

Study of High Viscous Multiphase Flow Using OLGA Flow Simulator

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Abstract- The continuous depletion of conventional reserves of the world oil and gas has spurred investigation towards the exploration and production from unconventional sources of hydrocarbons such as heavy oil. However, heavy oils are known for their high liquid viscosities making them even more difficult and expensive to produce and transport in pipelines at ambient temperatures. As a consequence of this, a critical understanding of multiphase flow characteristics is vital to aid engineering design it has become imperative to investigate the rheology of high viscosity oils and ways of enhancing its production and transportation. In this study, the characteristics of high viscous oil flows were studied using OLGA flow simulator. A comparison between simulation results from the flow simulator and those of data acquired for high oil-gas viscosity experiments (i.e. for oil viscosity ranging from 0.7-5.0 Pa.s) for two phase flow parameters such liquid holdup and pressure gradient exhibited huge discrepancies and under prediction.

Keywords - High viscosity oil, Liquid holdup, OLGA, Pressure gradient

1 INTRODUCTION

In the oil and gas industry, heavy oils are petroleum liquids with API gravity $<22^\circ$ and viscosity > 0.1 Pa.s.

There is an increasing interest in the industry towards using unconventional resources like heavy oil to help satisfy the increasing world energy demand; this is because the conventional reserves are continuously being depleted due to several years of production and consumption. The quest for heavy oil production is also fuelled by its ready availability as illustrated in Figure 1.

Richard and Emil, (2003), writing for the United States Geological Survey (USGS) puts the technically recoverable heavy oil and natural bitumen as equal to reserves of conventional oil. Viscous oil hydrodynamic characteristics are significantly different from conventional oil (light oil), and this is mainly due to its physical properties. As a result of these different physical properties, heavy oil is more challenging to produce and transport. The major implication of these differences is seen in the design of heavy oil production systems as well as in the implementation of technologies which were mostly developed by hydrodynamics characteristics of light oil.

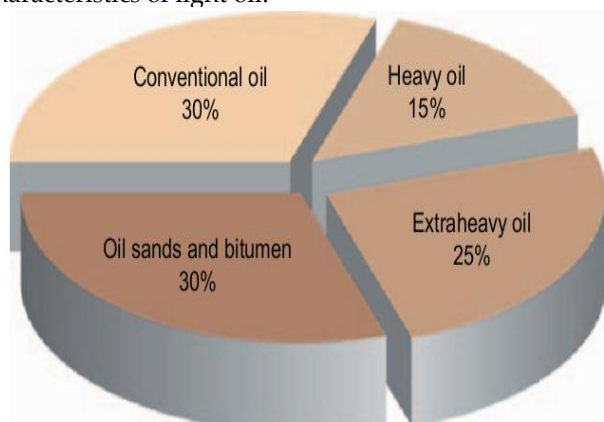


Fig. 1: Global heavy oil vs. conventional oil reserve (Baba et al., 2018)

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Some research works focusing on the effects of liquid viscosity on two-phase oil-gas flow in pipelines have been reported in the literature. Gokcal *et al.*, (2006), studied the impact of liquid viscosities of up to 0.589 Pa.s on oil-gas two-phase flow. The authors noted that existing models were insufficient in predicting the flow variables observed and that the intermittent flow region was enhanced with increased viscosity. Archibong-Eso *et al.*, (2018), Foletti *et al.*, (2011), Matsubara and Naito, (2011), and Zhao *et al.*, (2013) have reported increased intermittent flow region in their studies. More recently, Temitayo & Habeeb, (2018) studied the discharge behaviour of a sharp-edged circular orifice flow under low head from unsteady experimental procedure and validated result using Computational Fluid Dynamics CFD simulations. The study demonstrated that discharge coefficient cannot be taken as a constant value when dealing with low head; however, the simulation was able to forecast the trend but could not predict the exact values

Commercial dynamic multiphase flow simulators such as OLGA and Leda-Flow have been widely used comparatively in the analysis of experimental data. While OLGA was an independent flow simulator bought over by Schlumberger limited, Leda-Flow was developed by Kongsberg Digital AS, Norway Belt *et al.*, (2011), compared experimental field dataset with OLGA and LedaFlow. Their experimental dataset was obtained from an Elf owned flow loop with internal pipe diameters of 0.074 m and 0.146 m, pipeline inclinations used ranged from -2.9° to 90° from the horizontal. The authors concluded that both flow codes gave a good prediction in both oil-dominated well flow and gas condensate flow. For field measurements of pressure gradient and temperature, the flow codes were observed to have good prediction in the horizontal and nearly-horizontal slug flows. These codes, however, performed poorly in the vertical slug flow region. The poor performance was attributed to the presence of churn/annular flow which is not modelled correctly in the flow codes. The authors, however, did not provide the viscosity of liquid used in both the field and laboratory datasets.

