AN INVERTED FLOW PATTERN DEPENDENT MODEL FOR HORIZONTAL AND INCLINED OIL-WATER WELL LOGGING

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Abstract. *Production logging is one of the most important aspects of managing oil/gas production of a field. It provides insight into the type and rates of fluid flow in the reservoir, which is critical to optimizing the life of the well. In multiphase oil production logging one would like to derive, from limited down-hole information on pressure loss and phase holdup, the oil and water production rates one can expect in near-horizontal tubing. A study based on the flow pattern prediction model developed by Trallero (1995) was carried out in order to investigate flow-pattern transitions, holdup and pressure gradient in oil-water flows. The steady-state one-dimensional two-fluid model for stratified flow and the homogeneous model for dispersed flow were used for holdup and pressure gradient prediction. A comparison of theoretical results with very recently published experimental data for horizontal and inclined pipes covering a significant range of pipe sizes was performed and the agreement was satisfactory. Subsequently, the oil and water superficial velocities were calculated from pressure drop and holdup data through the herein proposed inverse mode prediction technique. The agreement with experimental data is quite satisfactory. New oil-water experimental data on large diameter inclined pipe flow colected at the facilities of the Shell Exploration and Production B.V., Rijswijk, are presented.*

Keywords*: Oil-water flow, Production rates, Large inclined pipe flow, Inverse modelling, Two-phase pressure loss*

1. Introduction

In multiphase oil/gas production logging analysis one would like to derive, from limited down-hole information on pressure loss and phase holdup, the oil, gas and water production rates one can expect in tubing at angles from horizontal up to vertical. The aim of this work is to address this question for two-phase oil-water flow as a starting point for the more complex three-phase flow problem. A flow pattern dependent model has been chosen as modelling approach, since for the gas-liquid flow it has proven to be the most reliable method to calculate two-phase pressure gradient and holdup. In that sense, a suitable liquid-liquid flow pattern prediction model must be used together with appropriated holdup and pressure gradient models in an inverted mode so as to calculate the flow rates. By crossing holdup and pressure gradient information, it should be possible to find a solution that could be correlated with the flow pattern and correspondent superficial velocities of the phases. Multiple solutions are expected in this kind of approach, since it is not a well-posed problem, however considering the practical application the range of solutions may be sufficiently small so that a reliable estimation of the flow rates can be ensured.

Methods for calculating the pressure drop and the volumetric fractions of the phases in pipelines have been presented, which require a correct prediction of the flow patterns (Nadler and Mewes, 1997, and Angeli and Hewitt, 1998). The pipe flow of two-phase oil-water mixtures may form several flow patterns of the two phases and. By analogy with gas-liquid mixtures, these can be grouped into three categories: dispersed flow, separated flow and intermittent flow, (Bannwart *et al.*, 2004). Observations of all these flow patterns in a single apparatus depends on the fluid properties, pipe size and geometry involved (Charles *et al.*,1961, Flores *et al.*, 1997, Trallero *et al.*, 1995 and 1997). In a recent paper, Sotgia, and Tartarini (2001) presented a study about the state of the art in horizontal oil-water flow (including viscous oils) and showed that there are still many discrepancies in two-phase pressure drop prediction. Even for the relatively simple case when the oil viscosity is only a few times higher than water, there is not a definitive model or correlation for predicting the two-phase pressure drop (also: Angeli and Hewitt, 1998, Valle and Utvik, 1997, and Lovick, and Angeli, 2001).

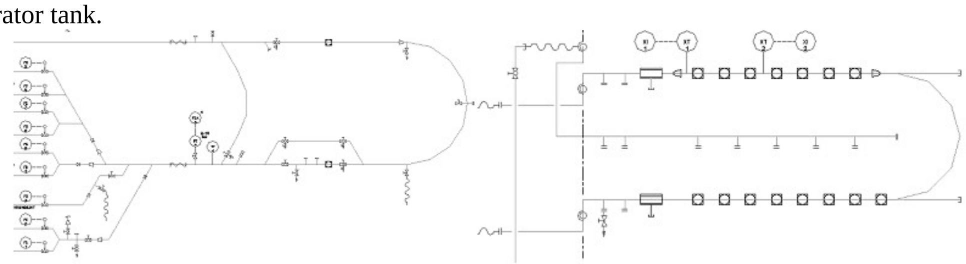
A few works deal with modeling of flow pattern transitions in liquid-liquid systems. The transition from stratified flow in horizontal liquid-liquid flow has been predicted by the so-called zero-neutral-stability (ZNS) condition and the zero-real-characteristics (ZRC) condition (Brauner and Maron, 1992a and 1992b) as well as by the inviscid Kelvin-Helmholtz (IKH) analysis and the viscous Kelvin-Helmholtz (VKH) analysis (Trallero, 1995). The one-dimensional wave model for incompressible flow also provides similar transition conditions, but for gas-liquid flow (Crowley *et al.*, 1992 and 1993). Recently, Rodriguez and Bannwart (2004) investigated the transition from annular flow to slug flow in high-viscosity-ratio liquid-liquid flow based on the one-dimensional wave theory.

