Kg/m$^3$)</td>
<td>Viscosity (cp)</td>
</tr>
<tr>
<td>80</td>
<td>996.894</td>
<td>0.945</td>
<td>855.318</td>
<td>176.424</td>
<td>886.123</td>
<td>1445.56</td>
</tr>
<tr>
<td>90</td>
<td>995.26</td>
<td>0.842</td>
<td>846.027</td>
<td>131.353</td>
<td>879.203</td>
<td>987.578</td>
</tr>
</tbody>
</table>
temperature and oil viscosity had small effects on the pressure drop whereas when oil was the continuous phase, the temperature influenced the pressure drop due to the changes in the physical properties of the mixture (especially the viscosity of the oil). Pressure drop changed significantly at the phase inversion point and had the same magnitude as the single-phase oil pressure drop for the same flowing conditions. Mixture pressure drop was the same as the single-phase water pressure drop for the same flowing conditions and that slippage between phases played an important role when oil was the external phase. An increase in the mixture velocity increased the pressure drop. It was also observed that the apparent liquid viscosity decreased with an increase in temperature, the viscosity of the mixture approached the viscosity of the external phase and the apparent liquid viscosity reached its maximum value at the inversion point.

One of the most significant studies in the field of oil-water flows was conducted by Oglesby (1979). He used a mixture of SN-250 and Diesel oil No.2 and mixed the oils in order to obtain oils of different viscosities for his experiments conducted in a 3.8 cm inner diameter pipe. The velocity variation was from 0.6-3.6 m/s. The following phenomena were seen for the oil-water systems: There was a drastic change in the pressure drop at the inversion point and the magnitude of this change increased with increasing mixture velocity and oil viscosity, as seen in Figure 2.5 for No. 2 oil. The oil viscosity seemed to have a relatively small effect on the overall pressure loss, in the oil-in-water dispersion. It was also reported that the input water fraction at the inversion point decreased as the oil viscosity increased, the insitu holdups approached the no-slip holdups as the mixture velocity increased and that the flow patterns were a function of
Figure 2.5 Pressure Gradient vs. Input Water Fraction (Oglesby, 1979)
(Oil No. 2, Mixture Velocities = 1.0 and 1.5 m/s)
the mixture velocity and the input water fraction and also the oil viscosity, if the oil was the continuous phase.

Very little work has been done in the field of three phase flow. The relevant literature applicable to three-phase flow has been studied and a synopsis is being presented.

Lockhart and Martinelli (1949) worked on isothermal two phase, air-liquid flow in pipes varying the diameter from 0.15 cm to 2.6 cm. The liquids used were benzene, kerosene, water and various other oils. Pressure gradients were determined for turbulent-turbulent, viscous-turbulent, turbulent-viscous and viscous-viscous flow, of the gas and liquid phases, respectively.

Taitel and Dukler (1976) studied the effect of gas and liquid mass flowrates, properties of fluids, pipe diameter and the angle of inclination to the horizontal on the flow regime transitions and developed a theoretical model. They assumed the drag at the interface equal to the drag caused by the gas phase. The flow regimes considered were: intermittent (plug and slug), stratified smooth, stratified wavy, dispersed bubble and annular flow. For two-phase gas-liquid stratified flow, equations were developed to predict the cross-sectional area occupied by the two phases from the height of the liquid films. The equations developed are shown below:

\[
\frac{A_L}{D^2} = 0.25 \left[ \pi - \cos^{-1}(2h_L - 1) + (2h_L - 1)\sqrt{1 - (2h_L - 1)^2} \right] \tag{2.2.2}
\]
\[
\frac{A_g}{D^2} = 0.25 \left[ \cos^{-1}(2h_L - 1) + (2h_L - 1)\sqrt{1 - (2h_L - 1)^2} \right]
\] (2.2.3)

where,

- \( A_L \) = pipe cross-sectional area occupied by the liquid, \( m^2 \)
- \( A_g \) = pipe cross-sectional area occupied by the gas, \( m^2 \)
- \( D \) = diameter of the pipeline, \( m \)
- \( h_L \) = ratio of the height of the liquid layer to the diameter of the pipeline

Andritsos and Hanratty (1987) observed gas-liquid flows in horizontal pipelines. Experiments were conducted in pipelines with diameters of 2.52 cm and 9.53 cm. The oil viscosities used ranged from 1 to 80 cp. Experiments were performed to determine the drag at the gas-liquid interface and the drag of the wall on the liquid. The influence of the waves on the drag at the interface was taken into account and an improvement was made on a previous model predicted by Taitel and Dukler. It was found that the interfacial friction factor increased linearly with gas velocity, at gas velocities higher than needed to initiate waves. The proportionality constant was found to be insensitive to the pipe diameter.

Brauner and Maron (1992) formed a basis for constructing a general two-fluid flow pattern. The departure from the stratified flow regime (in the gas-liquid systems) to other flow patterns was studied. Mechanistic models were proposed for the transitional boundaries between these other flow patterns in liquid-liquid flow. A parametric study was made for a wide ranges of geometry and physical properties as encountered in liquid-liquid systems.
Hall and Hewitt (1993) proposed a methodology similar to the one suggested by Taitel and Dukler for two-phase gas liquid flows and applied it to two-phase oil-water flows. This was compared to an exact solution for flow between two infinitely wide flat plates and a numerical solution for flow in a circular pipe for laminar flow of both fluids. The exact solution showed a dependence on the ratio of the viscosity of the two phases for the liquid holdup.
CHAPTER 3

EXPERIMENTAL SETUP AND PROCEDURE

3.1 Description of the flow loop

3.1.1 Low Pressure System

Most of the experiments were conducted in a low pressure, horizontal water-oil-gas flow system. The schematic diagram of the flow loop is shown in Figure 3.1. The oil and water are stored in separate tanks and pumped into separate 7.5 cm internal diameter, PVC pipelines. The oil-water mixture is pumped using 5.2 kW centrifugal pumps and the maximum flow rate obtained is $11 \times 10^{-3}$ m$^3$/sec. A 11.2 kW gear pump is used for the high viscosity oil, Britol 50T, and the maximum flow rate produced is $6.3 \times 10^{-3}$ m$^3$/sec. The flow rate of each phase is controlled with the help of a gate valve and a bypass and is measured by individual orifice plates. The oil and water are combined and mixed with carbon dioxide gas in the mixing tank. The mixture is then passed through a 10.16 cm internal diameter, 10 m long plexiglass pipeline. The pipe discharges into a 2.65 m$^3$ separator. The gas is vented to the atmosphere. The oil and water return to their separate tanks.

A 2 m long plexiglass test section is installed in the pipeline and is shown in Figure 3.2. A sampling tube is used to withdraw liquid samples. The probe can be set at any point across a vertical diameter. The sample is passed into a one meter long, 1 cm inner diameter graduated tube. The tube is then turned to a vertical position and the phases are allowed to separate. The volumes of the oil, water and gas are measured.
Figure 3.1 Layout of the low pressure experimental system

A. Water-oil separator  
B. Water tank  
C. Oil tank  
D. Liquid-gas mixing tank  
E. Pump  
F. Orifice plate  
G. 7.5cm ID PVC pipe  
H. 10cm ID plexiglass pipe  
I. Gas feed  
J. Gas outlet  
K. By-pass valve
At high pressures, the flow is kept isokinetic by connecting a pressure vessel at the end of the graduated tube.

The pressure gradient is measured using a differential pressure transducer manufactured by Computer Instruments Corporation (series 7000 bubbler system with a 5525 differential pressure transducer). The system consists of an air supply tank, two gas flowmeters, a pressure indicator, a differential pressure transducer and a digital display unit. The transducer is connected to the two pressure tappings in the pipeline by flexible tubing. The gas flows from the tank into the tubing and is forced into the pipeline at the pressure tappings. The gas flow rate is measured by the flowmeters and the line pressure is displayed by the pressure indicator. A constant, low flow rate of the gas is maintained to avoid the development of any pressure gradients in the flexible tubing. The pressure transducer measures the difference in the backpressure generated by the air bubbles as they purge into the liquid at the two pressure tappings and a digital output is obtained. The tappings are 3 m apart and is pressure drop is displayed in inches of water. A minimum pressure gradient of 0.1 in. of water can be measured and the maximum limit can be varied. In the range of 1 in.-100 in. of water, the instrument is extremely sensitive and has a high accuracy of ± 0.25%. It can be used to detect small changes in the pressure drop in the pipeline and the much larger and sharp changes due to phase inversion. A VHS video camera was used to make visual observations. A water soluble dye was used to distinguish between the phases. The camera was placed at two positions, 4 m and 0.5 m, perpendicular to the pipeline. Two positions were chosen to get a picture of the type of flow from far and close to the test section.
The phase in contact with the bottom of the pipe was also determined using a conductance probe. This system consists of two metal probes, inserted into and aligned with the bottom of the pipeline, an ammeter and a bulb in series. A voltage is applied to the two probes and the flow of current in the circuit is monitored by observing the bulb. The bulb is seen to glow when water is in contact with the bottom of the pipeline and goes out when only oil is present. This is due to the fact that oil is a non-conductor of electricity whereas impure water provides a path for the current. The oil-water concentrations were varied and the bulb was observed to determine the phase in contact with the bottom of the pipeline.

3.1.2 High Pressure System

Some, three-phase flow, experiments were also conducted in the high pressure system. The schematic layout is shown in Figure 3.3. A known oil-water mixture is stored in the 1.2 m³ tank A. The mixture is circulated into a 7.6 cm inner diameter pipeline, E, with the help of a 5.2 kW centrifugal pump. Gate valve, C, on the bypass line and valve D are used to control the liquid flow rate. The flow rate is measured by a pressure transducer connected to an orifice plate, F. Liquid then enters the 10 m long, 10.16 cm inner diameter pipeline. The system is pressurized using gas from cylinders and the pressure is maintained with the help of a back pressure regulator K. Carbon dioxide gas is introduced into the pipeline at the point H. A pressure safety relief device, L, is also connected to tank A. The observations and measurements are made in the test section which is identical to the one in the low pressure system and described in the previous
Figure 3.3. Layout of the high pressure experimental system

A. Liquid Tank
B. Liquid Recycle
C. Valve on Liquid Feed
D. Valve on Liquid Feed
E. Orifice plate, transducer
F. Flow Height Control Gate
G. Pressure Gauges & Back Pressure Regulator
H. Carbon Dioxide Feed Line
I. Test Section - 4" Stainless Steel Pipe
J. 4" Stainless Steel Section
K. Safety Valve
L. Heater
M. Pump
3.2 Procedure and Test Matrix

The liquids are pumped with the help of the centrifugal or the gear pumps into the pipeline. Gas is also introduced into the pipeline from storage tanks, if required. The flow rate of the liquids and carbon dioxide gas is set and the flow is allowed to stabilize. The bubbler system is then turned on and the air from the tank is introduced into the test section through the flexible tubing connected to the pressure taps. The experiments are performed under full pipe, stratified three-phase and slug flow conditions. Videos of the flow regime are taken. Samples are withdrawn from the test section to determine the composition of the mixture at different heights along the diameter of the pipeline. These liquid fractions are used to determine the phase present at a particular vertical height from the bottom of the pipe. This data along with the visual observations are used to determine the thickness of the water layer. The pressure drop data is also collected from the digital display in the bubbler system. These measurements are made at different oil/water compositions for each mixture flow rate by varying the flow rates of the two phases. The flow rate of the gas is also varied at each liquid composition.

