A Simple Model for Predicting the Two-Phase Heavy Crude Oil Horizontal Flow with Low Gas Fraction

Xiao-Ping Chen, Jing-Yu Xu & Jian Zhang

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XIAO-PING CHEN, JING-YU XU, and JIAN ZHANG

Key Laboratory for Mechanics in Fluid Solid Coupling Systems, Institute of Mechanics, Chinese Academy of Sciences, Beijing, China

A two-phase heavy crude oil flow with low gas fraction is common in the oil transportation process. However, most of the studies of a gas–liquid flow are based on low viscosity fluid, such as water and light oil; as a result, the results cannot be introduced successfully into the mixture flow of gas and heavy crude oil. In this work, a two-phase flow of gas and heavy crude oil, which originated from the Bo-hai oilfield in China, was investigated in a horizontal pipe with 47-mm inner diameter. Data were acquired for the oil flow rate ranging from $2\,m^3/h$ to $10\,m^3/h$, the input gas volume fraction ranging from 0.01 to 0.15, and the viscosity of crude oil ranging from 2.41 Pa·s to 0.34 Pa·s. Based on the drift-flux model, a new simplified correlation was developed to predict the void fraction and the pressure gradient. A comparison between the predicted and measured data demonstrates a reasonable agreement, and the correlation might be helpful for practical application in industry, especially in initially estimating the flow characteristic parameters.

Keywords: Drift-flux model; Gas–liquid flow; Heavy crude oil; Pressure gradient; Viscosity; Void fraction

Introduction

Heavy crude oil is any type of crude oil which does not flow easily with the lower value of API from 10° to 20° and greater viscosity (Keleşoğlu et al., 2012; Rafael et al., 2011). With the production of heavy crude oil increasing year by year, research studies on pipeline transportation are attracting increased attention. Currently, studies of heavy crude oil in pipe flow primarily focus on the drag reduction and the rheological properties of emulsions (Ashrafizadeh and Kamran, 2010; Ghannam et al., 2012; Keleşoğlu et al., 2012; Zhang et al., 2014). In addition, because the produced fluids in a well contain gas, the gas and crude oil two-phase flow also attracts the attention of several scholars. However, unlike the mixture flow of gas and low viscosity liquid, such as water or light oil, investigations of the two-phase flow of gas and heavy crude oil are notably rare.

Gokcal et al. (2008) studied the influences of high oil viscosity on flow pattern, pressure gradient, and liquid holdup in a gas–liquid horizontal flow. Oil viscosities in the range from 0.181 Pa·s to 0.587 Pa·s were investigated by changing the oil temperature. Flow pattern regimes were compared with the Barnea (1987) flow pattern model and the Zhang et al. (2003) model, respectively. Liquid holdup and pressure drop were predicted by the Zhang et al. (2003) model and the Xiao (1990) model. The results showed that the existing models needed to be modified or new models should be

developed owing to the high oil viscosity. Foletti et al. (2011) investigated an air and oil two-phase flow in a horizontal pipe with the oil viscosity 0.896 Pa·s. Experimental results were compared with the flow pattern maps such as Baker (1954), Mandhane et al. (1974), and Petalas and Aziz (1998). The conclusions revealed that these flow maps failed to predict the data, and current models were unable to predict the flow features satisfactorily.

Matsubara and Naito (2011) investigated the effects of liquid viscosity on flow pattern in a 20-mm transparent pipe. The liquid viscosities changed from 0.001 Pa·s to 1.1 Pa·s. Similar to the previous research, the effect was significant with the viscosity higher than 0.1 Pa·s. With the increase of liquid velocity, the regions of roll wave flow and stratified flow were replaced by those of annular flow and intermittent flow, respectively. Recently, Zhao et al. (2013) performed experiments in a horizontal pipe with an inner diameter of 26 mm. A range of liquid viscosity from 1.0 Pa·s to 7.5 Pa·s was investigated. It was found that the Beggs and Brill (1973) flow regime map gave an acceptable prediction when the liquid viscosity was in the range from 1.0 Pa·s to 3.5 Pa·s, and yet became unreliable when the liquid viscosity exceeded 3.5 Pa·s.

Based on the abovementioned literature survey, it can be concluded that the available data on two-phase flow with heavy crude oil are scarce and the mechanisms behind it remain unclear. In other words, the research results are far from systematic and perfect for the mixture flow of a gas and heavy crude oil. Therefore, further studies on the topic are urgent and helpful to provide an accurate design of pipeline transportation in the petroleum industry. The purpose of this work is to investigate the two-phase heavy

Address correspondence to Jing-Yu Xu, Key Laboratory for Mechanics in Fluid Solid Coupling Systems, Institute of Mechanics, Chinese Academy of Sciences, Beijing 100190, China. E-mail: xujingyu@imech.ac.cn

crude oil horizontal flow with low gas fraction. Special attention is placed on the influence of the oil phase viscosity on the pressure gradient and the void fraction. In pipe flow experiments, the heavy oil viscosity was changed by adjusting the temperature. In addition, a simple relationship was determined for calculating the void fraction and the pressure gradient that develops in an intermittent two-phase heavy crude oil horizontal flow.