The very common occurrence of multiphase flow in pipes has motivated an extensive investigation on the field over the last years. However, there is still a lack of multiphase flow data in large diameter inclined pipes. Particularly, the oil-water data at disposal are rather scarce. A few recent works have presented larger diameter data on oil-water flow (Trallero, 1995, Alkaya *et al.*, 2000, Fairusov *et al.*, 2000, Elseth, 2001 and Oddie *et al.*, 2003, Lovick and Angeli, 2004). Unfortunately, none of these offer an adequate set of holdup and pressure gradient data as a function of the flow patterns in slightly inclined oil-water flow.

The experimental results reported in this work fill some of the gaps identified above. A set of liquid-liquid flow data was acquired in a horizontal and slightly inclined large steel pipe using mineral oil and brine. The following deviations from horizontal were studied: -5, -2, -1.5, +1, +2 and +5 degrees. The following data were collected for horizontal flow and for each one of the six deviations: two-phase pressure gradient, *in situ* volumetric fraction of the liquid phases (holdup) and on-line digital images of the flow, covering the entire range of flow rates.

2. Experimental Setup

The experiments reported in this paper were performed at the Multiphase Test Facility of Shell Exploration and Production B.V., Rijswijk. Both water (brine, averaged density of 1060 kg/m^3 and viscosity of 0.8 mPa.s) and oil (Shell Vitrea 10, averaged density of 830 kg/m^3 and viscosity of 7.5 mPa.s) were kept in the same large separator. At the 15 m-long test section there is a 1.15 m-long transparent Perspex (PMMA - polymethyl methacrylate) pipe section for visualizations. The large inclinable flow loop basically consists of the pipework represented in Fig. 1. A mixing section is responsible on the generation of the multiphase flow (Fig.1a). In between the mixing section and the test section a length of 250 i.d. is left for the two-phase flow development. The test section (Fig.1b) is fixed to a table that can be pneumatically deviated from 0^o (horizontal) to 90^o (upright). The direction of the flow can be inverted; therefore the entire range of uphill and downhill flows can be investigated. Finally, the oil-water flow is conveyed to a coalescent-element separator tank.



(a) (b)

Figure 1. Schematic view of the flow loop; (a) mixing section and (b) test section.

The instrumentation used in the experiments provided two types of data, the reference measurements of flow, deviation, density, viscosity, pressure and temperature, and the detailed measurements required to determine the holdup and two-phase pressure gradient. Electromagnetic and turbine flow meters, differential pressure diaphragm gauge (one arm connected to a reference pressure line), absolute pressure gauge and thermo-couples were part of the reference measurements instrumentation. Video recording was used for the flow patterns identification. The chosen technique for holdup measurements was the gamma-ray densitometry, which has been already successfully applied in oil-water flows (Elseth, 2001 and Oddie *et al.*, 2003). The gamma-ray densitometer measures the gamma beam absorption and allows the mean density of the mixture in the pipe to be calculated. One nuclear densitometer (Berthold LB 444) was installed at the beginning and another at the end of the test section to assess the full development of the two-phase flow. The mean density of the *in situ* mixture, ρ_m, is determined from the gamma densitometer count and the calibrations. The gamma densitometer measures vertically the water height, which is also a measure of water holdup for fully dispersed flow. However, for stratified flow a geometrical correction should be introduced to account for the phase distribution along the pipe curvature (Oddie *et al.*, 2003).

About 40 points were collected for each inclination (a point means a pair of oil and water superficial velocities or flow rates). The ranges of superficial velocities covered were $0.02 < U_{os}$ (oil) < 3.00 m/s and $0.02 < U_{ws}$ (water) < 2.55 m/s. Therefore, mixture velocities as low as 0.04 and as high as 5.55 m/s were accomplished. The experimental campaign collected 296 points. Additional 14 tests were repeated, so the total number of tests conducted was 310.