Smith *et al.*, (2011), carried out two-phase oil-gas flow experiments in the SINTEF Multiphase Flow Laboratory with a test section of 52.92 m in length and an Internal pipe Diameter of 0.0686 m. Air was used as the gas phase while water and oil with viscosities of 0.075 Pa.s and 0.15 Pa.s respectively were used as the test liquids. Flow patterns, pressure drop, liquid holdup and interfacial friction factor were measured in the experiments. Comparative analysis with the multiphase flow simulator, OLGA showed a good prediction for the measurements obtained in the low viscosity oil (0.075 Pa.s) and water. For the high viscosity oil, OLGA was reported to have given a good prediction of the pressure gradient and hold up to a superficial gas velocity of 2.5 m/s beyond which the flow code failed to predict observed flow patterns and measured flow variables. OLGA was also noted to provide a good prediction of the measured flow variables when simulations were run under dynamic conditions with "Slug Tracking Model".

Sannæs and Johnson, (2010), compared slug and wave characteristics of two-phase oil-gas slug flow for a high-pressure system obtained from Statoil test facility with OLGA multiphase flow simulator. The facility's test section consists of a 200 m long duplex steel pipe with an Internal Diameter of 0.078 m. oil viscosities used were 0.033 Pa.s and 0.165 Pa.s. The low and high viscous experiments were carried out at 50 barg and 10 barg respectively. OLGA was observed to over predict the hydrodynamic slugging region for high-pressure experiments in the low superficial velocity range while it under predicted at the low-pressure region. The evidence from the review indicates that existing literature is limited to the experimental dataset for oil-gas flows with viscosities greater than 0.7 Pa.s.

2 RESEARCH METHODOLOGY

The hydrodynamics of two-phase flow is investigated using the OLGA software. OLGA is an integral part of Schlumberger Limited and is the world's largest oilfield services company. It is a modelling tool for multiphase transport of oil, gas and water through pipelines, and is established as a world leading product in this field.

To achieve a simulation process, a PVT-sim software program developed by Calsep Limited was used to define the fluid package for this study. PVT-Sim is a versatile simulation software that was developed for petroleum engineers to calculate and process the physical properties of crude oil and natural gas. From OLGA-simulations, data for two-phase flow parameters such as pressure gradient and two-phase flow liquid holdup were obtained. Specifications were defined for the case setup such as pipe length, inner pipe diameter, roughness and flow rates corresponding to the operating conditions of the experimental data acquired from Cranfield University's Oil and Gas Engineering Centre, United Kingdom. Presented in Figure 2 is the interphase for OLGA Flow Simulator. The flow conditions executed for this study is presented in Table 1.

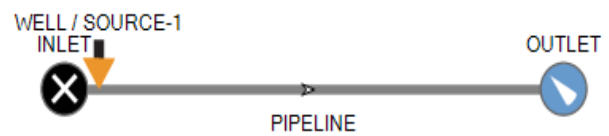


Fig. 2: OLGA Flow Simulator Interface

The multiphase flow facility is fabricated from a 5.5 m long; 0.0765-m Internal Diameter Perspex pipe located at the Oil and Gas Engineering Centre of Cranfield University, United Kingdom was used for the experimental study. The test facility has an observation section with measuring instruments placed at a distance of at least 60 pipe diameters from the last injection point.

A screw compressor manufactured by Anglian Compressors with maximum discharge pressure of 10 barg and a maximum capacity of 400 m³/hr receives free air and compresses it before supplying to the flow loop. CYL680 mineral oil manufactured by Total Limited, UK was used as the test fluid. The oil is stored in a 0.15 m³ tank capacity manufactured from plastic material and insulated with fibres on the periphery. A variable speed PCP with maximum capacity, 0.72 m³/hr, is used in pumping oil. An Electrical Capacitance Tomography (ECT) device manufactured by Industrial Tomography Systems (ITS), Manchester, UK was used for the measurement of the mean liquid holdup. The system is made up of a sensing unit, data acquisition and a computing system. A differential pressure transducer, Honeywell STD120, with minimum pressure drop measurement of 100 Pa and an accuracy of $\pm 0.05\%$ is used to measure the differential pressure. The temperature of the test fluids on the test section is measured using J-type thermocouples.

Table 1 Flow Conditions and Specification

Parameters	Conditions
Pipe diameter	0.0765m
Pipe length	14m
Pipe roughness	0.02m
Superficial Gas Velocity	0.3 to 9m/s
Superficial Liquid Velocity	0.06 to 0.3m/s.

3 RESULTS AND DISCUSSION

OLGA 7.3.1 Multiphase Flow Toolkit was used to simulate the experimental test conditions. Results extracted from the OLGA Toolkit were subsequently compared to experimental measurements.

3.1 MEAN LIQUID HOLDUP

Figure 3 shows a plot of the measured liquid holdup, and the liquid holdup predicted by OLGA's software plotted as a function of the superficial gas velocity for different superficial oil velocities and viscosities. For all the flow conditions studied, mean liquid holdup predicted by the OLGA software consistently underestimates the measured liquid holdup. This can be attributed to inherent models used by the software which were developed based on observation from low viscosity liquid.