Experimental Set-Up and Procedure

Rheological Measurements

The heavy crude oil used in this work came from the Bo-hai oilfield in China. Prior to the pipe flow experiments, rheological measurements were performed on the Haake RS6000 Rheometer with a coaxial cylinder sensor system (Z38 DIN, gap width = 2.5 mm and sample volume of 30.8 cm^3). The resolution ratio of torque and angular displacement of the rheometer are 0.5 μNm and 12 μrad, respectively, and the maximum relative error of viscosity measuring is ± 0.5% % at shear rates from 0.1 s^{-1} to 1000s^{-1}. In the rheometer, a temperature control system for cone and plate measuring geometries and two units with different coaxial cylinder diameters is available. The liquid temperature-controlled unit can make the sensor system reach a fixed temperature and maintain this temperature throughout the experiment. Three replicates of each test were performed and the average viscosities were adopted. Furthermore, the rheometer has a range of shear rates from 0.001 s^{-1} to 1000s^{-1} and a range of viscosity from 0.001 Pa·s to 1000 Pa·s.

Pipe Flow Experiments

A schematic view of the flow loop is shown in Figure 1. In this loop, the pipe with 47-mm inner diameter and total length of 15 m was made of stainless steel. The air came from a compressor, and heavy crude oil was conveyed from oil tank into the pipeline. Both air and crude oil were fed into the pipeline via a T-junction. The volumetric flow rates of both phases could be regulated independently and were measured using a mass flow meter for the air phase and a

turbine flow meter for the oil phase. The maximum error of air flow meter was ±1.5% of its full scale, and the oil flow meter ±0.5%. The pressure gradient was measured by a differential pressure transducer, which was made by Rosemount named 3051CD. The maximum error for all test points within the measurement range was ±0.75% of the full scale (60 kPa/m). A Coriolis mass flow meter (Micro Motion F050 from Emerson) was used to monitor the void fraction, temperature, and mass flow rate of the mixture flow.

In the present study, the viscosity of the heavy crude oil was changed by adjusting the temperature, which was governed by the heating system in the oil tank. Before the tests, the flow loop was filled with heavy crude oil at a constant temperature. Next, the heat cable wrapped around the stainless steel tube was used to maintain the balance between the frictional heat generation and the pipe wall heat transfer. Here, there were two factors affecting the temperature's constant of the flowing liquid. One was the heat generation caused by the friction which made the temperature higher, the other was the heat transfer through the tube wall to the environment which made the temperature lower. In fact, the above two factors were unlikely to achieve a balance by chance. Therefore, an electric heating cable was wrapped around the tube to keep the flowing oil temperature constant. When the oil temperature in the flow loop was lower than the fixed temperature, the cable would work; otherwise, it was powered off. Using those two devices, a large range of viscosities could be obtained from 2.41 Pa·s at 40°C to 0.34 Pa·s at 68°C. In this instance, the flow rates of the oil phase were 2 m^3/h, 4 m^3/h, 6 m^3/h, 8 m^3/h, and 10 m^3/h. In addition, the input gas volume fraction was adjusted from 0.01 to 0.15 at a step of 1%.