The data collected in this work were found to follow a Gaussian distribution with time. The reference measurements, which include single-phase flow rates, densities of the phases, pressures and temperatures, presented an uncertainty of 0.1% of range. Two-phase pressure gradient measurements presented an uncertainty of about 1% of range for most of the experiments. Higher experimental uncertainties were detected around dp/dz = 0, of the order of 350% or even higher, which made unfeasible the analysis of data in such circumstances. Regarding the water holdup measurements, uncertainties of the order of 1% of range were computed for most of the experiments. Higher uncertainties of the order of 10% were detected for the lowest holdups (< 0.10).

3. Holdup and pressure gradient models

The liquid-liquid flow-pattern prediction model proposed by Trallero (1995) was considered the most appropriated for this work. The models applied to holdup and pressure gradient predictions were the area-averaged steady-state one-dimensional two-fluid model for stratified flow and the homogeneous model for dispersed flow. The two-fluid model for stratified flow is applied to specific operating conditions, i.e. superficial velocities, fluid properties and pipe geometry. The flow parameters (actual velocities, holdup, etc.) are calculated from the combined momentum equation for steady-state flow. Thus, eliminating the pressure drop from the equations of each phase:

$$-\frac{\tau_w S_w}{A_w}+\frac{\tau_o S_o}{A_o}\pm\tau_i S_i\left(\frac{1}{A_w}+\frac{1}{A_o}\right)-(\rho_w-\rho_o)g\sin\theta=0 \tag{1}$$

where τ_x stands for the shear stress, S_x the wetted perimeter, A_x the cross sectional area, ρ_x the density and θ the inclination angle from the horizontal. Equation (1) is a non-linear equation which can be solved for the liquid level or holdup using a standard numerical method if the shear stresses are expressed in terms of known friction factors. The pressure gradient is then found by insertion into the either one-dimensional differential equations of momentum of oil or water. The homogeneous model for the pressure gradient in a liquid-liquid dispersion is often given as:

$$\frac{dp}{dx}=-\frac{f_{m,\mathrm{hom}}\rho_{m,\mathrm{hom}}U_m^2}{2D}-\rho_{m,\mathrm{hom}}g\sin\theta \tag{2}$$

where $f_{m,hom}$ is the mixture friction factor, $\rho_{m,hom}$ is the mixture density, U_m is the mixture velocity and D the pipe's internal diameter. The mixture parameters are basically treated as holdup-weighted relations. Further details can be found in Rodriguez *et al.* (2004).

4. Oil-water flow patterns

The oil-water flow patterns observed in this work suit very well the flow pattern classification proposed by Trallero (1995). The only difference is the Stratified Wavy (SW) flow pattern observed in downward and upward flow.

Table 1. Flow patterns observed

-Stratified Smooth	**ST**
-Stratified Wavy	**SW**
-Stratified flow with mixing at the interface	**ST & MI**
-Dispersion of oil in water and water	**Do/w & w**
-Oil in water emulsion	**o/w**
-Water in oil emulsion	**w/o**
-Dispersions of water in oil and oil in water	**Dw/o & Do/w**

The stratified and semi-stratified flow patterns: ST, SW, ST&MI and Do/w&w, and the oil-in-water (o/w) and water-in-oil (w/o) emulsions could be characterized by watching the recorded movies of the flow. Assuming that the homogeneous model represents very well the phases distribution for the fully-dispersed flow patterns, it would be possible to verify a relative deviation from the homogeneous behavior when comparing the holdup results of the w/o flow pattern with the results of the Dw/o&Do/w flow pattern. The relative deviation from the homogeneous behavior was quantified by comparing the experimental water holdup to that predicted by the homogeneous model. A detected change of trend, when increasing the water superficial velocity at the oil-dominated region, was considered as a suitable evidence of the existence of the Dw/o&Do/w flow pattern. Photographs of the flow patterns are shown in Fig. 2. With respect to the Stratified Wavy (SW) flow pattern, its most remarkable hydrodynamic feature is the stable wavy structure of the interface. No sign of dispersion at the interface was observed whatsoever. The SW flow pattern was observed in downward flow and upward flow.