Numerous experiments were performed to study the phase inversion phenomena in two-phase, full pipe flow. Liquid film heights and holdup measurements, in two-phase full pipe flow and three-phase stratified flow, have been recorded. The thickness of the oil and water films between slugs were also studied for Britol 50T. The type and properties of the oils used are shown in Table 3.1. The test matrix is given below. The
effect of change in liquid percentage, pressure, gas velocity and the flow regime is systematically studied.

Study of the Phase Inversion Phenomena (LVT 200 and Britol 50T)

Two-Phase, Full Pipe Flow Conditions

<table>
<thead>
<tr>
<th>Parameters varied</th>
<th>Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil-Water Percentage</td>
<td>0% oil-100% water to 100% oil-0% water</td>
</tr>
<tr>
<td>Mixture Velocity</td>
<td>LVT 200: 0.4, 0.6, 0.8, 1.0, 1.2 and 1.4 m/s</td>
</tr>
<tr>
<td></td>
<td>Britol 50T: 0.4, 0.5, 0.6, 0.7 and 0.8 m/s</td>
</tr>
</tbody>
</table>

Study of Film Heights (50% Water - 50% LVT 200 mixture)

Three-Phase, Stratified Flow

<table>
<thead>
<tr>
<th>Parameters to be varied</th>
<th>Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure</td>
<td>atmospheric pressure, $1.7 \times 10^5$ N/m²</td>
</tr>
<tr>
<td>Total Liquid Velocity</td>
<td>0.15, 0.25 and 0.32 m/s</td>
</tr>
<tr>
<td>Gas Velocity</td>
<td>1.5, 3.0 and 4.5 m/s</td>
</tr>
</tbody>
</table>
Study of Film Heights between Slugs ( Britol 50T )

Three-Phase, Slug Flow

Parameters to be varied : Conditions

Oil-Water Percentage : 20% water- 80% oil
                      40% water- 60% oil
                      60% water- 40% oil
                      80% water- 20% oil

Total Liquid Velocity : 0.2, 0.4, 0.6 and 0.8 m/s

Gas Velocity : 0.8, 2.3, 3.7 and 4.9 m/s

<table>
<thead>
<tr>
<th>Property</th>
<th>LVT 200</th>
<th>Britol 50T</th>
</tr>
</thead>
<tbody>
<tr>
<td>Viscosity (cP) at 40C</td>
<td>2</td>
<td>100</td>
</tr>
<tr>
<td>Density (Kg/m³) at 40C</td>
<td>800</td>
<td>848</td>
</tr>
<tr>
<td>Color, Odor</td>
<td>Colorless, Odorless</td>
<td>Grey, Odorless</td>
</tr>
</tbody>
</table>

Table 3.1 Properties of the oils LVT 200 and Britol 50T
CHAPTER 4

EXPERIMENTAL RESULTS AND DISCUSSION

4.1 Two-phase oil-water, full pipe flows

4.1.1 Flow patterns for oil-water flows

The flow patterns are observed visually in the pipeline with the help of the VHS video camera. The flow regimes observed for oil-water flow have been divided into three categories and the photographs of the flows are shown in Figure 4.1. All the three flow regimes (bubble, semi-segregated and semi-mixed) were observed in the case of a LVT 200-water mixture whereas the Britol 50T-water mixture was always seen to be in semi-segregated flow. The three types of flow are discussed below.

**Bubble flow.** This regime is observed for the low viscosity LVT 200 when the mixture velocity is in the range of 0.4 - 0.6 m/s and the input oil percentage is less than 10%. Water occupies almost the entire cross-section of the pipeline. Oil is seen to flow in the form of bubbles at the top of the pipe. The oil layer is not continuous and the water is seen to wet the entire circumference of the pipe.

**Semi-segregated flow.** This flow regime is observed when the input oil concentration is increased above 20%, in the mixture velocity range of 0.4 - 0.8 m/s. The flow regime is described in Section 1.1. The cross-section occupied by each layer is dependent on the input fractions of the two phases. The oil-water interface consists of oil droplets in the water phase and the water droplets in the oil phase. For the LVT
Figure 4.1 Photographs of the Flow Regimes Observed

(a) Bubble

(b) Semi-segregated

(c) Semi-mixed
200-water flows, it was noticed, for all velocities, that more of the water dispersed into the oil but there was a predominantly 'free' water phase at the bottom of the pipe. In case of the Britol-water mixture it was observed that for input water concentrations less than 30%, the 'free' water phase was not present. However, when the water percentage was raised to and above 40%, a more conspicuous water phase was seen at the bottom of the pipe. The oil-water interface is seen to become increasingly wavy in nature as the mixture flow rate is gradually increased.

**Semi-mixed flow.** For LVT 200-water mixtures, it is observed that for an increase in the mixture flow rate beyond 0.8 m/s and for input water percentages greater than 50%, the waves at the interface become indistinguishable and an oil-water dispersion occupies a large portion of the flow around the interface. Water is seen to penetrate the oil layer and is present at the top of the pipeline. As the mixture velocity is progressively increased from 1.0 m/s to 1.4 m/s, the mixing zone is seen to occupy larger cross-sectional areas of the pipeline, indicated by larger quantities of water encountered at the top of the pipe. The thickness of the "free" water phase at the bottom of the pipeline is also seen to decrease, due to more intimate mixing of the oil and water phases. This results in larger cross-sections of the pipeline being occupied by the oil-water dispersion. In this range of mixture velocities and for water percentages greater than 50%, the mixing zone occupies more than half of the pipe cross-section. The oil-water mixture in the pipeline is almost, but not completely, homogeneous in nature at a mixture velocity of 1.4 m/s when the input water percentage is 80%. There is a distinct water layer at the bottom of the pipeline even at this velocity. A detailed discussion of the oil-water mixing phenomena
is presented in Section 4.1.3.

The flow pattern maps developed by Oglesby (1979) and a modification of the Malinovsky map (1975), presented by Laflin and Oglesby (1976), have been shown in Chapters 1 and 2. The nomenclature used is the same as that used by Oglesby and is described in Chapter 1. It is seen by reviewing the available literature that only Oglesby observed all the flow regimes from segregated to homogeneous, as described earlier in Chapter 1. Laflin and Oglesby did not observe the concentric and the slug flow regimes and most of the oil dominant flow regimes. This compares well with the flow regimes seen in this study. The semi-segregated flow regime has been reported to exist till about 0.3 to 0.5 m/s (Figures 1.2 and 2.3). Laflin and Oglesby observed that the water dominant semi-mixed and mixed flows occur above a mixture velocity of about 0.5 m/s at 50% input water concentration and a further increase in the velocity to 0.8 m/s changes the flow type to semi-dispersed. Above 1 m/s the flow was seen to be fully dispersed or homogeneous in nature. A similar variation is observed in the present study. However, the previous studies were conducted in smaller diameter pipelines (Chapter 2) and therefore, the velocities required to obtain these flows are higher due to the larger diameter of the pipeline used.

4.1.2 Pressure Gradient

For the low viscosity oil, LVT-200, the variation of pressure gradient for velocities between 0.4 m/s and 1.4 m/s is shown in Figure 4.2. For velocities of 0.4 and 0.6 m/s, it is seen that no large changes in the pressure gradient are observed with an increase
Figure 4.2 Variation of pressure drop with input water percentage for LVT 200 oil
in the water cut. It was noticed that in this range of velocities, the oil-water mixture behaves as a stratified flow with mixing of the oil and water occurring only at the oil-water interface. For mixture velocities in the range from 0.8 to 1.4 m/s, the pressure drop is affected by an increase in the water percentage. The effect is more pronounced as the mixture velocity is increased. For a superficial mixture velocity of 0.8 m/s, the pressure gradient with only oil in the system is 60 N/m$^3$. This is in agreement with the calculated value of 60.5 N/m$^3$ for LVT 200, using the single-phase relationships described in Section 2.1. As the input concentration of water is increased, the pressure gradient does not vary drastically. However, it is seen that there is a gradual increase in the pressure gradient between the input water concentrations of 40 to 60% from about 65 N/m$^3$ to 80 N/m$^3$. It then drops down again to 65 N/m$^3$ when the water cut is increased to 70%. Further increase in the water percentage to 100% results in a pressure gradient of 60 N/m$^3$ which is in agreement of the calculated value of 60.1N/m$^3$. As the mixture velocity is increased, the variation in the pressure gradient becomes more apparent with an increase in the water cut.

For a mixture velocity of 1.4 m/s, the pressure gradient is in close agreement with the calculated value of 161.1 N/m$^3$ for 100% LVT 200. As the input water fraction is increased from 20 to 50% the pressure gradient increases significantly from about 175 N/m$^3$ to 225 N/m$^3$. An increase in the water cut beyond 50% results in a gradual decrease in the pressure gradient to about 170 N/m$^3$ for 100% water.

It was observed that at the range of 0.8 to 1.4 m/s mixture velocity and at low water percentage (below 40%) there was an oil-water mixture at the interface with only
oil at the top and water at the bottom, as in the semi-segregated flow regime. An increase in the water concentration caused the oil-water flow to become increasingly well mixed and the flow pattern changed from semi-segregated to semi-mixed (with a "free" water phase). This change in flow regime occurred at lower water percentages with increasing mixture velocities (between 60 to 80% input water fraction for a mixture velocity of 0.8 m/s and 20 and 40% for a velocity of 1.4 m/s) and resulted in the water touching the top of the pipe and becoming the continuous phase. A detailed explanation of this mixing phenomena is given in Section 4.1.3. From the observations made, the changes in the pressure gradient can be attributed to the water touching the top of the pipe and the formation of an oil in water dispersion. As a result of the water becoming the continuous phase, the flow dynamics in the pipeline are altered and this can be observed as a variation in the pressure gradient. This is similar to the pressure variations seen by Guzov (1973) and therefore this change in flow regime, with water flowing as the continuous phase, can be termed as the phase inversion phenomena. The inversion is seen to take place between 50% and 70% water percentage at lower mixture velocities of around 1 m/s and between 30% and 50% for higher velocities. The pressure drop before and after the inversion point is seen to be close to that due to only oil and only water in the system, respectively.

Guzov et al. (1973) showed a similar variation in the pressure gradients for oil-water dispersions. The pressure gradients recorded were shown in Figure 2.2. Laflin and Oglesby (1976) and Oglesby (1979) also observed phase inversion in the semi-mixed flow regime (shown by the darkened lines in Figures 1.2 and 2.4). They also reported
that the peaks due to the pressure loss shifted to lower water concentrations with an increase in the mixture velocity. All the studies mentioned above and those conducted by Arirachakaran (1983) and Charles (1961) showed that the pressure drop approached the value due to only oil and only water in the system before and after the inversion point (when the dispersion changes from oil continuous to water continuous), respectively. Malinowsky (1975), Laflin and Oglesby (1976), Oglesby (1979) and Arirachakaran (1983) showed that the viscosity of the oil has a significant effect on the pressure drop, with the higher viscosity oils giving a greater pressure drop at the inversion point.