Results and Analysis

Single Phase Flow

The flow behaviors of heavy crude oil were investigated over a wide range of shear rates from 0 to 200 s^{-1} at different temperatures. The measurements were performed under the CR model, from which the shear rate was set and the corresponding shear stress obtained. Figure 2 gives the
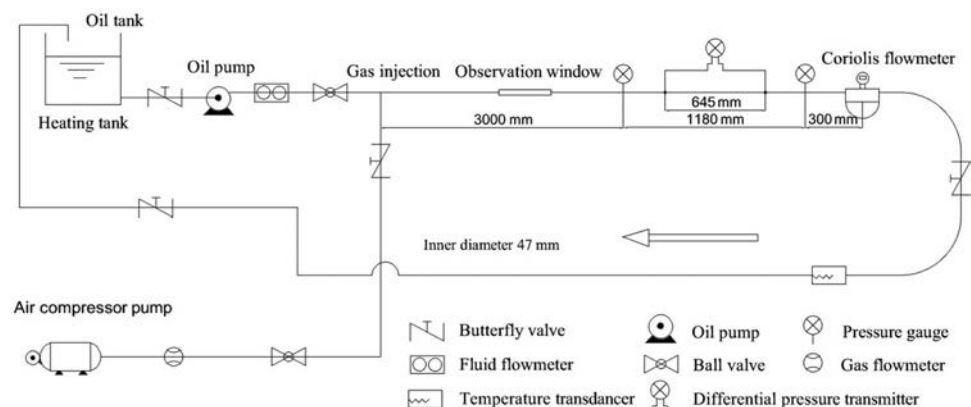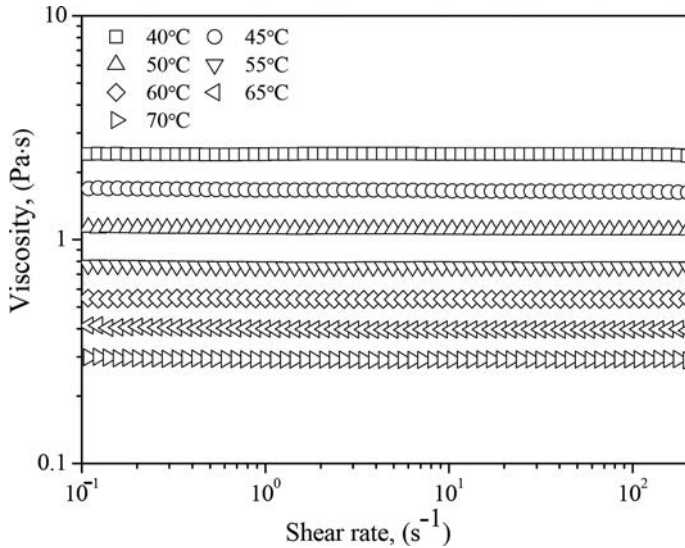

Fig. 1. Schematic view of the flow loop.

Fig. 2. Rheograms of the heavy crude oil at different temperatures.

Fig. 3. Comparison between the viscosities calculated from the pipe flow and those measured in the rheometer.

viscosity of heavy crude oil against the shear rate at a fixed temperature. No significant changes with shear rate are found for each temperature, i.e., each of the samples can be assumed to be a Newtonian fluid. In addition, the viscosity is observed to increase significantly with decreasing temperature under the same shear rate.

In a laminar pipe flow, the viscosity of heavy crude oil can be back-calculated from the frictional pressure gradient as

$$\mu = \frac{\Delta P}{L} \frac{\pi D^4}{128Q} \tag{1}$$

where $\Delta P/L$ is the frictional pressure gradient. D and Q refer to the diameter of the pipe and the flow rate, respectively. The viscosities calculated by using the data in pipe flow are compared with those measured in the rheometer, as shown in Figure 3. It can be observed that the viscosities show an exponential decrease with increasing the temperature. A good agreement is obtained between the two systems. The following equation is used to fit the viscosity–temperature data as

$$\mu = A\mathrm{e}^{B/T} \tag{2}$$

where A and B are parameters. μ and T refer to the viscosity and the absolute temperature, respectively. A fitting degree of $R^2 = 0.98$ shows that the equation can be well used for predicting the viscosity of heavy crude oil.

Two-Phase Flow with Low Gas Fraction

Most methods for predicting the flow patterns are suitable for the gas and light oil flow. In contrast, very little information for the gas and heavy crude oil flow is available. In this work, the flow patterns are determined mainly by using the previous conclusions in the literature (Zhao et al., 2013)
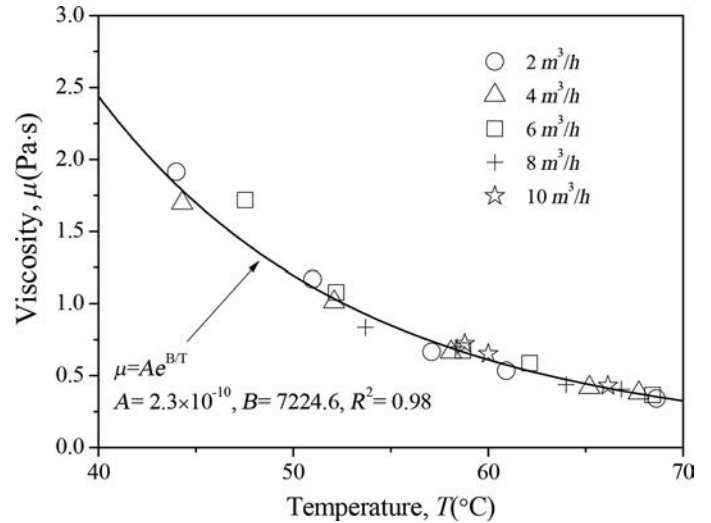
and visual observation. Figure 4 depicts the comparison between the data in this work and the flow pattern map of Chhabra and Richardson (1984). All of the flow patterns are observed to be intermittent flow. Under the same input conditions, similar results are also obtained in the studies of Gokcal et al. (2008).