Flow maps of water and oil superficial velocities were generated after the flow pattern characterization. Figure 4 shows experimental flow maps for horizontal, -2^o and -5^o downward and +5^o upward inclined flows (dots) together with the predictions of the flow pattern model (solid lines). The agreement in between the experimental flow map and that predicted by the model was around 80% or above for horizontal and downward flows (Figs. 4a, b and c). At this stage the SW flow pattern is still considered as a kind of ST&MI. The agreement reaches 95% for all cases if one considers the ST and ST&MI patterns as stratified flow patterns and all the rest as dispersed ones. Considering the horizontal flow (Fig. 4a), one may notice that the model overestimates the ST region.

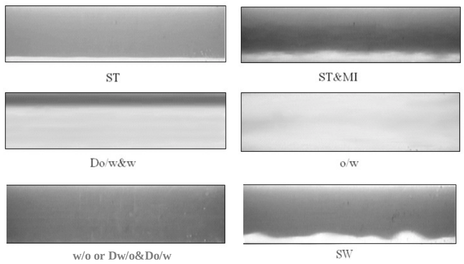


Figure 2. Pictures of the flow patterns observed in this work.

On the other hand, the ST&MI boundary works quite well (Fig. 4a). Such overall agreement is of the same order of those presented by the latest mechanistic models found the literature (Petalas and Aziz, 2000). With respect to the inclination angle effect on flow patterns, in downward and upward flow the ST pattern tended to disappear. The ST region was somewhat substituted by the SW pattern. Another remark regards the Do/w&w region, which tended to increase with downward inclination towards the ST&MI region (Fig. 4c). In the highest upward inclination a region of strong water backflow and recirculation was detected at low water and mid oil superficial velocities (Fig. 4d). The Trallero's model was also tested against data from literature and the agreement was of the same order of that observed in this work (Rodriguez *et al.*, 2004).

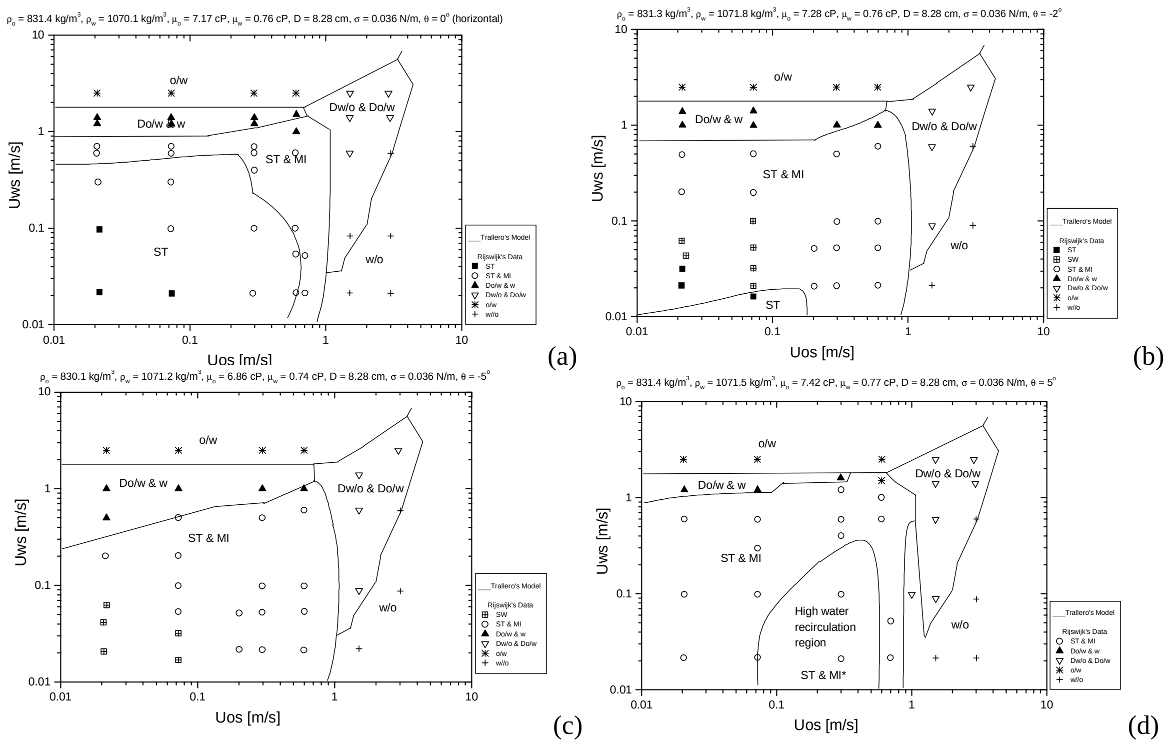


Figure 4. Experimental (dots) and predicted (lines) flow pattern maps, (a) Horizontal flow, (b) -2°, (c) -5° and (d) +5°.

