Capacitive wire-mesh sensor measurements in oil-water flow

Iara H. Rodriguez, Hugo F. Velasco P., Oscar M. H. Rodriguez
Mechanical Engineering Department
Engineering School of Sao Carlos – University of Sao Paulo
Sao Carlos, SP, Brazil
iarahrodri@gmail.com.br

Adriana Bonilla Riaño
Petroleum Engineering Department
Unicamp
Campinas, SP, Brazil

***Abstract*—In this paper, a capacitive wire-mesh sensor was applied to investigate viscous-oil in water dispersed flow in a transparent acrylic section of 26-mm-i.d. and 12-m-length. The sensor was used to obtain in-situ volumetric phase fractions (holdup) and phase distributions in the pipe cross-section. Two mixture permittivity models from the literature, Maxwell–Garnett and Power–Law were applied to calculate the oil volumetric phase fractions in order to compare with the phase fraction measured via quick-closing valves technique (QCVs). In these models the relation is modified as function of a variable parameter. This paper presented a new attempt to find a suitable relation for holdup measurements in oil-water dispersed flows.**

Keywords—capacitive sensor; wire-mesh; oil-water flow; phase distribution; holdup, dispersed flow.

I. Introduction

The water proportion in crude oil production is increasing day by day in the current offshore scenario, which explains in part the attention that the flow of oil-water mixtures is receiving from the researchers. In particular, dispersed flow pattern, where one phase is dispersed as droplets into the other continuous phase, is common in crude oil transmission and offshore pipelines, with either oil or water as the dominant phase. These flows have many applications in a diverse range of process industries but particularly in the petrochemical industry, where oil and water are often produced and transported together. Several techniques have been developed for measuring multiphase flows and obtaining parameters that are of great importance to the study of oil-water flows as in-situ phase volumetric fraction, phase distribution, velocities of the phases. However, the existing literature covers mainly the application of measurement techniques in gas-liquid flows. In liquid-liquid flows [1] and [2] used a high-frequency needle probe to obtain images of the phase distribution of oil and water over the pipe cross-section, but only time-averaged data were obtained. Dual-sensor conductivity probes have been applied to generate local oil volume fractions distributions as well as velocity distributions in oil-in-water flows [3]. The developed probe was capable to generate images of the flow, but with only limited spatial resolution. Electrical techniques as electrical resistivity tomography (ERT) have been also applied to investigate oil-water flow [3, 4]. Reference [5] has employed electrical capacitance tomography (ECT) to investigate stratifying kerosene-water flow. However, these techniques are known to produce low spatial resolution images. Gamma ray densitometry is a non-intrusive method that has shown good spatial resolution but not enough temporal resolution for measuring local phase fractions in oil-water flow systems [6-9].

The wire-mesh sensor is an intrusive imaging device based on conductivity or capacitance measurements which provides high spatial and temporal resolutions. However it has been applied mainly for investigation of gas-liquid flows [10-12]. A capacitive wire-mesh sensor has been applied to investigate dispersed flow of oil and water in a horizontal glass pipe [13, 14]. In-situ volumetric phase fractions were measured using four mixture permittivity models from the literature to calculate the phase fraction. Two permittivity models were found to describe better the behavior of the studied dispersed oil-water flow. The Maxwell–Garnett model for the fully dispersed flow of oil and water and the Logarithmic model for the dual continuous flow. Reference [15] has also applied a capacitive wire-mesh sensor to obtain holdup in viscous oil-water flow in acrylic pipe. The authors tested twelve different models for calculating the oil fraction from the sensor data. Series and Maxwell- Garnett w/o showed the lowest values of average relative error, 29.48% and 19.58%, respectively. Two trends were observed, the Series model suited better for low oil fractions (0.14–0.29) and Maxwell–Garnett to higher oil fractions (0.36–0.48). However the errors are considerably large. Although the authors had applied a considerable number of models in oil-water flow in order to find out a single permittivity model for dispersed flows, there is not still a widespread model that offers a better agreement between theoretical and experimental results for capacitive WMS. In this case, the present paper has been done as a new attempt to find a suitable relation for holdup measurements in oil-water dispersed flows, through the application of parametric models. The difference of these models, in comparison with those applied above [13-15], is that the relation is modified as function of a variable parameter. In this work the aim is to find a single model for the entire range of oil phase fraction studied.