In the experiments, the void fraction was calculated according to the mixture density measured via the Coriolis mass flow meter. It is well known that the measurement of two-phase flow by Coriolis mass flow meter is still a developing technique due to the complexity of two-phase flow. Based on the work of Henry et al. (2006), the measuring errors vary most notably with void fraction and liquid flow rate. Neural networks can be used to correct the measurement results based on internally observed
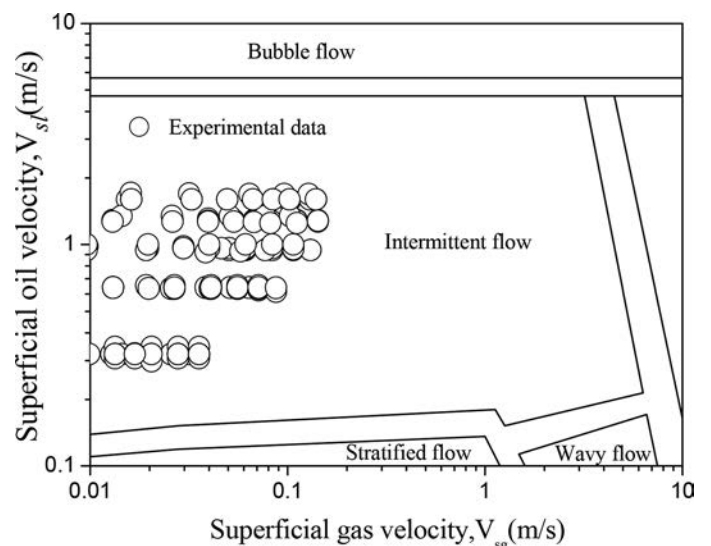

Fig. 4. Comparison of the data with the flow pattern map of Chhabra and Richardson (1984).

parameters, keeping the errors to within 2% (Liu et al., 2001). Thus, in the present study the following relative error (E_r) is defined to evaluate the accuracy of the Coriolis mass flow meter as

$$\mathrm{E_r} = \frac{Q_{g\text{-}cal} - Q_{g\text{-}input}}{Q_{g\text{-}input}}\% \tag{3}$$

where $Q_{g\text{-}input}$ is the input gas flow rate, $Q_{g\text{-}cal.}$ refers to the gas flow rate calculated by Coriolis flow meter based on a homogeneous hypothesis. Thirty groups of data were selected randomly and then the relative errors were calculated. The results show that the maximum and minimum relative errors are 16.83% and −13.42%, respectively. An average relative error of 0.82% shows that the measurement results are satisfied for this study.

Figure 5 shows the gas velocity against mixture velocity at different input gas fractions of 0.02, 0.04, 0.06, 0.08, and 0.10. In the figure, the gas velocity is calculated as the superficial gas velocity divided by the void fraction measured, and the drift-flux model is used to analyze the experimental data as
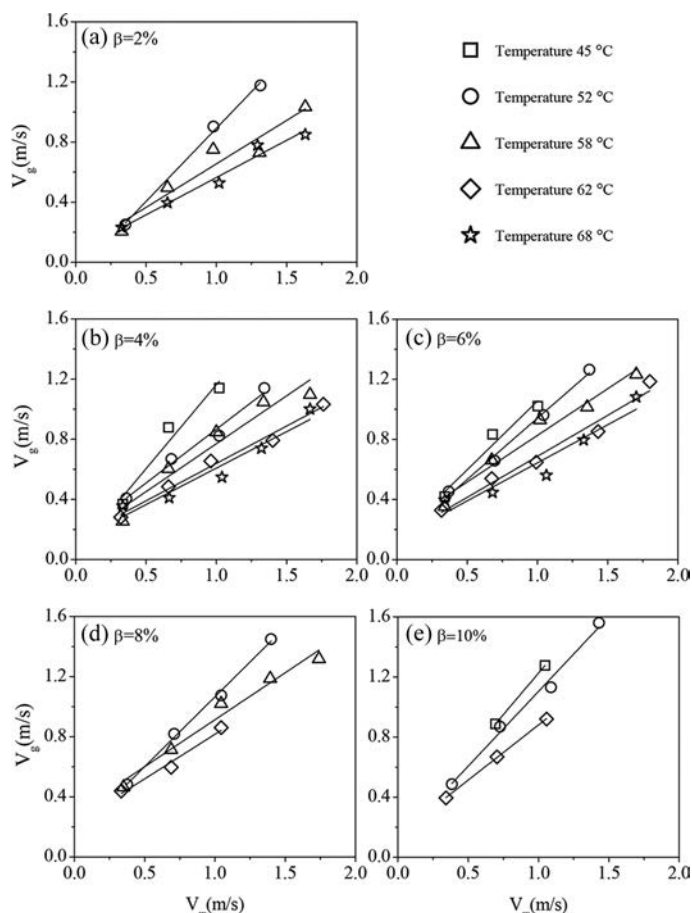
$$V_g = C_0 \times V_m + V_d \tag{4}$$

Fig. 5. Gas velocity versus mixture velocity at different input gas volume fractions.

where C_0 describes the effects of the non-uniform distribution of both velocity and concentration profiles. V_d is called the drift velocity and accounts for the local relative velocity between two phases. The least squares method is used to fit the experimental data, and the results are shown in Table I. From the table, once the input gas fraction is fixed, C_0 is observed to gradually reduce from 1.01 to 0.45 with increasing the temperature. Moreover, all V_d in the gas and heavy crude oil flow are smaller than those in the gas and water flow.