5. Holdup and pressure gradient results

Figure 5 shows holdup ratio comparisons in between horizontal and slightly inclined flow data, the two-fluid model and the homogeneous model as a function of the water superficial velocities. The comparison is made via the (water cut)/(water holdup) ratio, C_w/ε_w , which gives a suitable relative representation of the liquid-liquid slip or *in-situ* phase accumulation. By inspection of Fig. 5 one may see that the two-fluid model (solid line) agrees reasonably well with the tendency presented by the experimentally obtained ST and ST&MI dots (refer also to Table 1). On the other hand, the dots related to o/w, w/o and Dw/o&Do/w flow patterns were better represented by the homogeneous model (dotted line, Fig. 5b). The results are only ambiguous for the dual-continuous Do/w&w flow pattern. In upward flow there is an expected trend of *in situ* accumulation of the denser phase, in this case water.

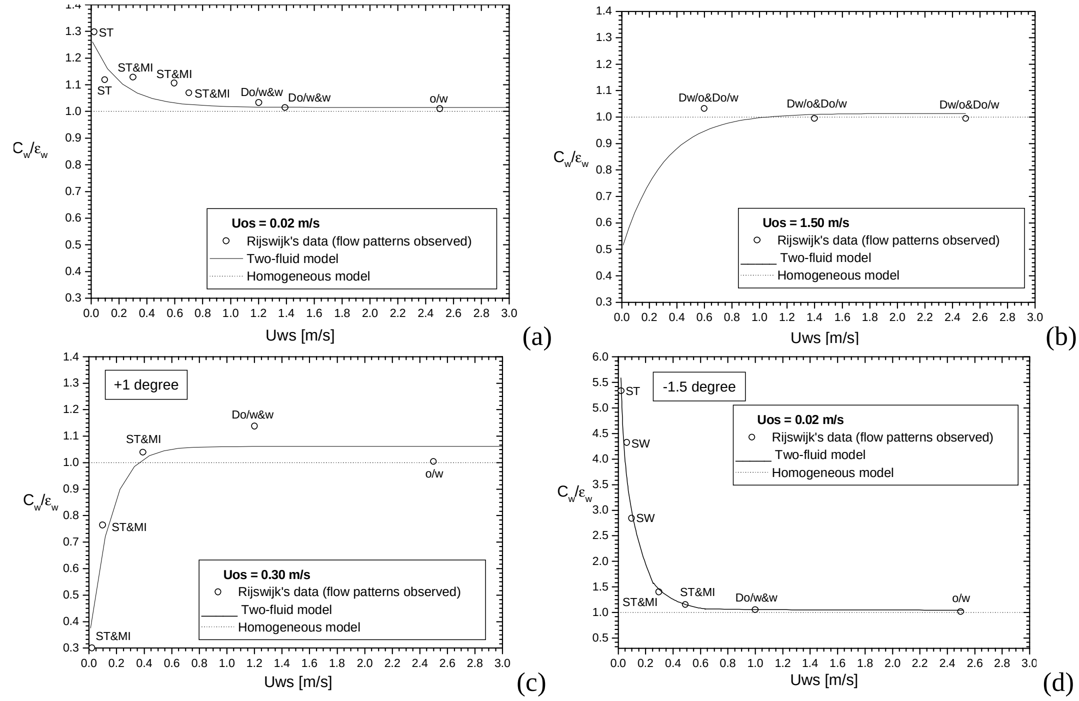


Figure 5. C_w/ε_w *vs* U_{ws} [m/s]; experimental results (dots), two-fluid model (solid line) and homogeneous model (dotted line); (a) 0^o, Uos = 0.02 m/s and (b) 1.50 m/s; (c) $+1^o$, U_{os} = 0.30 m/s, and (d) -1.5^o, U_{os} = 0.02.