II. EXPERIMENTAL

A. Experimental setup

Experiments were performed in the Multiphase Flow Test Facility at NETeF (Thermal-Fluids Engineering Laboratory) of the Engineering School of Sao Carlos – University of Sao Paulo in Brazil. The multiphase-flow loop is shown schematically in Fig. 1. Experiments were carried out in a transparent acrylic pipe of 26-mm-i.d. and 12-m length and water and oil (828 kg/m^3 of density and 220 mPa s) were used as test fluids. The acrylic pipe is supported by a metallic structure (blue structure in the middle of the scheme shown in Fig. 1). Oil and water are stored separately in tanks made of plastic and are pumped out by two Positive displacement pumps. Oil and water phases join together before the entrance of the horizontal test section through a Y-junction (Multiphase mixer). Oil and water flow rates are measured with positive displacement and vortex flow meters. After the test section the mixture of oil and water is transported to a coalescent-plate liquids separator tank. After the separator, the oil and water phases are returned to their respective storage tanks. Two quick-closing valves (solenoid valves) were installed at each end of the test section allowing the measurement of in-situ volume fraction. A wire-mesh sensor based on capacitance measurements was used to obtain in-situ phase fraction and phase distributions in the pipe cross-section. Measurements were made for mixture superficial velocities varying from 1.5 to 4.6 m/s and input oil fractions from 3% to 48%. In total, 64 tests were carried out with the capacitive sensor. In- situ oil fractions were measured for twenty experimental points using QCVs. These measurements were compared to those obtained with the wire-mesh.

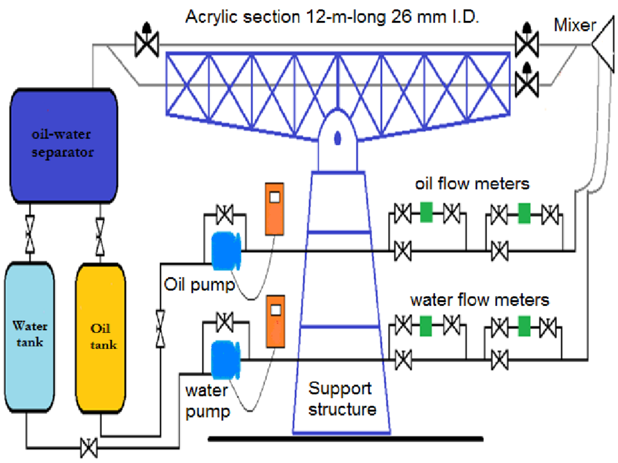

Fig. 1. Schematic view of the Multiphase flow loop at NETeF.

B. Wire-mesh sensor

The capacitive sensor consists of two planes of wire electrodes (transmitter and receiver wires). The prototype employed in the experiments consists in an 8 × 8 wires grid (Fig. 2). The sensor was installed at the end of the test section (10.3 m from the tube entrance) in between the two halves of a Perspex visualization section (Fig. 2). The associated electronics measures the local electrical permittivity at all crossing points by successively applying a sinusoidal alternating voltage to each one of the sender electrodes at one wire plane and measuring in parallel the current flowing towards the receiver electrodes at the other wire plane. In this way, the wire-mesh sensor subdivides the cross section into a number of sub-regions and determines the phase present in each one of those sub-regions independently in a fast and multiplexed way. For more details on the wire-mesh data processing and electronics principle see [11].

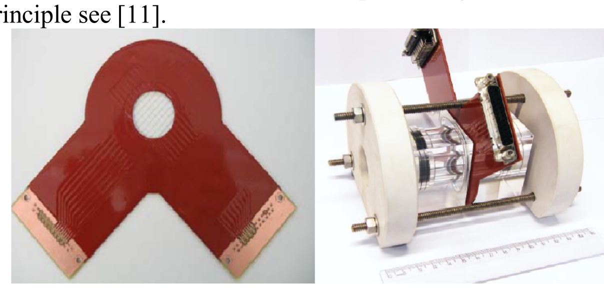

Fig. 2. Prototype 8x8 and sensor installed in between the two halves of the Perspex visualization section.

C. Measuring electronics

The capacitive wire-mesh circuit delivers a voltage related with the relative permittivity according to

$$V = a.\ln(\varepsilon_x) + b \;, \tag{1}$$

where V is the voltage, ε_x is the relative permittivity of the mixture, and a and b are constants that depend on geometric factors and characteristics of the excitation signal. Thus, there is a variation in the measured values at each cross point for the same fluid. Therefore, it is necessary an adjustment or calibration process to compensate this variation. The adjustment procedure consists of measuring a substance of low permittivity and a known permittivity value ε_L (oil for example, ε_o = 3.5) covering the entire sensor. Thus, it is obtained a reference voltage data array denoted as V_L:

$$V_L(i,j) = \frac{1}{N_t}\sum\nolimits_{k=0}^{N_t} V(\varepsilon_L, i, j, k)\,, \tag{2}$$

which is an raw data average over a range time, $k = 0, ..., N_t$. Here, i and j are the index of the cross point and k is the time index. The procedure is repeated whit the sensor covered with another substance with higher permittivity, ε_H , providing another reference voltage array denoted as V_H. Thus, applying (1) to the reference arrays V_L and V_H the constants a and b are calculated for each cross point as

$$a(i,j) = \frac{V_H(i,j) - V_L(i,j)}{\ln(\varepsilon_H) - \ln(\varepsilon_L)}\,, \tag{3}$$

$$b(i,j) = \frac{V_L(i,j)\ln(\varepsilon_H) - V_H(i,j)\ln(\varepsilon_L)}{\ln(\varepsilon_H) - \ln(\varepsilon_L)}\,. \tag{4}$$