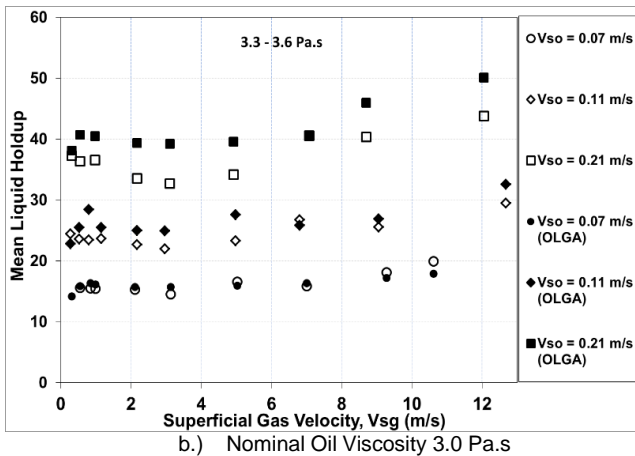
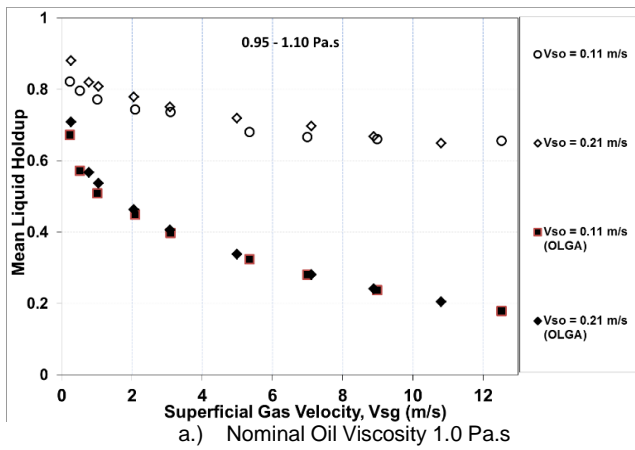


Fig. 3: (a-b): Comparison of Mean Liquid Holdup Measured in Experiments and OLGA Multiphase Flow Toolkit.

3.2 PRESSURE GRADIENT

Plots of the measured pressure gradients and the pressure gradients predicted by the OLGA software as a function of gas superficial velocities at different oil superficial velocities and viscosities are shown in Figure 4 below. The Results show that the pressure gradient values predicted by the OLGA software were good at relatively lower oil viscosities, the largest variations from the predicted pressure gradient are observed at nominal oil viscosity of 5.0 Pa.s. OLGA's prediction trend may be influenced by the closure relationships used in the pressure gradient model most of which may have been developed based on relatively lower viscous oil flow characteristics.

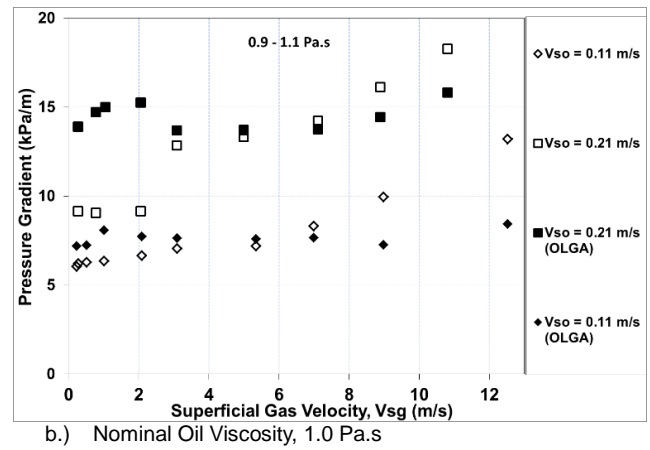
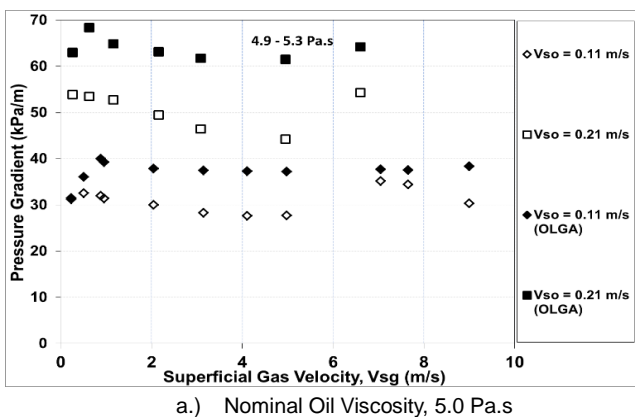


Fig. 4: (a)-(b): Comparison of Mean Liquid Holdup Measured in Experiments and OLGA Multiphase Flow Toolkit.

4 CONCLUSION

Comparison between experimental measurements and OLGA software predictions have been carried out. Results obtained showed that OLGA predictions decreased with increasing superficial gas velocity and generally underestimated the measured mean liquid holdup. For pressure gradient, OLGA's predictions increases with an increase in superficial gas velocity and viscosity attributed increase around the pipe walls. The prediction was found to have a relatively good match with measured pressure gradient with its predictive capability reducing with an increase in oil viscosity.

List of Abbreviations

V_{so}	Superficial Oil Velocity	m/s
V_{sg}	Superficial Gas Velocity	m/s
ID	Internal Diameter	m
Pa.s	Pascal second	

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