In an effort to observe more distinct changes in the pressure gradient, experiments were undertaken using Brit0150T, an oil with viscosity of 100 cp at 40 C. The range of liquid velocities studied were 0.4 m/s to 0.8 m/s. Velocities greater than 0.8 m/s could not be readily obtained due to high viscosity and pump capacity.

It is seen from Figure 4.3, that the pressure gradient decreases as the water concentration is increased. For a velocity of 0.8 m/s, the pressure gradient is has a maximum of approximately 275 N/m³ for oil flowing alone in the pipeline. As the percentage of water in the system is increased from 20 to 40%, the pressure gradient decreases sharply to 270 N/m³ and then 140 N/m³, respectively. After this, there is a gradual decrease in the pressure gradient to about 70 N/m³ for 100% water. The single-phase rules were used to calculate the pressure gradients for oil and water in the pipeline. The calculated values were seen to match the observed values, giving room for experimental error. For a mixture velocity of 0.8 m/s the calculated pressure loss for 100% oil is 256 N/m³ and for 100% water it is 60.13 N/m³. The same trend is observed
Figure 4.3 Variation of pressure drop with input water percentage for BRITOL 50T.
for all the liquid velocities. The pressure gradient is also seen to decrease with a decrease in the total mixture velocity.

No distinct peaks in the pressure drop data are observed for Britol in this velocity range and therefore, there is no indication of inversion. The decrease in the pressure drop can be attributed to the appearance of a pure water phase at the bottom of the pipeline. As the input water concentration is increased, the amount of oil in contact with the bottom of the pipe decreases. The resulting lower value of the pressure gradient can be attributed to the disappearance of the higher viscosity oil from the bottom of the pipe. A thin layer of water is seen to flow at the bottom of the pipe and a small amount of the water phase penetrates the oil phase. As a result of the reduced cross-sectional area of flow, the water is seen to flow extremely fast along the bottom of the pipeline. Water is not seen to disperse as intimately in the Britol as it is in the LVT 200 oil. This can be the effect of the mixture properties like viscosity, surface tension, and density etc. A detailed explanation of the mixing phenomena is given in Section 4.1.3.

In order to further study the cause of the sudden decrease in the pressure drop, the input percentage of Britol required for it to touch the bottom of the pipe was also found. This was accomplished by using a conductance probe at the bottom of the pipeline and the results are shown in Figure 4.4. For a velocity range of 0.4 to 0.8 m/s, Britol is seen to come in contact with the bottom of the pipe when its input concentrationin ranges between 60% to 80%. The bulb in series with the conductance probes started flickering when the input oil percentage was between 60% to 80%, suggesting that the non-conducting oil phase was in contact with the bottom of the pipe. Therefore, above a range
Figure 4.4 Percentage of Britol when it touches the bottom of the pipe
of approximately 20 to 40% input water concentration, water becomes the only phase in contact with the bottom of the pipe leading to the sharper decreases in the pressure gradients seen in Figure 4.3. As the concentration of water is increased beyond 40%, the thickness of the water layer increases suggesting that the velocity of the water phase decreases. This can be seen later in Section 4.1.4.

Pressure gradients calculated for two-phase flows of both the oils and water at different concentrations using the single-phase rules described in chapter 2, are shown in Table 4.1. The calculated values of the pressure gradient match with the observed values but do not show the sudden peaks in the range of 20% to 60% water for the LVT 200 oil-water mixtures. For example, at a mixture velocity of 1.0 m/s and at all oil-water concentrations, the calculated pressure gradient is about 90 N/m² (Appendix A). Due to the negligible difference in the viscosities and a small difference in the densities of the oil and water, the calculated pressure gradients for different oil-water concentrations do not vary significantly. Similar pressure gradients are observed in the system for water percentages below 40% and greater than 70%. The change in the pressure gradient between 40% and 70% cannot be determined by the single-phase equations. The change in the mixture characteristics as a result of the inversion phenomena are not shown by the pressure gradients calculated using the single-phase, weighting rule relationships.

For a Britol-water mixture a comparison of the values in Table 4.2 and the ones plotted in Figure 4.3 shows that the calculated pressure gradients are lower than the values recorded, for water concentrations below 40%. For water percentages above 40%, the calculated and observed pressure gradients are seen to be within the ranges
<table>
<thead>
<tr>
<th>Total Mixture Velocity (m/s)</th>
<th>80% input water concentration (N/m³)</th>
<th>70% input water concentration (N/m³)</th>
<th>60% input water concentration (N/m³)</th>
<th>50% input water concentration (N/m³)</th>
<th>40% input water concentration (N/m³)</th>
<th>30% input water concentration (N/m³)</th>
<th>20% input water concentration (N/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.4</td>
<td>18.2</td>
<td>18.2</td>
<td>18.3</td>
<td>18.3</td>
<td>18.3</td>
<td>18.2</td>
<td>18.2</td>
</tr>
<tr>
<td>0.6</td>
<td>36.9</td>
<td>37.1</td>
<td>37.1</td>
<td>37.2</td>
<td>37.1</td>
<td>37.1</td>
<td>36.9</td>
</tr>
<tr>
<td>0.8</td>
<td>61.0</td>
<td>61.3</td>
<td>61.4</td>
<td>61.4</td>
<td>61.1</td>
<td>61.3</td>
<td>61.1</td>
</tr>
<tr>
<td>1.0</td>
<td>90.2</td>
<td>90.6</td>
<td>90.8</td>
<td>90.8</td>
<td>90.6</td>
<td>90.6</td>
<td>90.3</td>
</tr>
<tr>
<td>1.2</td>
<td>124.1</td>
<td>124.6</td>
<td>124.9</td>
<td>125.0</td>
<td>124.9</td>
<td>124.7</td>
<td>124.2</td>
</tr>
<tr>
<td>1.4</td>
<td>162.5</td>
<td>163.2</td>
<td>163.6</td>
<td>163.7</td>
<td>163.6</td>
<td>163.3</td>
<td>162.7</td>
</tr>
</tbody>
</table>

Table 4.1 Calculated pressure gradients for LVT 200 oil and water at different concentrations using the single-phase relationships
Table 4.2 Calculated pressure gradients for Britol 50T oil and water at different concentrations using the single-phase relationships

<table>
<thead>
<tr>
<th>Total Mixture Velocity (m/s)</th>
<th>80% input water concentration (N/m³)</th>
<th>70% input water concentration (N/m³)</th>
<th>60% input water concentration (N/m³)</th>
<th>50% input water concentration (N/m³)</th>
<th>40% input water concentration (N/m³)</th>
<th>30% input water concentration (N/m³)</th>
<th>20% input water concentration (N/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.4</td>
<td>37.3</td>
<td>39.3</td>
<td>52.0</td>
<td>64.6</td>
<td>77.3</td>
<td>90.0</td>
<td>102.7</td>
</tr>
<tr>
<td>0.5</td>
<td>55.1</td>
<td>60.0</td>
<td>65.0</td>
<td>80.8</td>
<td>96.6</td>
<td>112.5</td>
<td>128.3</td>
</tr>
<tr>
<td>0.6</td>
<td>75.8</td>
<td>82.6</td>
<td>78.0</td>
<td>97.0</td>
<td>116.0</td>
<td>135.0</td>
<td>154.0</td>
</tr>
<tr>
<td>0.7</td>
<td>99.3</td>
<td>108.1</td>
<td>114.6</td>
<td>113.1</td>
<td>135.3</td>
<td>157.5</td>
<td>179.7</td>
</tr>
<tr>
<td>0.8</td>
<td>125.5</td>
<td>136.7</td>
<td>144.8</td>
<td>129.3</td>
<td>154.6</td>
<td>180.0</td>
<td>205.3</td>
</tr>
</tbody>
</table>
of experimental error. The calculated pressure gradient for a 20% water-80% oil mixture flowing at a velocity of 0.7 m/s is 179.7 N/m³ and the observed value is 240 N/m³. As the water percentage is increased to 30%, the calculated and experimental values are 157.5 N/m³ and 175 N/m³. As the water concentration is increased to 50% the calculated and observed values of the pressure gradient are 113.1 N/m³ and 120 N/m³. These values at a 80% water cut are 99.3 N/m³ and 90 N/m³. The calculated pressure gradients are within the ranges of experimental error in some cases and considerably different to the observed values, in others. Calculation of the pressure gradients using the weighting rules is therefore not a very reliable method. Also, the calculated pressure gradients are unable to show the transition point at which the oil no longer touches the bottom of the pipeline.

The inability of the calculated pressure gradients to predict this sharp drop in pressure and the peaks (as seen in the LVT 200-water mixtures) shows the ineffectiveness of the mixing rules. These weighting rules therefore, cannot be used to predict the changes in two-phase, oil-water flow characteristics. It is apparent that these equations do not take into account the mixture properties and their variations with the type of flow. A detailed study of the dispersion density, viscosity, surface tension and the distribution of the phases in the pipelines is required and better correlations have to be developed to predict insitu mixture properties.

4.1.3 Water film heights

A study has been conducted on the oil-water flow mechanisms. It is found that the oil and water phases were not completely mixed and a semi-segregated flow regime
existed in the pipeline for the velocity ranges: 0.4 m/s to 0.6 m/s, for LVT 200-water mixtures, and 0.4 m/s to 0.8 m/s for Britol 50T.

Liquid fractions are taken along the vertical diameter of the pipeline with the help of a sampling/pitot tube inserted into the test section. The experimental error was approximately +/- 5%. Videos of the flow were also taken for each condition to determine the water film heights as seen in Figure 4.5. The water samples were withdrawn at different heights from the bottom of the pipe and the ratio of the thickness of the water layer from the bottom of the pipe to the diameter of the pipeline, h/D, is plotted against the water percentage as shown in Figures 4.6 through 4.11.

Figures 4.6, 4.7 and 4.8 show the results for LVT 200 oil at liquid velocities of 0.4, 0.5, and 0.6 m/s. It is seen that for a mixture velocity of 0.4 m/s and at a composition of 80% water and 20% oil, LVT 200, only small amounts of water are encountered above an h/D of 0.8 (2 cm from the top of the pipe). As the sampling tube is moved to a lower value of 0.7, the percentage of water increases to about 40%. There is only a small change in the percentage of water between the heights of 0.7 and 0.5. This signifies the presence of a relatively well mixed oil-water interface. Below 0.5, there is again a significant increase in the water percentage. Water alone was seen to exist below an h/D of 0.4.

For an input concentration of 20% water and 80% oil it is observed that the height above which small amounts of water are encountered falls to a much lower value of 0.4. As the tube is moved down to a height of about 0.38 the water percentage increases to about 30%. Between the heights of 0.38 and 0.2, there is a gradual increase in the water
Figure 4.5 Sample Collection with a Pitot Tube in the Pipeline
Figure 4.6 Variation of water percentage with vertical position
(Oil: LVT-200; Total Velocity=0.4 m/s)
Figure 4.7 Variation of water percentage with vertical position (Oil: LVT-200; Total Velocity=0.5 m/s)
Figure 4.8 Variation of water percentage with vertical position
(Oil: LVT-200; Total Velocity=0.6 m/s)
percentage from 30% to about 50%. This depicts layers in which the oil and water mixture is similar to the flow shown in Figure 1.1(a), flowregime type B. Only water is seen to exist below a h/D of about 0.1.