Figure 6 presents the change of the drift velocity with the reciprocal of the dimensionless Archimedes number at a fixed input gas fraction. The Archimedes number is applied to include viscosity, surface tension, fluid properties, and gravitational acceleration parameters; N_{Ar} is defined as (Wallis, 1969)

$$N_{Ar} = \frac{\sigma \rho_L}{\left[\mu_L^4 g(\rho_L - \rho_G)\right]^{0.5}} \tag{5}$$

where σ is the surface tension, and ρ is the density. The subscripts G and L refer to the gas phase and liquid phase, respectively. The experimental data are collected from this work and those in the work of Gokcal et al. (2009). As shown in the figure, the drift velocity decreases rapidly with increasing $1/N_{Ar}$ and then maintains an approximately constant value of 0.127. Here, V_d takes the maximum value of 0.35 when the liquid phase is water. In view of Figure 6, V_d can be determined by an exponential fitting as

$$V_d = A_1 + B_1 \times e^{\frac{C_1}{N_{Ar}}} \tag{6}$$

where A_1, B_1, and C_1 are constants which are obtained by fitting the data.

Figure 7 shows the gas velocity versus the mixture velocity at a fixed temperature. Similar to Figure 6, the least squares method is also used to fit the experimental data. Here, V_d is calculated by using Equation (6). The results, the change of C_0 with heavy crude oil viscosity, are shown in Figure 8. Unlike the case of C_0 as a constant of 1.2 for the gas and water flow, C_0 in the gas and heavy crude oil flow decreases from 1.01 to 0.45 with increasing the liquid phase viscosity. An exponential fitting of the relationship between C_0 and heavy crude viscosity is given as

$$C_0 = A_2 + B_2 \times e^{C_2 \cdot \mu_o} \tag{7}$$

where μ_o is the viscosity of the heavy crude oil.

Because the heavy oil viscosity is a function of temperature described by Equation (2), C_0 can be calculated by introducing Equation (2) into Equation (7). Thus, in a two-phase heavy crude oil horizontal flow with low gas fraction, the gas velocity can be obtained by Equations (4), (6), and (7). Once the gas velocity is acquired, the void fraction can be calculated by

Table I. C_0 and V_d at different temperatures with a fixed input gas fraction

T (°C)	$\beta = 2\%$		$\beta = 4\%$		$\beta = 6\%$		$\beta = 8\%$		$\beta = 10\%$	
	C_0	V_d	C_0	V_d	C_0	V_d	C_0	V_d	C_0	V_d
45	–	–	1.12	0.04	0.91	0.14	–	–	1.10	0.12
52	0.97	0.08	0.72	0.15	0.82	0.13	0.93	0.14	0.99	0.11
58	0.58	0.08	0.64	0.13	0.62	0.21	0.62	0.29	–	–
62	–	–	0.50	0.14	0.55	0.14	0.59	0.22	0.73	0.15
68	0.50	0.07	0.49	0.12	0.51	0.14	–	–	–	–

$$\alpha_g = \frac{V_{sg}}{V_g} \qquad (8)$$

where V_{sg} is the superficial gas velocity.

It can be seen from the above equations that only parameters such as V_{sg}, μ, ρ, and σ are needed for the void fraction calculation. There are no other adjustable parameters so that the calculation process is simple. Moreover, both V_d and C_0 are obtained at a viscosity range from 0.34 Pa·s to 2.41 Pa·s, and therefore the proposed model can be used at a wide range of viscosity. Figure 9 depicts a typical comparison between the experimental results and the prediction of the proposed methods. It can be found that the deviations in most cases are less than 20%, and the fitting results are within an average absolute error of 0.27%. In addition, the two-phase friction factors are also back-calculated from the frictional pressure gradient measured, as shown in Figure 10. In this figure, the mixture Reynolds numbers are obtained by the homogeneous hypothesis, and Equation (8) is used to determine the mixture density and the mixture viscosity. It can be found that the experimental friction factors show a good agreement with the Poiseuille relations. Furthermore, the data acquired by Gokcal et al. (2008)

were also used to validate the model. In their work, there are four appropriate points within an input gas fraction less than 20%. A comparison between the data measured and those predicted by the model is shown in Figure 11. Here, the maximum relative error is about −11%. The predicted results would be acceptable according to the potential measurement errors at low gas fraction by Gokcal et al. (2008).