Thus, the values of permittivity for each crossing point, ε_x, over the entire cross section can be determined by

$$\varepsilon_x(i,j,k) = \exp\left(\frac{V(i,j,k) - b(i,j)}{a(i,j)}\right). \qquad (5)$$

After that, a permittivity model that relates relative permittivity, $\varepsilon_x(i,j,k)$, and the local phase fraction, $\alpha_x(i,j,k)$ is used. These models are explained in the next section.

Finally, a total space and time averaged volumetric phase fraction is obtained averaging the local phase fraction over the cross section

$$\alpha_x = \frac{1}{T_t} \sum_{i=1}^{i\max} \sum_{j=1}^{j\max} \sum_{k=1}^{k\max} w(i,j).\, \alpha_x(i,j,k), \qquad (6)$$

where $i_{\max}$ and $j_{\max}$ are the total numbers of electrode wires in both directions, $k_{\max}$ is the number of instantaneous volumetric phase fraction in the measuring sequence and $w(i,j)$ are weight coefficients reflecting the contribution of the area of the given cross point (i,j) to the total cross sectional area A_{sensor} (see Fig. 3 [16]).

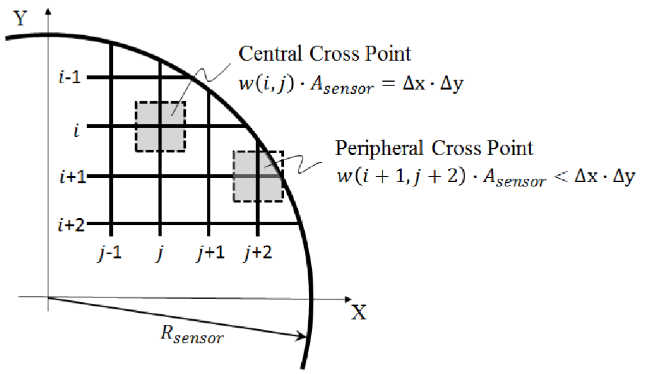

Fig. 3. Weight coefficients $w(i,j)$ for averaging the oil volumetric phase fraction in the measuring cross section (Fig. adapted from [16]).

High viscous Oil and water used as test fluids have a relative permittivity of 3.5 and 78.3, respectively, at 5MHz. These values were obtained with an Impedance Analyzer Solartron 1260 with a Dielectric Interface Solartron 1296. The implemented WMS system has a time constant (dynamic response) of 0.8 µs. Each experiment was acquired at 500 fps during 120 s.

III. PERMITTIVITY MODELS

The capacitive wire-mesh measurements provide the relative permittivity for each cross point. Then, it is necessary a relation between permittivity and the phase fraction. This relation is made through mixture permittivity models found in the literature. There are several permittivity models; each one has been designed for specific electrodes geometry (sensor) and different distribution of the phases (flow pattern). Studies on the estimation of mixture permittivity in dispersed flows are very common. Nevertheless, most of them are focused on the investigation of gas-liquid mixtures [17]. In [18, 19] is presented a summary of different models found in the literature. Recently, twelve models were tested to calculate the local oil fraction in dispersed oil-water flow: Bruggeman (three different), Series, Parallel, Birchak, Looyenga, Logarithmic, Maxwell (two different) and Hanai (two different) model [15]. Note that in (7) and (8); the calculated oil fraction refers to the local phase fraction. These models are properly described in [15]. Two models described better the oil phase fraction data obtained experimentally using QCVs, the Maxwell–Garnett and Series model. Two trends were observed. For low input oil fractions the Series model was better suited. On the other hand, for higher values of input oil fractions the Maxwell–Garnett model fitted better the oil-fraction data. In this paper two other relations found in the literature were tested for oil phase-fraction calculation: The Power–Law model [18] defined as:

$$\alpha_o = \frac{\varepsilon_x^{\beta} - \varepsilon_w^{\beta}}{\varepsilon_o^{\beta} - \varepsilon_w^{\beta}}, \qquad (7)$$

where the subscripts w and o denote oil and water phase respectively, α is the local phase fraction, ε is the relative permittivity and β is a dimensionless parameter that varies between 0 and 1.