Hence, the C_w/ε_w ratio is expected to reach lower values in comparison to horizontal flow (Fig. 5c). On the other hand, in downward flow the C_w/ε_w ratio is expected to reach higher values in comparison to horizontal and upward flow (Fig. 5d). After comparing qualitatively the data with the predictions of the holdup models it becomes rather clear that the two-fluid model should be applied to the ST and ST&MI flow patterns, whereas the homogeneous model should be applied to the o/w, w/o and Dw/o&Do/w flow patterns. The homogeneous model was arbitrarily chosen as the adequate holdup model for the Do/w&w flow pattern. The results of the holdup models (two-fluid model and homogeneous model applied to their respective flow patterns) are quantitatively compared with the data through the average relative error (e):

$$e = 100\frac{\sum_N \sqrt{\left(\frac{f_{FP}\left[(k_{\mathrm{mod}})_{2f},(k_{\mathrm{mod}})_{\mathrm{hom}}\right]-k_{\mathrm{exp}}}{k_{\mathrm{exp}}}\right)^2}}{N}[\%] \tag{3}$$

where f_{FP} denotes a functional relation with flow pattern, k is either holdup or pressure gradient, the subscript $_{mod}$ indicates model prediction ($_{2f}$ two-fluid model and $_{hom}$ homogeneous model) and the subscript $_{exp}$ the respective experimental point; N is the number of runs carried out.

The models were able to predict the water holdup in horizontal and upward flows (1, 2 and 5^o) with and accuracy of 15% (overall relative error of 10%). In downward flow (-1.5, -2, -5^o) the accuracy was of 25% (overall relative error of 10%). Such accuracies are of the same order of those computed when comparing the models to data from literature (Table 1, refer to Rodriguez *et al.*, 2004).

6. Pressure gradient

Figure 6a shows pressure gradient comparisons for horizontal-flow between data and models as a function of the water superficial velocities for several constant oil superficial velocities. The two-fluid model (solid lines) tends to underestimate the experimental points related to the stratified region (refer also to Fig. 4a), especially at the lowest water superficial velocities. However, the general trend is reasonably well predicted. The homogeneous model is doing a better job when comparing with experimental points related to the dispersed region (Fig. 6a, dotted lines; refer also to Fig. 4a). A higher disagreement in between the homogeneous model and the respective experimental points was observed only at the highest water and oil superficial velocities, where the model tends to overestimate the experimental points. Accuracies around 35% were observed in the horizontal flow and an average relative error of 19% (Fig. 6b). For the upward flows studied (+1, +2 and $+5^o$) the same accuracies around 35% were observed and an average relative error slightly lower (e = 15%). On the other hand, in the downward flows studied (-1.5, -2, -5^o) a significantly worse accuracy was observed due to the points around dp/dz = 0. An average relative error of 50% was computed. However, provided that the high-experimental-uncertainty points are excluded from the analysis, the same accuracy of 35% is obtained.

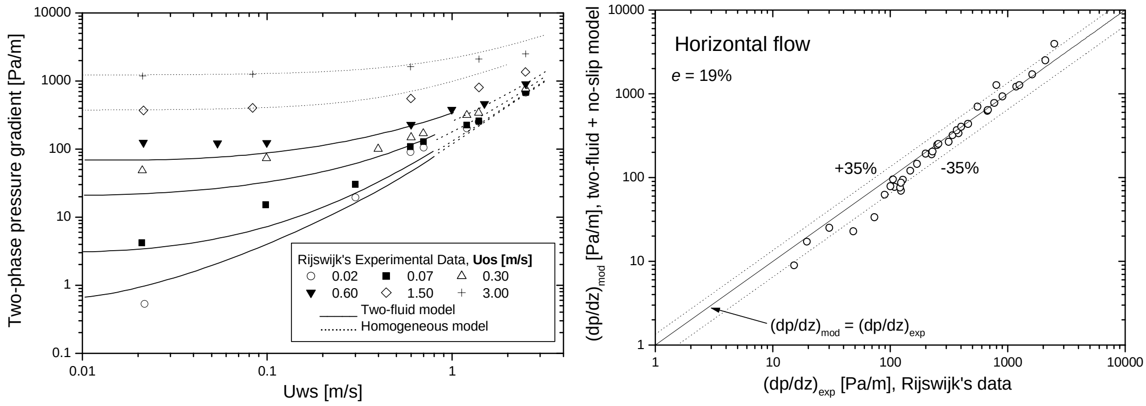


Figure 6. (a) Horizontal-flow oil-water pressure-gradient experimental data (dots), two-fluid model (solid lines) and homogeneous model (dotted lines); (b) model predictions against pressure gradients experimentally obtained.

After the evaluations carried out above, we consider that the flow pattern prediction model together with the two-fluid and homogeneous models are able to predict with reasonable accuracy the oil-water pressure gradients and holdups encountered in the horizontal and slightly inclined flows studied.