Similar trends are seen for all the interim oil-water concentrations. The thickness of the mixing layer increases with an increase in the percentage of water in the mixture. The height below which only water is encountered in the pipeline also increases with an increase in the input water percentage. As the LVT 200-water mixture velocity is increased to 0.5 m/s and 0.6 m/s, Figures 4.7 and 4.8 indicate that the thickness of the water layer increases for each input water concentration i.e. the height below which only water is found in the pipeline increases with an increase in the mixture velocity, for the same oil-water ratios. Similarly, the height to which the water penetrates into the oil phase for each oil-water concentration also increases with an increase in the mixture velocity. It can also be seen that the variation of the composition of the oil-water mixture, in the mixing layer, becomes comparatively less as the velocity is increased. This is more apparent at higher water concentrations. It is observed that a distinct water phase is encountered at the bottom of the pipe even at the lowest water cuts for the velocity range of 0.4 - 0.6 m/s.

For the mixture velocity range of 0.8 - 1.4 m/s, the degree of mixing is seen to increase considerably. This can be seen in Figures 4.9 to 4.12. At a velocity of 0.8 m/s ( Figure 4.9 ), the area occupied by the oil-water mixing zone is seen to increase significantly compared to a velocity of 0.6 m/s. However, due to this increase in mixing of the oil-water phases, the heights below which only water is encountered in the pipeline
Figure 4.9 Variation of water percentage with vertical position
(Oil: LVT 200; Total Superficial Velocity=0.8 m/s)
Figure 4.10 Variation of water percentage with vertical position
(Oil: LVT 208; Total Superficial Velocity=1.0 m/s)
Figure 4.11 Variation of water percentage with vertical position
(Oil: LVT 200; Total Superficial Velocity=1.2 m/s)
are seen to decrease for all oil-water concentrations. For an 80% input water fraction, about 23% of water is encountered at a h/D of about 0.95. As the pitot tube is moved down the pipe, it is observed that the water concentration was in the range of 50% between a h/D of 0.90 and 0.45. This signifies that the oil and water mixture is fairly well mixed and homogeneous in that region. Below a h/D of 0.45 the percentage of water encountered increases rapidly to the bottom of the pipe. The water constitutes about 70% of the mixture at a h/D of about 0.4 and only water is encountered below a h/D of about 0.37. This implies that even though the water penetrates readily into the oil phase and reaches the top of the pipe, there is still a water layer at the bottom of the pipe. The height at which water is first encountered in the pipeline, the thickness of the water layer and the relative homogeneity of the mixing zone decreases with a decrease in the water concentration. This can be seen for input water concentrations of 60%, 40% and 20%.

At an input concentration of 20% water, water is encountered in small quantities above a h/D of 0.75. There is a gradual increase in the water concentration from 25% to about 70% as the height decreases from 0.7 to 0.3. From 0.3 to about 0.1, h/D, the water concentration increases rapidly to 100%. The gradual increase in the water concentration from a h/D of 0.7 to 0.3 suggests that the oil-water mixing zone is not homogeneous. It can also be seen that as the input water percentage is less, more of the oil is present near the bottom of the pipe and therefore a relatively thinner water layer exists at the bottom of the pipe.

For mixture velocities of 1.0 and 1.2 m/s it can be observed, from Figures 4.10 and 4.11, that for input water concentrations greater than 20% the water penetrates further
into the oil phase and touches the top of the pipe. The oil also penetrates into the water layer but is unable to touch the bottom of the pipe. With an increase in the mixture velocity the thickness of the water layer at the bottom of the pipeline decreases due to the greater penetration of the oil, for all input oil-water concentrations. As seen for the mixture velocity of 0.8 m/s, an increase in the water concentration results in a relatively more homogeneous mixing zone for both the velocities. A comparison between the two figures shows that the oil-water homogeneous zone becomes larger with an increase in the mixture velocity, for all oil-water concentrations.

The oil-water mixture is seen to be relatively well mixed at a mixture velocity of 1.4 m/s (Figure 4.12). The water is seen to come in contact with the top of the pipe for all oil-water concentrations. A small amount of oil is also seen at the bottom of the pipe for input water concentrations of 20 and 40%. However, the amount of water encountered at the top of the pipe is higher compared to the amount of oil at the bottom. The homogeneous zone is seen to extend from a h/D of 0.9 to about 0.2, for an input water concentration of 80% and is seen to occupy even more of the pipe diameter. For an input water concentration of 20%, the mixing layer is seen to become more homogeneous, compared to a velocity of 1.2 m/s.

Similar studies were conducted for Britol 50T-water mixtures at total superficial velocities ranging from 0.4 to 0.8 m/s and the results are shown in Figures 4.13, 4.14 and 4.15. Figure 4.13 shows the variation of water percentage with the vertical position for different input oil-water concentrations at a total velocity of 0.4 m/s. It is seen that for a 80% water input, water is only noticed below an h/D of approximately 0.55. This is at
Figure 4.13 Variation of water percentage with vertical position
(Oil: Britol 50T; Total Superficial velocity=0.4 m/s)
Figure 4.14 Variation of water percentage with vertical position
(Oil: Britol 50T; Total superficial velocity=0.6 m/s)
Figure 4.15 Variation of water percentage with vertical position (Oil: Britol 50T; Total superficial velocity=0.8 m/s)
a much lower height than that of LVT 200 at the same conditions. Water alone is found below an h/D of 0.2. The height at which water is first encountered decreases with a decrease in the input water percentage and the thickness of the water layer increases with an increase in the input water percentage, as seen for LVT 200. Similar trends are seen for mixture velocities of 0.6 and 0.8 m/s (Figures 4.14 and 4.15). It was observed that in this velocity range the oil-water mixture was in the semi-segregated flow regime. As the total liquid velocity is increased, the thickness of the water layer and the height at which water is first encountered in the pipeline increases at each water cut.

From the above graphs and visual observations water layer thicknesses have been plotted for both the oil-water mixtures only in the semi-segregated flow regime and these are shown in Figures 4.16 and 4.17. It has been seen that, for LVT 200, the oil-water mixture is in the semi-segregated flow regime for the velocity range of 0.4 - 0.6 m/s, after which it gets relatively well mixed in the range of mixture velocities of 0.8 to 1.4 m/s. The thickness of the water layer is estimated to be the height from the bottom of the pipeline at which the water percentage is approximately 50%. This estimate is made from the water percentages collected along the vertical diameter of the pipeline and an experimental error of about +/-10% can be incorporated. The height below which only water is found in the pipeline increases with an increase in velocity and the input water concentration, in the semi-segregated flow regime. It can be seen that, in this flow regime, the water film is much thicker for the lower viscosity oil. It can also be observed that the film heights are more dependent on the concentration of water phase, at each mixture velocity. For any given input water percentage, in the semi-segregated flow regime,
Figure 4.16 Variation of the water film height vs. Total superficial velocity for LVT-200 oil
Figure 4.17 Variation of the water film height vs. Total superficial velocity for Britol 50T oil
the water film thicknesses increase with an increase in the liquid velocity for both the oils.

For LVT 200, as the flow pattern changed from semi-segregated to well mixed, it has already been seen from Figures 4.9 to 4.12 that the degree of mixing at the interface increased and the oil-water mixture occupied a large portion of the pipe diameter. The thickness of the oil-water interface is seen to increase with an increase in the water concentration, for all mixture velocities in this range. As the oil-water mixtures occupy most of the pipe diameter at large input water concentrations, it is impossible to predict the thickness of the water layer. However, it was seen that there was a distinct water layer at the bottom of the pipeline even in this range of velocities, suggesting that the oil water mixture was not homogeneous in nature.

4.1.4 Liquid Holdup

It was observed that when Britol 50T was introduced into the system, it occupied a much greater cross-sectional area of the pipe than the LVT 200 at the same flowing conditions. From the liquid fractions data the *insitu* water holdups, i.e. fractions of pipe cross-section occupied by the liquid have been determined.

Figures 4.18 and 4.19 show the ratio of *insitu* to input water holdup for LVT 200 and Britol at water cuts ranging from 20 to 80% in the semi-segregated flow-regime. A comparison in the mixed flow-regime cannot be made as the Britol 50T-water mixture did not exhibit this phenomena.

For a 20% water-80% LVT 200 mixture, the *insitu* to input holdup ratio is
Figure 4.18 In situ to input volume fraction of water vs. Total superficial velocity for LVT-200 oil

*Figure 4.18 In situ to input volume fraction of water vs. Total superficial velocity for LVT-200 oil.*

- 80% input water conc.
- 70% input water conc.
- 60% input water conc.
- 50% input water conc.
- 40% input water conc.
- 30% input water conc.
- 20% input water conc.
Figure 4.19 Insitu to input volume fraction of water vs. Total superficial velocity for Britol 50T oil
between 0.6 and 0.65, for mixture velocities in the range of 0.4 to 0.6 m/s. There is a slight increase in this ratio with an increase in the mixture velocity. However, the increase is more apparent as the input percentage of the water is increased. For an 80% water-20% LVT 200 mixture the \textit{insitu} to input holdup ratio is about 0.74 at mixture velocity of 0.4 m/s. This ratio increases to about 0.76 at 0.5 m/s and attains a value of 0.8 with further increase in the velocity 0.6 m/s. All the interim oil-water concentrations show the same trends. The \textit{insitu} to input holdup is seen to increase with an increase in the water cut.

Similar variations were seen for Britol 50T-water mixtures. However, the ratio is much lower, lying between 0.1 and 0.3. For a 20% water-80% Britol mixture, this ratio is about 0.11 for an input mixture velocity of 0.4 m/s. As the mixture velocity is increased to 0.8 m/s, there is a gradual increase in the \textit{insitu} to input holdup ratio to about 0.13. For an 80% water-20% Britol mixture the \textit{insitu} to input holdup ratio increases to 0.22 for an input mixture velocity of 0.4 m/s. Increasing the velocity to 0.6 m/s results in a value of 0.27 and finally to about 0.3 for a velocity of 0.8 m/s. As seen for LVT 200-water mixtures, the interim oil-water percentages show the same trends and the increase in the \textit{insitu} to input holdup ratio becomes more distinct with an increase in the input water concentration.

In an effort to understand more about the semi-segregated flow characteristics of the oil-water mixtures inside the pipelines, the \textit{insitu} velocity of the water phase was calculated for different input concentrations. The velocity of the water phase is calculated from the holdup data by the following equations:

\[
\nu_{sw} = q_w / A_p
\]  
(4.1.4.1)
where, \( v_{sw} \) = superficial water velocity, m/s

\[ q_w = \text{flowrate of the water phase, m}^3/\text{s} \]

\( A_p = \text{cross sectional area of pipeline, m}^2 \)

\[ v_w = q_w / A_w \quad (4.1.4.2) \]

where, \( v_w \) = \textit{insitu} water velocity, m/s

\( A_w = \text{cross sectional area occupied by the water phase, m}^2 \)

\[ H_w = A_w / A_p \quad (4.1.4.3) \]

where, \( H_w \) = \textit{insitu} holdup of the water phase

From Equations 4.1.4.1, 4.1.4.2 and 4.1.4.3,

\[ v_w = v_{sw} / H_w \quad (4.1.4.4) \]

The \textit{insitu} water velocities for both the oils have been calculated using this equation and are given in Tables 4.3 and 4.4. It can be seen that the \textit{insitu} water velocities are much higher when Britol and water are flowing in the pipeline than for the LVT 200-water flow, under the same flow conditions. At a mixture velocity of 0.6 m/s and a water cut of 80%, the \textit{insitu} water velocities with Britol and LVT 200 in the system are 2.19 and 0.77 m/s (Appendix B). As the water percentage decreases to 60%, the \textit{insitu} velocities are seen to increase to 3.61 and 0.81 m/s, for water flowing with Britol and LVT, respectively. A further increase in velocities is seen as the water percentage is decreased. At a 20% water percentage the \textit{insitu} velocities of the water phase for Britol-water and LVT 200-water mixtures are seen to be 5.0 and 0.97 m/s.