In order to further verify the feasibility of the proposed model, the software package of PIPESIM is used to analyze the experimental data. In the simulation process, the API of heavy oil is set as 13.3, the Hossain model is adopted to
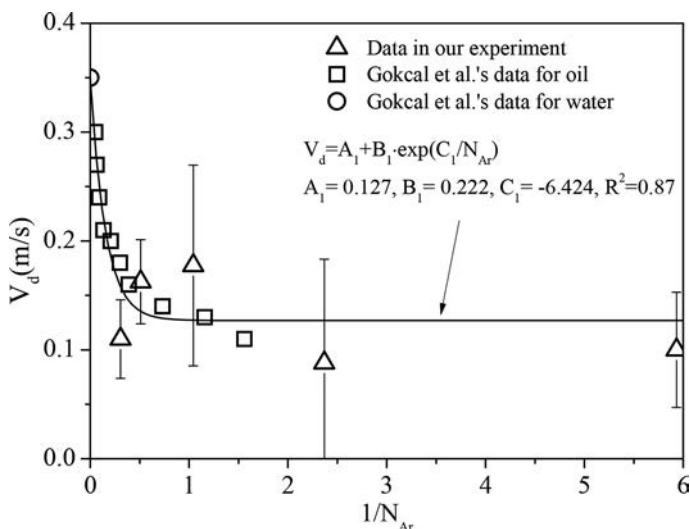

Fig. 6. Drift velocity versus reciprocal of the dimensionless Archimedes number.
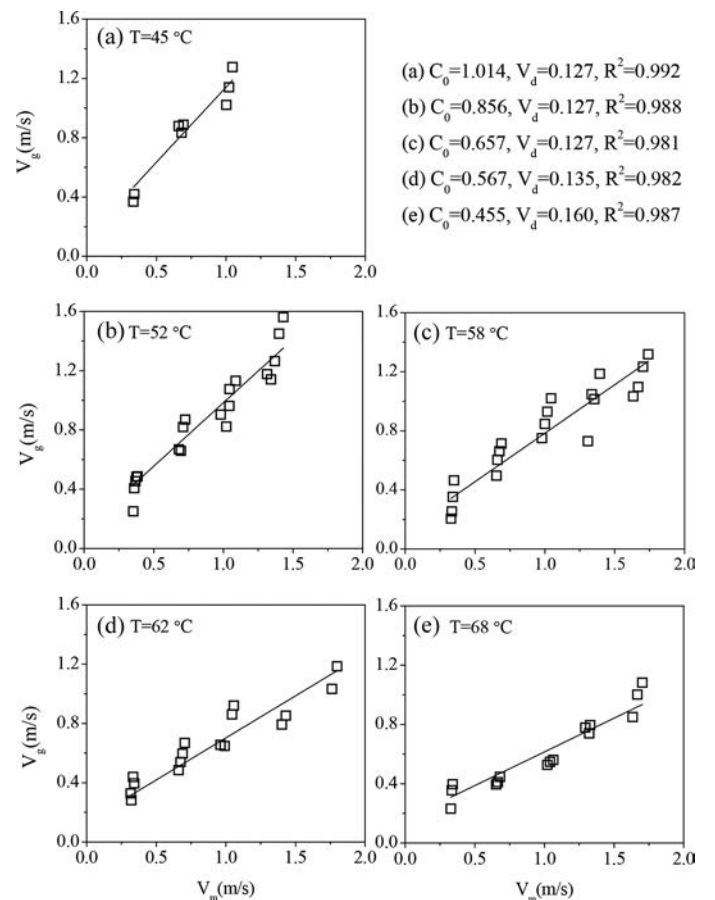

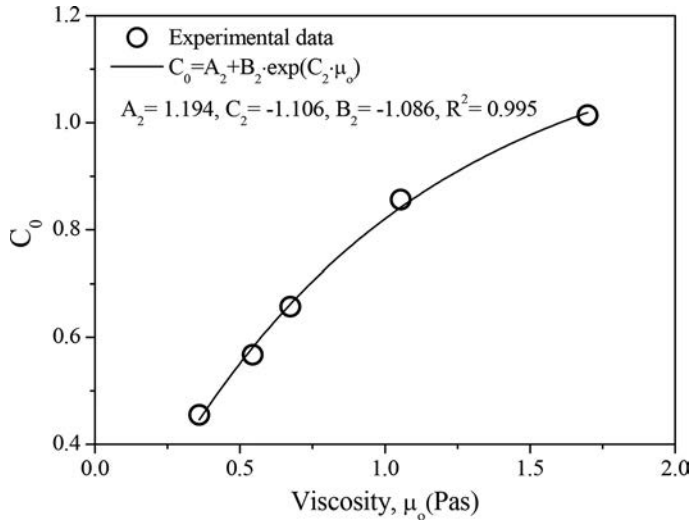**Fig. 7.** Gas velocity versus mixture velocity at different temperatures.