7. Inverse mode technique for oil and water production rates

Let's consider that the models proposed are suitable for flow pattern, holdup and pressure gradient predictions. One can then imagine that for some situations there would be for a given pressure gradient point a relatively small range of solutions of superficial velocities. However, it is not possible to be sure whether this point would be related to a dispersed or stratified flow pattern, for instance. One expects that to calculate the superficial velocities one requires at least two independent parameters (Rodriguez *et al.*, 2004). Holdup information could be used in order to evaluate which model would be more suitable for the inverse mode calculation. However, multiple solutions may exist even when crossing pressure drop and holdup information. Nevertheless, considering the practical application the range of solutions might be sufficiently small so that a reliable estimation of the flow rates could be ensured. Thus, both sets of data are applied together in order to reduce the range of possible superficial velocities or multiple solutions.

A better way of explaining the technique is through a graphical analogy. By applying the models herein proposed it is possible to generate solution surfaces for water holdup and pressure gradient as a function of the flow patterns and superficial velocities (Rodriguez *et al.*, 2004). From given pressure gradient and holdup points, planes parallel to the water and oil superficial velocities U_{os}-U_{ws} plane are taken intersecting the pressure-gradient and water holdup surfaces. These planes are then projected together onto the U_{os}-U_{ws} plane and the crossing of the multiple solutions can be seen in Fig. 7 for two typical cases. The point where both sets of multiple solutions taken from the pressure gradient and holdup surfaces intercept is the actual solution. Then, it is only a matter of reading the corresponding oil and water superficial velocities. This methodology is called Inverse Mode Prediction Unposed Technique (IMPUT) for multiphase flow. The accuracy between IMPUT results and the experimental data was estimated through the maximum deviation. When the models overestimate or underestimate the experimental data, the maximum deviation becomes positive or negative, respectively.

7.1. Low oil-water viscosity ratio ($\mu_o/\mu_w \cong 1.5$)

Figures 7 shows a direct comparison between the water and oil superficial velocities obtained by IMPUT and Elseth's (2001) experimental data. Although the overall agreement is satisfactory, for the higher water superficial velocity a systematic overestimation of the data can be detected (Fig. 7a), whereas for the higher oil superficial velocity the opposite trend is observed (7b). For higher water and oil flow rates the homogeneous model is applied and perhaps some slippage might actually still be taking place. Systematic errors in obtaining the data or/and data treatment can be also an explanation for that.

7.2. High oil-water viscosity ratio ($\mu_o/\mu_w \cong 30$)

We have also applied IMPUT to the typical case studied by Trallero (11). An attractive way of presenting the results of IMPUT is through the well-logging flow-pattern map. Figure 8 shows the flow map, where the open symbols are Trallero's experimental data and the crossed symbols are the results of IMPUT. A straight line links the correspondent points. Constant water cut (dashed) and pressure gradient (dotted) curves are also drawn onto the map. What is immediately observed from the map (Fig. 8) is that IMPUT errs mostly in the pressure gradient; the water holdup (cut really) appears to be a smaller source of uncertainty (naturally, either the data or the models may have systematic errors). It is also possible to see some flow pattern dependencies. It seems that the predicted points have a trend moving from the ST towards the ST&MI region. An opposite trend may be seen for the Dw/o&Do/w points, which seem to go systematically towards the ST&MI or Do/w&w region.

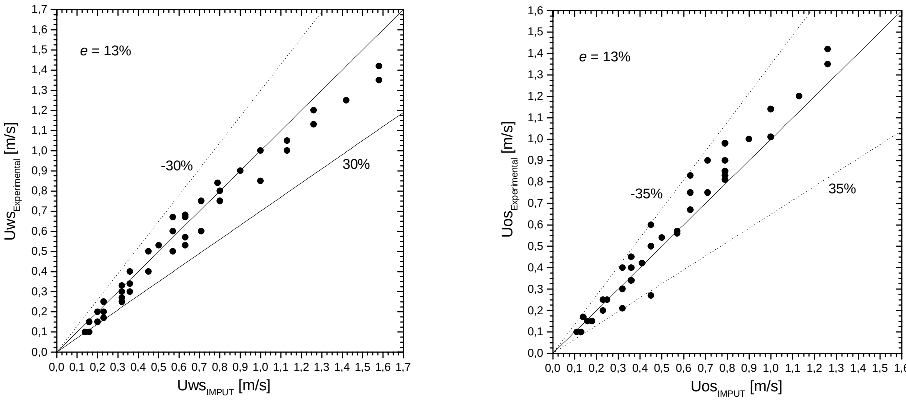


Figure 7. IMPUT *vs* Elseth's experimental data; (a) water superficial velocity (U_{ws}); (b) oil superficial velocity (U_{os}).