For both the oil-water mixtures the \textit{insitu} water velocity is seen to increase with an increase in the mixture velocity, as expected. It is also seen that the water velocity in
<table>
<thead>
<tr>
<th>Total Mixture Velocity, m/s</th>
<th>80% input water concentration</th>
<th>70% input water concentration</th>
<th>60% input water concentration</th>
<th>50% input water concentration</th>
<th>40% input water concentration</th>
<th>30% input water concentration</th>
<th>20% input water concentration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>input</td>
<td>insitu</td>
<td>input</td>
<td>insitu</td>
<td>input</td>
<td>insitu</td>
<td>input</td>
</tr>
<tr>
<td>0.4</td>
<td>0.32</td>
<td>0.54</td>
<td>0.28</td>
<td>0.55</td>
<td>0.24</td>
<td>0.57</td>
<td>0.20</td>
</tr>
<tr>
<td>0.5</td>
<td>0.40</td>
<td>0.66</td>
<td>0.35</td>
<td>0.68</td>
<td>0.30</td>
<td>0.69</td>
<td>0.25</td>
</tr>
<tr>
<td>0.6</td>
<td>0.48</td>
<td>0.77</td>
<td>0.42</td>
<td>0.80</td>
<td>0.36</td>
<td>0.81</td>
<td>0.30</td>
</tr>
</tbody>
</table>

Table 4.3 Comparison of input to *insitu* water velocities at different water concentrations in full pipe flow for LVT 200
<table>
<thead>
<tr>
<th>Total Mixture Velocity, m/s</th>
<th>80% input water concentration</th>
<th>70% input water concentration</th>
<th>60% input water concentration</th>
<th>50% input water concentration</th>
<th>40% input water concentration</th>
<th>30% input water concentration</th>
<th>20% input water concentration</th>
<th>10% input water concentration</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.4</td>
<td>0.32</td>
<td>1.82</td>
<td>0.28</td>
<td>0.04</td>
<td>0.24</td>
<td>3.00</td>
<td>0.20</td>
<td>0.00</td>
</tr>
<tr>
<td>0.5</td>
<td>0.40</td>
<td>2.10</td>
<td>0.35</td>
<td>0.25</td>
<td>0.30</td>
<td>3.37</td>
<td>0.20</td>
<td>0.15</td>
</tr>
<tr>
<td>0.6</td>
<td>0.48</td>
<td>2.19</td>
<td>0.42</td>
<td>0.30</td>
<td>0.36</td>
<td>3.91</td>
<td>0.25</td>
<td>0.18</td>
</tr>
<tr>
<td>0.7</td>
<td>0.56</td>
<td>2.44</td>
<td>0.49</td>
<td>0.35</td>
<td>0.42</td>
<td>4.22</td>
<td>0.30</td>
<td>0.24</td>
</tr>
<tr>
<td>0.8</td>
<td>0.64</td>
<td>2.69</td>
<td>0.56</td>
<td>0.40</td>
<td>0.48</td>
<td>4.41</td>
<td>0.40</td>
<td>0.32</td>
</tr>
<tr>
<td>0.9</td>
<td>0.72</td>
<td>2.93</td>
<td>0.63</td>
<td>0.45</td>
<td>0.56</td>
<td>4.62</td>
<td>0.45</td>
<td>0.24</td>
</tr>
<tr>
<td>1.0</td>
<td>0.80</td>
<td>3.15</td>
<td>0.70</td>
<td>0.50</td>
<td>0.64</td>
<td>4.83</td>
<td>0.50</td>
<td>0.24</td>
</tr>
</tbody>
</table>

Table 4.4 Comparison of input to \textit{in situ} water velocities at different water concentrations in full pipe flow for BRITOL 50T
the system increases with a decrease in the water cut. This is due to the fact that when more oil is present above the water phase, it occupies a greater cross-section of the pipeline and therefore, the reduction in the cross-section area of the water phase results in a increased velocity (steady-state flow). The *insitu* water velocities are higher for Britol-water flows due to the greater viscosity of the oil, as compared to LVT 200. The Britol oil layers are thicker than that of LVT 200, as seen in the previous section, and therefore result in a greater reduction in the cross-sectional area of flow for the water. These higher velocities at the bottom of the pipe can result in higher corrosion rates there. This has been reported by Menezes (1994) for Britol-water mixtures.

The pressure gradients, using the single phase relationships, have been calculated from the *insitu* water velocities. The calculated gradients are seen in Tables 4.5 and 4.6. It was assumed that the total diameter of the pipeline was occupied by the water phase, for simplicity. The calculated values of the pressure gradient are seen to be extremely large, inspite of making this conservative assumption. The accurate approach would be to use the hydraulic diameter (the ratio of the cross-sectional area occupied by the water phase to the wetted perimeter), but this value would be less than the diameter of the pipeline. It would therefore decrease the Reynold's number and increase the friction factor. This would result in an even higher pressure gradient in the pipeline (Chapter 2). The elevated values of the pressure gradients suggest that factors other than the velocity of the phases influence the pressure gradients. Some of the important ones are surface tension, density, viscosity and the characteristics of the oil-water mixtures. Much more research is required to understand the effect of these properties on the mixture characteristics and
Table 4.5 Calculated pressure gradients for LVT-200 oil and water at different concentrations using the *insitu* water velocities

<table>
<thead>
<tr>
<th>Total Mixture Velocity (m/s)</th>
<th>80% input water concentration (N/m²)</th>
<th>70% input water concentration (N/m²)</th>
<th>60% input water concentration (N/m²)</th>
<th>50% input water concentration (N/m²)</th>
<th>40% input water concentration (N/m²)</th>
<th>30% input water concentration (N/m²)</th>
<th>20% input water concentration (N/m²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.4</td>
<td>30.7</td>
<td>31.8</td>
<td>34.0</td>
<td>36.1</td>
<td>37.1</td>
<td>39.3</td>
<td>41.4</td>
</tr>
<tr>
<td>0.5</td>
<td>43.6</td>
<td>46.1</td>
<td>47.4</td>
<td>49.9</td>
<td>53.6</td>
<td>54.8</td>
<td>59.8</td>
</tr>
<tr>
<td>0.6</td>
<td>57.1</td>
<td>61.3</td>
<td>62.8</td>
<td>64.2</td>
<td>65.5</td>
<td>71.0</td>
<td>85.6</td>
</tr>
</tbody>
</table>
Table 4.6 Calculated pressure gradients for Britol 50T oil and water at different concentrations using the *insitu* water velocities

<table>
<thead>
<tr>
<th>Total Mixture Velocity (m/s)</th>
<th>80% input water concentration (N/m²)</th>
<th>70% input water concentration (N/m²)</th>
<th>60% input water concentration (N/m²)</th>
<th>50% input water concentration (N/m²)</th>
<th>40% input water concentration (N/m²)</th>
<th>30% input water concentration (N/m²)</th>
<th>20% input water concentration (N/m²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.4</td>
<td>528.7</td>
<td>638.2</td>
<td>1463.3</td>
<td>1681.1</td>
<td>1765.1</td>
<td>2149.6</td>
<td>2314.2</td>
</tr>
<tr>
<td>0.5</td>
<td>679.2</td>
<td>880.7</td>
<td>1793.5</td>
<td>2182.6</td>
<td>2275.7</td>
<td>3023.8</td>
<td>3161.0</td>
</tr>
<tr>
<td>0.6</td>
<td>731.0</td>
<td>1032.0</td>
<td>2326.3</td>
<td>2773.5</td>
<td>3343.8</td>
<td>3761.6</td>
<td>4033.4</td>
</tr>
<tr>
<td>0.7</td>
<td>883.2</td>
<td>1262.5</td>
<td>2549.3</td>
<td>2889.6</td>
<td>3733.9</td>
<td>4493.9</td>
<td>4918.1</td>
</tr>
<tr>
<td>0.8</td>
<td>1047.6</td>
<td>1504.1</td>
<td>2571.0</td>
<td>3091.5</td>
<td>4310.6</td>
<td>5439.0</td>
<td>5794.3</td>
</tr>
</tbody>
</table>
the behaviour of the oil-water emulsions.

4.2 Three phase oil-water-gas, stratified flows

A limited number of experiments were carried out in the high pressure horizontal flow loop using a 50% water-50% LVT 200 mixture at atmospheric pressure and a pressure of $1.7 \times 10^4$ N/m$^2$. The liquid film heights were determined at velocities of 0.15, 0.25 and 0.32 m/s using a sampling tube. The superficial gas velocities used were 1.5, 3.0 and 4.5 m/s.

4.2.1 Film heights

The dimensionless total film thickness and water film thickness at atmospheric pressure and $1.7 \times 10^4$ N/m$^2$ are plotted in Figures 4.20 and 4.21 and 4.22 and 4.23, respectively. Experimental errors of ±5% for low gas velocities and of ±15% for high gas velocities were involved in the measurement of the thickness of the films. This was due to increased levels of mixing and larger amplitude waves at the oil-water and gas-oil interfaces, respectively. Error bars have been incorporated in Figure 4.20, as an illustration. Error bars have not been included in the other figures due to the proximity of the data points.

Figure 4.20 shows that the total film thicknesses increase with an increase in the liquid velocity. At a gas velocity of 1.5 m/s the dimensionless film thickness is 0.5, for a mixture velocity of 0.15 m/s. The thickness increases gradually to about 0.55 at 0.25 m/s and finally to 0.6 for a superficial liquid velocity of 0.32 m/s. It can also be seen that
Figure 4.20 Effect of gas velocity on the total film thickness at different liquid velocities (System at atmospheric pressure; 50:50 LVT-200-Water mixture)
Figure 4.21 Effect of gas velocity on the total film thickness at different liquid velocities (System at $1.7 \times 10^4$ N/m$^2$; 50:50 LVT-200-Water mixture)
Figure 4.22 Effect of gas velocity on the water film thickness at different liquid velocities (System at atmospheric pressure; 50:50 LVT-200-Water mixture)
Figure 4.23 Effect of gas velocity on the water film thickness at different liquid velocities
(System at $1.7 \times 10^5$ N/m$^2$; 50:50 LVT-200-Water mixture)
as the gas velocity is increased, the film becomes thinner at each liquid velocity. When
the gas velocity is increased to 4.5 m/s, the total film thickness decreases to about 0.40,
h/D, at a liquid velocity of 0.15 m/s. This value increases with an increase in the input
liquid velocity and a lower h/D (in comparison to a gas velocity of 1.5 m/s) of 0.48 is
observed at 0.32 m/s. An interim gas velocity of 3.0 m/s shows the same trends in the
film heights. The h/D values are seen to lie between those observed for gas velocities of
1.5 and 4.5 m/s.