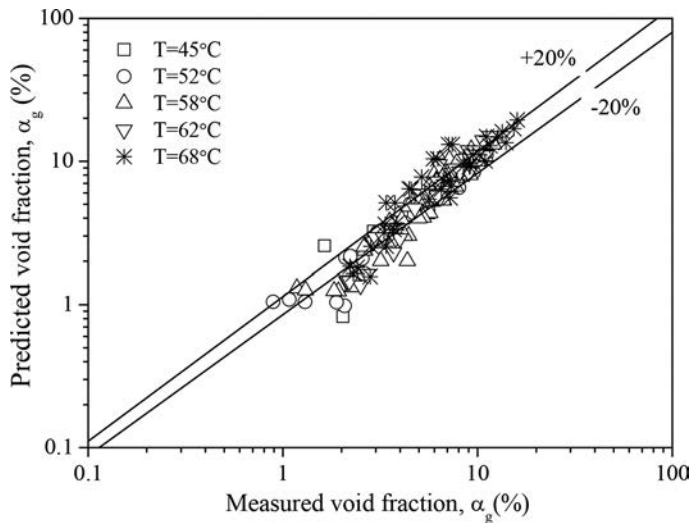**Fig. 8.** Change of C_0 with the heavy crude oil viscosity.

Fig. 9. Comparison between the void fractions predicted and those measured in the pipe flow.
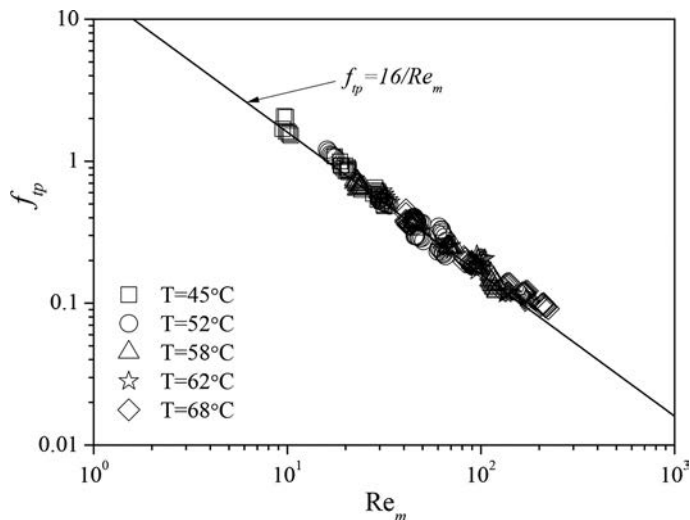

Fig. 10. Two-phase friction factors measured versus mixture Reynolds calculated by the suggested correlation.
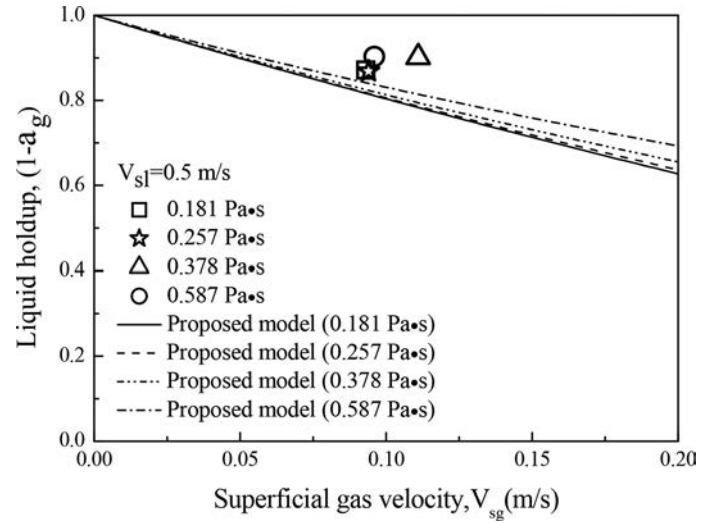

Fig. 11. Comparison between the liquid holdups predicted and those measured in Gokcal's work.