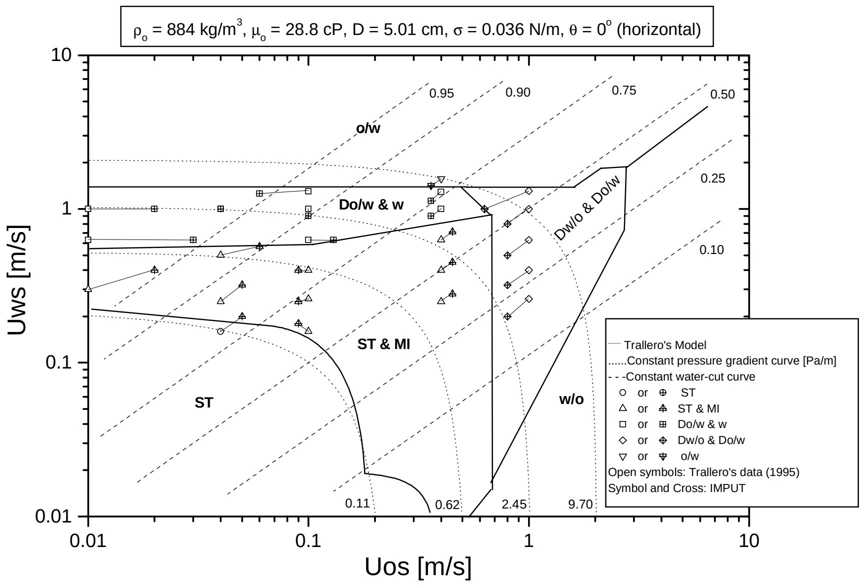


Figure 8. IMPUT *vs* Trallero's experimental data; well-logging flow-pattern map of the superficial velocities.

8. Conclusions

Flow patterns, phase holdups and pressure gradients have been measured for horizontal and oil/water flow in an 8.28 cm diameter steel pipe using mineral oil and brine as fluids at mixture velocities from 0.04 m/s to 5.55 m/s. The measuring accuracies of water holdups varied from 0.1 to 10% (at water holdups lower than 0.1) of range and were of the order of 1% of range for most of the experiments. The measuring accuracies for oil/water pressure gradients were of the order of 1% of range for most of the experiments. Finally, we have used the inversion of a multiphase flow pattern dependent model to calculate the velocities of the phases from known holdup and pressure loss in horizontal pipes. The following main conclusions can be drawn from this experimental study:

- Identification of the seven different oil/water flow patterns has been done on the basis of video recordings and holdup measurements with a gamma densitometer. Detailed horizontal and slightly inclined flow maps were generated over the entire range of flow rates.
- The observed flow patterns for horizontal, upward and downward inclined flow are reasonably well described by the Trallero's flow pattern map. For downward inclined flow a stable wavy structure was observed. For upward inclined flow regions with high water recirculation were detected. The stratified smooth flow pattern disappears with inclination and it is replaced by a stratified wavy flow pattern.
- The measured holdup and pressure gradient data have been compared with calculations using two simple models: the two-fluid model and the homogeneous model. Although these are valid for the extreme flow situations of complete phase separation (i.e. without entrainment) and complete mixing, respectively, the comparison provides valuable guidelines on the applicability and prediction accuracies when these models are used for intermediate flow configurations.

- With these simple models prediction accuracies varied with flow pattern and pipe inclination. For horizontal flow prediction accuracies for water holdups are of 15%. Pressure gradients are predicted with accuracies of 35%. For upward flow the prediction accuracies for water holdups and pressure gradients are also of 15% and 35%, respectively. For downward flow the prediction accuracies for water holdups and pressure gradients are of 25% and 35%, respectively.
- It is possible to correlate holdup and pressure gradient measurements with relatively small ranges of oil and water superficial velocities; therefore, although IMPUT (Inverse Mode Prediction Unposed Technique) is not straightforward (not well-posed), considering the practical application the range of solutions can be sufficiently small so that a reliable estimation of the flow rates can be ensured. For the low viscosity ratio case, the water superficial velocities were predicted with maximum deviation of 30%, with some overprediction at high rates, and the oil superficial velocities with maximum deviation of 35%, with some underprediction at high rates. For the high viscosity ratio case, the water superficial velocities were predicted with maximum deviation of 30%, with some underprediction at high rates, and the oil superficial velocities with maximum deviation of 65%

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