At a system pressure of $1.7 \times 10^5$ N/m$^2$ the total film heights obtained are shown
in Figure 4.21. For a gas velocity of 1.5 m/s, the total film thickness of an oil-water
mixture flowing at 0.15 m/s was seen to be about 0.38. The h/D is seen to increase to
about 0.45 at a superficial liquid velocity of 0.32 m/s. When the gas velocity is raised to
4.5 m/s, the total film thickness is about 0.30 for a liquid velocity of 0.15 m/s. This value
increases gradually to 0.35 for a total liquid velocity of 0.32 m/s. It is observed from the
plot that the total film thicknesses for the higher pressure are less than that at atmospheric
pressure. However, a comparison of Figures 4.20 and 4.21 shows a similar variation in
the total film heights at both the pressures.

The water layer thicknesses show a similar variation with a change in the
superficial liquid and gas velocities. Figure 4.22 shows a plot of the water film heights
at different gas and liquid velocities at atmospheric pressure. At a gas velocity of 1.5 m/s
the water film height is about 0.37, h/D, for a liquid velocity of 0.15 m/s. The thickness
increases to 0.40 and 0.42 at liquid velocities of 0.25 and 0.32 m/s, respectively. At a gas
velocity of 4.5 m/s the water layer thickness increases form 0.24 to 0.30 with an increase
in the liquid velocity from 0.15 to 0.32 m/s. At the higher pressure of $1.7 \times 10^5$ N/m$^2$, the water layer is also seen to become thinner (Figure 4.23). The water layer thickness is seen to increase slightly from 0.32 to about 0.38 with an increase in the superficial liquid velocity from 0.15 to 0.32 m/s at a gas velocity of 1.5 m/s. The water layer gets thinner with an increase in the gas velocity to 4.5 m/s. The water layer h/D increases from 0.20 to 0.26 as the liquid velocity is varied from 0.15 to 0.32 m/s.

This data again establishes the presence of a water layer at the bottom of the pipe in three-phase flow. The decrease in the thickness of these layers at the higher pressure can be attributed to the increase in the density of the gas which has a greater influence on the waves at the oil-water and gas-oil interfaces. If the thickness of the oil layer is determined by taking the difference in the total and water film heights, it is found that at the higher pressure, the denser gas has a greater effect on the oil layer than the water layer. It is observed that the oil is swept away much easier than the water and this leads to much thinner oil films. This is seen by calculating the percentage of the pipe cross-sectional area occupied (insitu holdup) by the oil and water phases.

### 4.2.2 Holdup

The insitu holdup of each phase is calculated from the film heights using the Equations 2.2.2 and 2.2.3, developed by Taitel and Dukler (1976). These equations determine the cross-sectional area occupied by the gas and liquid phases. Dividing both the relations by the total cross-sectional area of the pipeline ($\pi D^2/4$) we can get the percentage area occupied by the liquid and the gas phases (holdup). The gas and the
total liquid holdup can be determined with the total film height. The water holdup is
determined from the thickness of the water layer and the difference between this value
and the total liquid holdup gives the holdup of the oil phase. The holdups of the liquid
and the gas phases can therefore be estimated using these simplified forms, respectively:

\[
A_L = \frac{1}{\pi} \left[ \pi - \cos^{-1}(2h_L - 1) + (2h_L - 1)\sqrt{1 - (2h_L - 1)^2} \right] \quad (4.2.2.1)
\]

\[
A_G = \frac{1}{\pi} \left[ \cos^{-1}(2h_L - 1) + (2h_L - 1)\sqrt{1 - (2h_L - 1)^2} \right] \quad (4.2.2.2)
\]

where,

- \(A_L\) = percentage of pipe cross-sectional area occupied by the liquid
- \(A_G\) = percentage of the pipe cross-sectional area occupied by the gas

From Tables 4.7 and 4.8 it is seen that the total liquid and water holdups increase
with an increase in the superficial liquid velocity and decrease with an increase in the gas
velocity. Also, due to the increased density of the gas at the higher pressure, the total and
water phase holdups are seen to decrease. The oil and water together occupy 39.3 percent
of the pipe cross-sectional area at atmospheric pressure and 29.3 percent at the higher
pressure of \(1.7 \times 10^5 \text{ N/m}^2\), at liquid and gas superficial velocities of 0.15 m/s and 1.5
m/s, respectively. Water alone occupies 24.3 percent of the pipe cross-section at
atmospheric pressure and 21.2 percent at the elevated pressure under the same conditions.
It is seen that the increase in pressure has a much greater effect on the oil holdup as
compared to that of water. In the above mentioned case the water and oil holdups
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=1.5 m/s</th>
<th>Superficial Gas Velocity=3.0 m/s</th>
<th>Superficial Gas Velocity=4.5 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Atmospheric Pressure 1.7*10^5 N/m²</td>
<td>Atmospheric Pressure 1.7*10^5 N/m²</td>
<td>Atmospheric Pressure 1.7*10^5 N/m²</td>
</tr>
<tr>
<td>0.15</td>
<td>39.27</td>
<td>29.29</td>
<td>33.28</td>
</tr>
<tr>
<td>0.25</td>
<td>43.26</td>
<td>31.32</td>
<td>36.29</td>
</tr>
<tr>
<td>0.32</td>
<td>49.20</td>
<td>34.30</td>
<td>43.27</td>
</tr>
</tbody>
</table>

Table 4.7 Comparison of total liquid holdups at different pressures for a 50-50 mixture of LVT 200 and water in stratified three-phase flow
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=1.5 m/s</th>
<th>Superficial Gas Velocity=3.0 m/s</th>
<th>Superficial Gas Velocity=4.5 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Atmospheric Pressure</td>
<td>1.7*10^5 N/m²</td>
<td>Atmospheric Pressure</td>
</tr>
<tr>
<td>0.15</td>
<td>24.30</td>
<td>21.20</td>
<td>19.82</td>
</tr>
<tr>
<td>0.25</td>
<td>29.30</td>
<td>24.45</td>
<td>26.42</td>
</tr>
<tr>
<td>0.32</td>
<td>32.30</td>
<td>29.30</td>
<td>27.39</td>
</tr>
</tbody>
</table>

Table 4.8 Comparison of water holdups at different pressures for a 50-50 mixture of LVT 200 and water in stratified three-phase flow
decrease by about 3% and 7%, respectively. This is in agreement with the film height observations as seen in the previous section. This trend is seen for all liquid and gas velocities.

Table 4.9 shows the holdup of the gas phase. It is seen that the gas occupies a cross-sectional area which is greater than that occupied by both the liquid phases. From the holdup data the \textit{insitu} velocities of the oil, water and the gas phases can be calculated at both pressures, using the equations developed in section 4.1.4. The results are shown in Tables 4.10 and 4.11.

At both the pressures the following observations can be made. All the three phases are seen to accelerate with an increase in the total superficial liquid velocity and the gas velocity. The \textit{insitu} velocity of the gas is seen to be greater than either of the two liquid phases, in all cases. The velocity of the oil layer is seen to be greater than that of the water layer. As the gas velocities are high, the shear stresses at the gas and the adjoining oil interface are large. This "sweeping action" or "drag" results in a reduction of the cross-sectional area occupied by the oil phase (and therefore, thinner films) and this in turn accelerates the oil layer. It is noticed that the oil layer is never accelerated to the gas velocity. The oil-water interface exhibits the same phenomena. However, as the oil velocities are lower than that of the gas, the water occupies a greater cross-sectional area. This results in lower water velocities.

\textbf{4.3 Three-phase Britol-water-gas, slug flow}

A study was carried out in the plexiglass pipeline to examine three-phase stratified
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=1.5 m/s</th>
<th>Superficial Gas Velocity=3.0 m/s</th>
<th>Superficial Gas Velocity=4.5 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Atm. Pressure 1.7*10^3 N/m^2</td>
<td>Atm. Pressure 1.7*10^3 N/m^2</td>
<td>Atm. Pressure 1.7*10^3 N/m^2</td>
</tr>
<tr>
<td>0.15</td>
<td>60.73</td>
<td>70.71</td>
<td>66.72</td>
</tr>
<tr>
<td>0.25</td>
<td>56.74</td>
<td>69.68</td>
<td>63.71</td>
</tr>
<tr>
<td>0.32</td>
<td>50.80</td>
<td>64.70</td>
<td>56.73</td>
</tr>
</tbody>
</table>

Table 4.9 Comparison of gas holdups at different pressures for a 50:50 mixture of LVT 200 and water in stratified three-phase flow
Table 4.10 Comparison of insitu velocities for a 50-50 mixture of LVT 200 and water in stratified three-phase flow at atmospheric pressure

<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=1.5 m/s</th>
<th>Superficial Gas Velocity=3.0 m/s</th>
<th>Superficial Gas Velocity=4.5 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Water</td>
<td>Oil</td>
<td>Gas</td>
</tr>
<tr>
<td>0.15</td>
<td>0.31</td>
<td>0.50</td>
<td>2.47</td>
</tr>
<tr>
<td>0.25</td>
<td>0.43</td>
<td>0.89</td>
<td>2.64</td>
</tr>
<tr>
<td>0.32</td>
<td>0.49</td>
<td>0.95</td>
<td>2.95</td>
</tr>
</tbody>
</table>

Table 4.10 Comparison of insitu velocities for a 50-50 mixture of LVT 200 and water in stratified three-phase flow at atmospheric pressure
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=1.5 m/s</th>
<th>Superficial Gas Velocity=3.0 m/s</th>
<th>Superficial Gas Velocity=4.5 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Water</td>
<td>Oil</td>
<td>Gas</td>
</tr>
<tr>
<td>0.15</td>
<td>0.35</td>
<td>0.93</td>
<td>2.12</td>
</tr>
<tr>
<td>0.25</td>
<td>0.49</td>
<td>1.82</td>
<td>2.16</td>
</tr>
<tr>
<td>0.32</td>
<td>0.55</td>
<td>2.29</td>
<td>2.31</td>
</tr>
</tbody>
</table>

Table 4.11 Comparison of *insitu* velocities for a 50-50 mixture of LVT 200 and water in stratified three-phase flow at a pressure of $1.7 \times 10^5$ N/m².
flow using Britol 50T. When Britol was used, it was found that, due to the high viscosity, slug flows occurred even at the lowest liquid velocity of 0.2 m/s. It was decided to examine the film thicknesses and phase distribution in the films flowing between slugs.

### 4.3.1 Film thicknesses

The water and total film heights were recorded for superficial liquid velocities ranging from 0.2 m/s to 0.8 m/s. The gas velocities used were from 0.8 m/s to 5 m/s. The total film heights are shown in Figures 4.24 to 4.27. Experimental errors in the range of of +/-5% to +/-10% can be taken into account. Error bars have been shown in Figure 4.24, as an illustration. It is seen that the total film heights increase with an increase in the input water percentage and decrease with an increase in the gas velocity at each total liquid velocity.