calculate the oil viscosity and the relationship of Beggs and Brill selected as the multiphase flow correlation. Figure 12 shows the comparison between the void fraction by PIPE-SIM software and those obtained by the proposed model. It can be seen that the deviations by PIPESIM software are between -20% and -40%. Figure 13 gives the comparison of two-phase pressure drop. Similar results can be found that the proposed model is more accurate than PIPESIM software. It might be due to the fact that the multiphase flow correlation in PIPESIM software are usually established based on a gas/low viscosity liquid flow such as water or light oil.
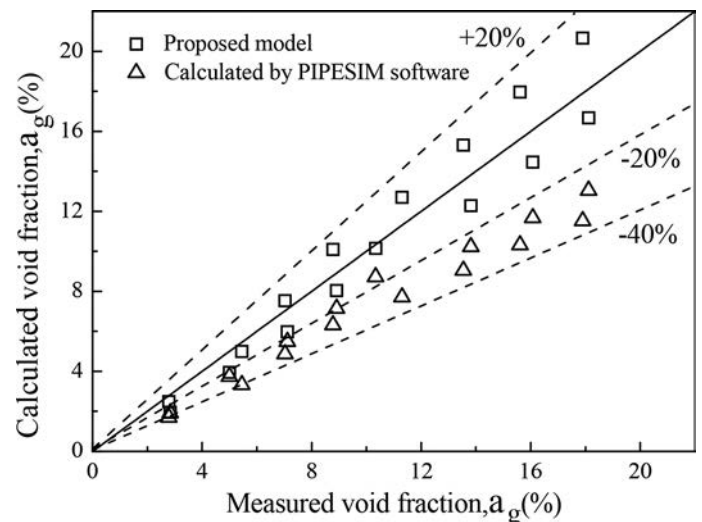

Fig. 12. Comparison between the void fraction by PIPESIM software and those obtained by the proposed model.
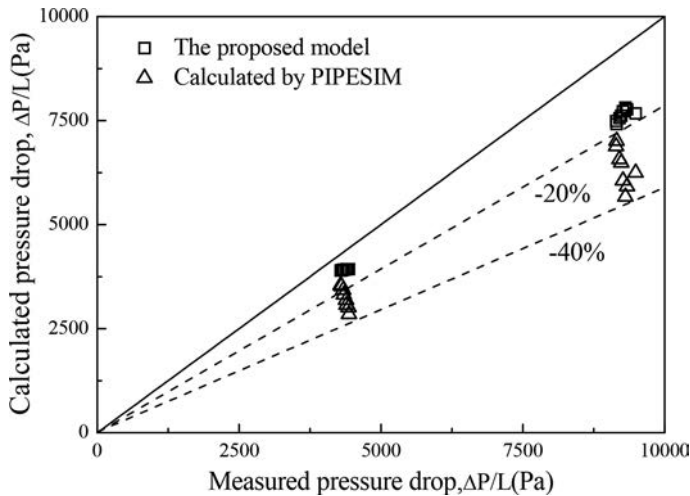
Fig. 13. Comparison between the pressure drop by PIPESIM software and those obtained by the proposed model.

Conclusions

In this work, we provided a valuable data set of the two-phase heavy crude oil horizontal flow with low gas fraction. Data were acquired for the oil flow rate from $2\,m^3/h$ to $10\,m^3/h$, and the input gas volume fraction from 0.01 to 0.15. The heavy oil viscosity ranged from 2.41 Pa·s to 0.34 Pa·s by adjusting the temperature from 40°C to 68°C. The void fraction and the pressure gradient were measured and analyzed.

Flow behaviors of heavy crude oil were investigated under different temperatures, and an exponential equation was used to fit the viscosity–temperature data well. For gas and heavy crude oil two-phase intermittent flows, the flow patterns were determined by using the previous conclusions in literature and visual observation. A simplified correlation was developed in order to fit the available data of gas and heavy crude oil intermittent flow based on the drift-flux model. In this correlation, C_0 is predicted by an exponential relationship with the heavy crude viscosity, and V_d obtained by an exponential relationship with the dimensionless Archimedes number.

The proposed model was validated against a set of available experimental data in this work and those in literature. Comparison between the predicted and measured data revealed a reasonable agreement. Furthermore, the software package of PIPESIM was also used to analyze the experimental data. The results showed that the proposed model was more accurate than PIPESIM software. Considering that a more accurate prediction in the gas and heavy crude oil flow is highly complicated and difficult, the correlation suggested might be helpful for practical application in industry, especially for initially estimating the void fraction and pressure gradient.

Nomenclature

$\Delta P/L$	Frictional pressure drop, Pa/m
Q	Flow rate, m³/h
D	Pipe diameter, m
T	Temperature, °C
C_0	Distribution parameter
V_d	Drift velocity, m/s
V_g	Real gas velocity, m/s
V_m	Mixture velocity, m/s
g	Gravitational acceleration, m²/s
V_{sg}	Superficial gas velocity, m/s
N_{Ar}	Archimedes number
f_{tp}	Friction factor
Re_m	Mixture Reynolds

Greek Letters

μ	Viscosity, Pa·s
σ	Surface tension, N/m
ρ_L	Density of the liquid, kg/m³
ρ_G	Density of the gas, kg/m³
μ_o	Viscosity of the oil, Pa·s
α_g	Void fraction

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