Figure 4.24 shows that for a 80% water-20% Britol 50T mixture at a total superficial velocity of 0.2 m/s, the total film height, h/D, is 0.37, at a gas velocity of 0.8 m/s. The height decreases to 0.27 and then to 0.22 as the gas velocity is increased to 2.4 and 3.7 m/s, respectively. Finally, the film thickness reduces to 0.17 at a gas velocity of 4.9 m/s. As the water cut is decreased to 20%, a reduced film height of 0.28 is seen at a gas velocity of 0.8 m/s. The thickness decreases to 0.2, 0.15 and 0.12 as the gas velocity increases to 2.4 m/s, 3.7 m/s and finally to 4.9 m/s, respectively.

Figures 4.25 to 4.27 show the same trends as the total liquid velocity is increased. The film heights are seen to increase with an increase in the liquid velocity at all oil-water concentrations. For a 80% water-20% oil mixture at a superficial velocity of 0.8 m/s
Figure 4.24 Total film thickness at different oil-water concentrations vs. Gas velocity
(Total liquid velocity = 0.2 m/s; Oil: BRITOL 50T)
Figure 4.25 Total film thickness at different oil-water concentrations vs. gas velocity (Total liquid velocity = 0.4 m/s; Oil: BRITOL 50T)
Figure 4.26 Total film thickness at different oil-water concentration vs. Gas velocity
(Total liquid velocity=0.6 m/s; Oil: BRITOL 50T)
Figure 4.27 Total film thickness at different oil-water concentrations vs. Gas velocity (Total liquid velocity=0.8 m/s; Oil: BRITOL 50T)
(Figure 4.27), it is seen that the film thickness is 0.57 when the gas velocity is 0.8 m/s. The film height decreases to 0.45 and then to 0.38 when the gas velocity is 2.4 and 3.7 m/s, respectively. At the highest gas velocity of 4.9 m/s the film has a h/D of 0.31.

Similar trends are seen for superficial liquid velocities of 0.4 and 0.6 m/s as seen in Figures 4.25 and 4.26. The height of the film is seen to increase with an increase in the water percentage at all gas velocities. At high gas velocities the interfacial shear stress between the gas and oil phases is greater (as explained in section 4.2.2) which results in thinner films. The water film heights show a similar trend.

The water film thicknesses are shown in Figures 4.28 to 4.31. It is observed that there is still a water layer at the bottom of the pipe and the height of this layer increases with an increase in the input water fraction and the total input liquid velocity. Figure 4.28 shows the variation in the water film thicknesses with gas velocity at a superficial liquid velocity of 0.2 m/s. At a 80% water cut, the thickness of the water layer decreases from a h/D of 0.23 at a gas velocity of 0.8 m/s to 0.10 at a gas velocity of 4.9 m/s. The water films for a 20% water cut are thinner. The h/D varies from 0.18 at a gas velocity of 0.8 m/s to 0.07 at a gas velocity of 4.9 m/s. Similar variations are seen for superficial velocities of 0.4 and 0.6 m/s (Figures 4.29 and 4.30). The water film heights are seen to increase with an increase in the liquid velocity. Figure 4.31 shows the water film thicknesses at a liquid velocity of 0.8 m/s. For a 80% input water concentration the water layer thickness decreases from a h/D of 0.47 at a gas velocity of 0.8 m/s to 0.25 at a gas velocity of 4.9 m/s. At a 20% input water concentration the water layer thickness varies from 0.30 for a gas velocity of 0.8 m/s to 0.15 for gas flowing at a velocity of 4.9 m/s.
Figure 4.28 Water film thickness at different oil-water concentrations vs. Gas velocity (Total liquid velocity=0.2 m/s; Oil: Britol 50T)
Figure 4.29 Water film thickness at different oil-water concentrations vs. Gas velocity (Total liquid velocity=0.4 m/s; Oil: BRITOL 50T)
Figure 4.30 Water film thickness at different oil-water concentrations vs. Gas velocity
(Total liquid velocity=0.6 m/s; Oil: BRITOL 50T)
Figure 4.31 Water film thickness at different oil-water concentrations vs. Gas velocity
(Total liquid velocity=0.8 m/s; Oil: BRITOL 50T)
The film thickness data shows that the oil layer is much thinner than that of water. The cross-sectional area occupied by the liquid phases (the *insitu* holdup) increases with an increase in the percentage of the water in the system. This can be seen by calculating the fraction of the pipe area occupied by the phases as shown in section 4.2.2.

4.3.2 Holdup

The total liquid and water phase holdups have been calculated at each gas velocity using the equations given in section 4.2.2, for total superficial liquid velocities ranging from 0.2 to 0.8 m/s. The gas holdup is also has also been calculated and all the data is shown in Tables 4.12, 4.13 and 4.14.

As seen in section 4.2.2, for the low viscosity LVT 200, the water holdup is greater than that of oil for all input liquid and gas velocities. This corroborates the fact that the water layer thickness is greater as compared to that of Britol 50T. Tables 4.12 and 4.13 show that the oil and water holdups increase with an increase in the superficial liquid velocity and the input water percentage. The holdups are seen to decrease with an increase in the gas velocity. This again is similar to the results in section 4.2.2.

The gas fraction is shown in Table 4.14. It is seen that the gas occupies a comparatively large cross-sectional of the pipeline at all liquid flowrates. The holdup of the gas decrease with an increase in the total liquid velocity and the input water percentage. The gas is seen to occupy a progressively greater pipe volume as it's velocity increases. The velocity of the three phases is calculated from the holdup data as shown earlier in section 4.1.4.
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=0.8 m/s</th>
<th>Superficial Gas Velocity=2.3 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>10.69</td>
</tr>
<tr>
<td>0.40</td>
<td>11.65</td>
<td>14.87</td>
</tr>
<tr>
<td>0.60</td>
<td>10.32</td>
<td>18.19</td>
</tr>
<tr>
<td>0.80</td>
<td>8.40</td>
<td>8.65</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=3.6 m/s</th>
<th>Superficial Gas Velocity=4.9 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>3.96</td>
</tr>
<tr>
<td>0.40</td>
<td>4.35</td>
<td>3.73</td>
</tr>
<tr>
<td>0.60</td>
<td>6.90</td>
<td>7.55</td>
</tr>
<tr>
<td>0.80</td>
<td>4.29</td>
<td>4.52</td>
</tr>
</tbody>
</table>

Table 4.12 *In situ* holdups of Britol 50T at different oil-water concentrations and gas velocities in three-phase slug flow
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=0.8 m/s</th>
<th>Superficial Gas Velocity=2.3 m/s</th>
<th>Superficial Gas Velocity=3.6 m/s</th>
<th>Superficial Gas Velocity=4.9 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
<td>60% input water concentration</td>
<td>80% input water concentration</td>
<td>20% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>12.23</td>
<td>14.23</td>
<td>17.38</td>
</tr>
<tr>
<td>0.40</td>
<td>11.27</td>
<td>16.31</td>
<td>20.66</td>
<td>22.92</td>
</tr>
<tr>
<td>0.60</td>
<td>18.45</td>
<td>22.92</td>
<td>29.97</td>
<td>33.64</td>
</tr>
<tr>
<td>0.80</td>
<td>25.23</td>
<td>31.19</td>
<td>39.85</td>
<td>46.18</td>
</tr>
<tr>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
<td>60% input water concentration</td>
<td>80% input water concentration</td>
<td>20% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>6.81</td>
<td>8.51</td>
<td>10.33</td>
</tr>
<tr>
<td>0.40</td>
<td>8.50</td>
<td>12.23</td>
<td>17.37</td>
<td>17.37</td>
</tr>
<tr>
<td>0.60</td>
<td>12.23</td>
<td>17.37</td>
<td>24.06</td>
<td>26.39</td>
</tr>
<tr>
<td>0.80</td>
<td>16.31</td>
<td>21.78</td>
<td>28.78</td>
<td>34.87</td>
</tr>
<tr>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
<td>60% input water concentration</td>
<td>80% input water concentration</td>
<td>20% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>3.77</td>
<td>4.50</td>
<td>5.21</td>
</tr>
<tr>
<td>0.40</td>
<td>4.46</td>
<td>6.00</td>
<td>7.64</td>
<td>9.41</td>
</tr>
<tr>
<td>0.60</td>
<td>6.80</td>
<td>11.27</td>
<td>12.24</td>
<td>14.23</td>
</tr>
<tr>
<td>0.80</td>
<td>9.41</td>
<td>12.24</td>
<td>17.38</td>
<td>19.54</td>
</tr>
</tbody>
</table>

Table 4.13 *Insitu* holdups of water at different oil-water concentrations and gas velocities in three-phase slug flow
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=0.8 m/s</th>
<th></th>
<th></th>
<th>Superficial Gas Velocity=2.3 m/s</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
<td>60% input water concentration</td>
<td>80% input water concentration</td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>77.08</td>
<td>72.41</td>
<td>66.36</td>
<td>-</td>
<td>87.77</td>
</tr>
<tr>
<td>0.40</td>
<td>77.08</td>
<td>68.82</td>
<td>60.15</td>
<td>56.34</td>
<td>83.69</td>
<td>81.55</td>
</tr>
<tr>
<td>0.60</td>
<td>71.23</td>
<td>58.89</td>
<td>51.27</td>
<td>42.39</td>
<td>80.46</td>
<td>77.08</td>
</tr>
<tr>
<td>0.80</td>
<td>66.36</td>
<td>60.15</td>
<td>47.45</td>
<td>41.11</td>
<td>78.22</td>
<td>71.22</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=3.6 m/s</th>
<th></th>
<th></th>
<th>Superficial Gas Velocity=4.9 m/s</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
<td>60% input water concentration</td>
<td>80% input water concentration</td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>90.59</td>
<td>88.83</td>
<td>84.74</td>
<td>-</td>
<td>93.20</td>
</tr>
<tr>
<td>0.40</td>
<td>89.67</td>
<td>87.76</td>
<td>80.46</td>
<td>77.08</td>
<td>92.36</td>
<td>89.67</td>
</tr>
<tr>
<td>0.60</td>
<td>83.69</td>
<td>78.22</td>
<td>74.77</td>
<td>70.03</td>
<td>88.83</td>
<td>83.69</td>
</tr>
<tr>
<td>0.80</td>
<td>80.45</td>
<td>75.93</td>
<td>71.23</td>
<td>65.13</td>
<td>87.77</td>
<td>84.72</td>
</tr>
</tbody>
</table>

Table 4.14 *Insitu* fractions of gas at different oil-water concentrations and gas velocities in three-phase slug flow
Table 4.15 shows the ratio of insitu to input gas velocities in the system at different oil-water compositions and varying superficial liquid and gas velocities. At a superficial liquid and gas velocities of 0.2 and 0.8 m/s, respectively the ratio of the insitu to input gas velocity increases from 1.40 m/s to 1.78 m/s with an increase in the water concentration from 40 to 80%. This increase in the ratio of the velocities is seen at all input liquid velocities. The insitu to input gas velocity also increases from 1.78 to 2.44 m/s with an increase in the total liquid velocity, for a 80-20% water-oil mixture for an input gas velocity of 0.8 m/s. Similar variations are seen for all input oil-water fractions and all superficial gas velocities.

The velocity of the oil and water phases varies with the input flowrate of the liquid phases and the gas velocity. As the input percentage of the liquid phases were also varied in these cases, their input flowrates depended on this factor in addition to the total superficial liquid velocity. The insitu velocities (or flowrates), on the other hand, varied with the input percentage of the liquids, the total superficial liquid velocity and the superficial gas velocity.

The change in velocity of the two liquid phases is apparent if the ratios of insitu to input velocities are compared. These are shown in Tables 4.16 and 4.17. It is seen that the oil layer is accelerated much more than the water layer and the insitu to input velocity ratio is higher at all oil-water percentages. This ratio increases with an increase in the gas velocity. The insitu to input ratio for oil decreases with an increase in the water percentage, at a fixed gas velocity. This is due to the decrease in the input flowrate of the oil phase. This ratio for the water layer is also seen to decrease with an increase in the
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=0.8 m/s</th>
<th>Superficial Gas Velocity=2.3 m/s</th>
<th>Superficial Gas Velocity=3.6 m/s</th>
<th>Superficial Gas Velocity=4.9 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
<td>60% input water concentration</td>
<td>80% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>1.40</td>
<td>1.59</td>
<td>1.78</td>
</tr>
<tr>
<td>0.40</td>
<td>1.34</td>
<td>1.54</td>
<td>1.78</td>
<td>1.90</td>
</tr>
<tr>
<td>0.60</td>
<td>1.40</td>
<td>1.70</td>
<td>1.95</td>
<td>2.36</td>
</tr>
<tr>
<td>0.80</td>
<td>1.43</td>
<td>1.66</td>
<td>2.11</td>
<td>2.44</td>
</tr>
</tbody>
</table>

Table 4.15 Ratio of \textit{insitu} to input velocities of gas at different oil-water concentrations and gas velocities in three-phase slug flow
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=0.8 m/s</th>
<th>Superficial Gas Velocity=2.3 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>8.12</td>
</tr>
<tr>
<td>0.40</td>
<td>8.87</td>
<td>6.12</td>
</tr>
<tr>
<td>0.60</td>
<td>5.41</td>
<td>4.37</td>
</tr>
<tr>
<td>0.80</td>
<td>3.93</td>
<td>3.21</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=3.6 m/s</th>
<th>Superficial Gas Velocity=4.9 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>40% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>18.37</td>
</tr>
<tr>
<td>0.40</td>
<td>16.75</td>
<td>11.75</td>
</tr>
<tr>
<td>0.60</td>
<td>10.58</td>
<td>7.04</td>
</tr>
<tr>
<td>0.80</td>
<td>6.56</td>
<td>5.12</td>
</tr>
</tbody>
</table>

Table 4.16 Ratio of *insitu* to input velocities of water at different oil-water concentrations and gas velocities in three-phase slug flow
<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=0.8 m/s</th>
<th>Superficial Gas Velocity=2.3 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>20% input water concentration</td>
</tr>
<tr>
<td></td>
<td>40% input water concentration</td>
<td>40% input water concentration</td>
</tr>
<tr>
<td></td>
<td>60% input water concentration</td>
<td>60% input water concentration</td>
</tr>
<tr>
<td></td>
<td>80% input water concentration</td>
<td>80% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>18.42</td>
</tr>
<tr>
<td>0.40</td>
<td>8.58</td>
<td>12.81</td>
</tr>
<tr>
<td>0.60</td>
<td>9.69</td>
<td>13.69</td>
</tr>
<tr>
<td>0.80</td>
<td>11.89</td>
<td>18.28</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Superficial Liquid Velocity, m/s</th>
<th>Superficial Gas Velocity=3.6 m/s</th>
<th>Superficial Gas Velocity=4.9 m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20% input water concentration</td>
<td>20% input water concentration</td>
</tr>
<tr>
<td></td>
<td>40% input water concentration</td>
<td>40% input water concentration</td>
</tr>
<tr>
<td></td>
<td>60% input water concentration</td>
<td>60% input water concentration</td>
</tr>
<tr>
<td></td>
<td>80% input water concentration</td>
<td>80% input water concentration</td>
</tr>
<tr>
<td>0.20</td>
<td>-</td>
<td>33.00</td>
</tr>
<tr>
<td>0.40</td>
<td>22.97</td>
<td>31.44</td>
</tr>
<tr>
<td>0.60</td>
<td>14.50</td>
<td>22.87</td>
</tr>
<tr>
<td>0.80</td>
<td>23.31</td>
<td>35.45</td>
</tr>
</tbody>
</table>

Table 4.17 Ratio of \textit{insitu} to input velocities of Britol 50T at different oil-water concentrations and gas velocities in three-phase slug flow
water cut. This is a result of the increased thickness of the water layer and therefore the increased cross-sectional area of flow.

The *insitu* water velocity is seen to be about 35 times the input velocity for a 20-80% water-oil mixture at a superficial velocity of 0.8 m/s and a gas velocity of 4.9 m/s. The corresponding *insitu* to input water velocity ratio is also seen to have the highest value of 10 at the same conditions. The *insitu* to input velocity ratio is seen to be much higher for the oil and water than for the gas. This is due to the greater cross-sectional area (the *insitu* holdup) of the gas as compared to the two liquid phases.

It is seen from this study that a water layer is always present at the bottom of the pipeline. The increase in the *insitu* to input velocity ratio of both the liquid phases becomes apparent with an increase in the gas velocity. The acceleration of the phases also depends on the input concentrations of the liquid phases and the superficial liquid velocity.
CHAPTER 5

CONCLUSIONS

Based on the results obtained in this study the following conclusions can be made.

1. Three flow regimes namely bubble, semi-segregated and semi-mixed were observed for the LVT 200-water mixtures. The mixture velocities studied were in the range of 0.2 to 1.4 m/s. This compares well with the observations of Guzov (1976). All the flow regimes reported by Oglesby (1979) were not observed. This is attributed to the much larger diameter of the experimental pipeline as compared to the ones used by researchers in the past. Britol 50T-water mixtures were found to be in the semi-segregated flow regime in the mixture velocity range of 0.4 to 0.8 m/s. This can be an effect of the higher viscosity of the oil in conjunction with the large diameter of the pipeline and also other mixture properties like, surface tension, density, and the dispersion phenomena or the flow type.

2. For LVT-200, phase inversion was seen to occur between 30 to 70% input water percentage for total superficial velocities of 0.8 m/s or greater. The inversion was seen to take place at a lower input water percentage with an increase in the total mixture velocity. An increase in the mixture velocity also resulted in a higher pressure gradient at the inversion point. The reported results agree well with the observations made by Charles (1961), Guzov (1976), Laflin and Oglesby (1976), Arirachakaran (1983) and Oglesby (1979).
3. For the range of velocities studied, no evidence of phase inversion was seen for Britol 50T. The mixing of the oil-water is only found at the oil-water interface. Sharp drops in the pressure gradients were observed at water concentrations in the range of 20 to 40%. This is due to the change in the mixture characteristics and due to water becoming the only phase in contact with the bottom of the pipeline at these input fractions. More work is recommended in larger diameter pipelines to determine the effect of the mixture properties. The study of the behaviour of the oil-water mixtures at greater velocities than the ones obtained with the present equipment is also highly recommended.

4. The pressure gradients were calculated for the oil-water mixtures using the weighting rules. This method does not predict the changes in the pressure gradient at the inversion point and at the transition between different types of flow. Better correlations have to be developed to predict the behaviour of the oil-water dispersion by taking into account the physical properties of the mixture.

5. Full pipe, oil-water flows were studied and the liquid film thicknesses determined. It was found that water exists as a discrete layer at the bottom of the pipe for all the velocities considered. These thicknesses are seen to depend on the total liquid velocity and the water cut. The film thicknesses increased upon increasing both these variables.

6. The \textit{insitu} holdups were found to be much less than the input concentrations. These findings do not agree with that of Malinowsky (1975), in which he reported that there was not a significant difference in the holdups in the segregated and dispersed flows. The liquid holdups are lower for Britol than LVT 200. When the individual phase velocities are calculated, it is found that the velocity of the water layer is much higher.
than anticipated. For Britol, the velocity of the water layer can be as much as five times
greater than that for LVT at the same conditions. The pressure gradients calculated from
the single-phase relationships, using these velocities of the water phase alone, were seen
to be much higher than those observed in the pipeline. This suggests that other mixture
properties also play a significant role on the physical characteristics of the dispersion and
the combined result is reflected in the pressure gradients in the pipeline.

7. For stratified three phase oil-water-gas flows, the total liquid film heights increased
with increase in total liquid velocity but decreased with increasing gas velocity. The oil
layer is affected more by the increase in the gas velocity than the water layer. At higher
pressures, the gas sweeps out more oil than water thus reducing the oil thickness much
more than the water. Water layers were still present at the bottom of the pipe.

8. The *insitu* holdups of the oil, water and gas phases were calculated using the
relationships developed by Taitel and Dukler (1976). The results were used to calculate
the *insitu* velocities of the three phases. The velocity of the gas phase, in the pipeline, was
found to be greater than that of the oil which in turn was greater than of the water phase.

9. For Britol 50T, the stratified flow between slugs was studied and again the
presence of water layers were noted. The thickness of the water films decreased with
increase in gas velocity.

10. For the stratified flow between slugs, holdups of Brotol 50T, water and the gas
phases were calculated from the film thicknesses. A large portion of the pipeline was seen
to be occupied by the gas. The *insitu* liquid and gas-phase velocities were found to be
much higher than the input velocities, as seen for three-phase LVT 200-water-gas flows.
REFERENCES


Sample calculation for pressure drop

Oil viscosity ( LVT 200 ) = 2 cP

Water viscosity = 1 cP

Oil density ( LVT 200 ) = 800 Kg/m³

Water density = 1000 Kg/m³

Pipeline diameter ( d ) = 0.1 m

Total Mixture ( superficial ) velocity ( v_m ) = 1.0 m/s

Input water fraction = 80%

Input oil fraction = 20%

Two-phase mixture density ( \rho_m ) = ( 0.8*1000 + 0.2*800 ) = 960 Kg/m³

Two-phase mixture viscosity ( \mu_m ) = ( 0.8*1 + 0.2*2 ) = 1.2 cP

Two-phase Reynolds number ( N_{Re} ) = ( \rho_m * v_m * d ) / \mu_m

\quad = ( 960*1*0.1 ) / ( 1.2*10^{-3} ) = 80,000

Friction factor ( f_{fp} ) = 0.079*N_{Re}^{-0.25} = 0.0047

Pressure Drop = ( 2*f_{fp} * \rho_m * v_m^2 ) / d

\quad = ( 2*0.0047*960*1.0^2 ) / 0.1 = 90.2 N/m³
Sample calculation for the insitu water velocity

Total Mixture (superficial) velocity \( (v_m) = 0.6 \) m/s

Input water fraction = 80%

Input (superficial) water velocity \( (v_{sw}) = 0.8 \times 0.6 = 0.48 \) m/s

For Britol 50T-water flows (Figure 4.19):

Insitu to input volume fraction of water = 0.28

Therefore, the insitu volume fraction of water = 0.28 \times 0.8 = 0.22

Insitu water velocity = \( 0.48 / 0.22 = 2.19 \) m/s

For LVT 200-water flows (Figure 4.18):

Insitu to input volume fraction of water = 0.78

Therefore, the insitu volume fraction of water = 0.78 \times 0.8 = 0.62

Insitu water velocity = \( 0.48 / 0.62 = 0.77 \) m/s