The second model applied was Maxwell–Garnett [20].

$$\alpha_2 = \frac{((\varepsilon_x/\varepsilon_1) - 1)((\varepsilon_2/\varepsilon_1) + u)}{((\varepsilon_x/\varepsilon_1) + u)((\varepsilon_2/\varepsilon_1) - 1)}, \qquad (8)$$

where the subscripts 1 and 2 denote the continuous and dispersed phase, respectively. The dimensionless parameter u depends on the shape of the ellipsoid (dispersed phase) and varies from 0 to ∞. It is important to note that Maxwell-Garnett equation used previously in [15] is the best known form of Maxwell equation for the specific case in which u=2, for spheres. The other two special cases are $u \to 0$, for discs and $u \to \infty$, for needles [20].

Equation (7) was used to calculate the local oil fraction varying the parameter β from 0 to 1. The total averaged oil fraction [(6)] was compared to the oil fraction obtained using QCV's. The relative error in between these two values was calculated for each experimental point and finally the averaged relative error (ARE) was obtained for each parameter. The procedure is repeated with (8) varying the parameter u in between 0 and ∞. The average relative error, ARE, was estimated as follows:

$$ARE = 100 \frac{\sum_{1}^{N} \sqrt{\left(\frac{\alpha_o - \alpha_{o,QCV}}{\alpha_{o,QCV}} \right)^2}}{N} [\%], \qquad (9)$$

where subscript $\alpha_{o,QCV}$ stands for the oil fraction measured by the quick-closing valves technique and α_o for the averaged oil fraction obtained using mixture permittivity models. N is the number of experiments.

IV. Results and Discussion

A. Phase volumetric fraction

Fig. 4 shows the ARE of the averaged oil fraction calculated with Power–Law model as a function of the parameter β. The trend of the curve indicates that the ARE tends to increase when β varies from 0 to 1. Even when β → 0 the errors are considerably large.

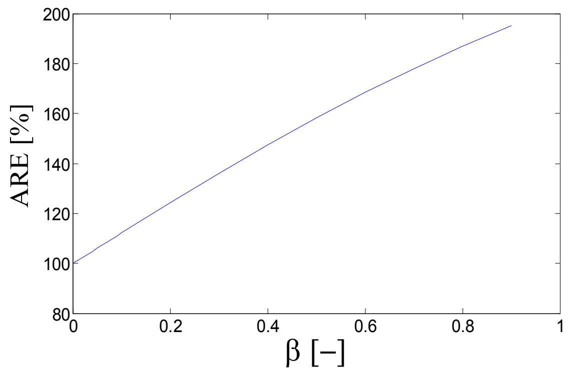

Fig. 4. Oil–phase-fraction average relative error as a function of the parameter β (Power-Law model).

In Fig. 5 it is presented the variation of the ARE of the averaged oil fraction calculated with Maxwell-Garnett model as a function of the parameter *u*. The lowest value of the ARE was obtained when $u \to 0$, i.e., 39.11%. Increasing the value of *u* the ARE increased sharply in the beginning and then slightly until reaching an almost constant value.

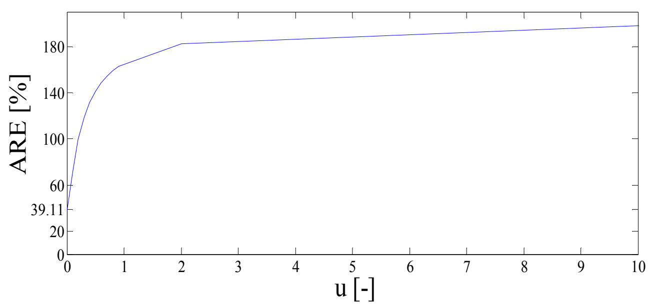

Fig. 5. Oil phase fraction average relative error as a function of the parameter *u* (Maxwell-Garnett model).

In [15] the lowest values of error were observed for Series and Maxwell–Garnett, 29.48% and 19.58%, respectively. However, the Series model suited better for low oil fractions (0.14–0.29) and Maxwell–Garnett to higher oil fractions (0.36–0.48). In Fig. 6 one can see the average relative error for the twelve models tested in [15] and the two used in the current paper, in total 14 models. In this case the ARE was calculated for all experimental points (oil fraction varying from 0.14 and 0.48) using each model. The ARE for Series model (Ser) and Maxwell–Garnett (Max1) applied in [15] was 27.22% and 55.01%, respectively (Fig. 5). In the current study the ARE of the Maxwell–Garnett model (Max(*u*)), when $u \to 0$, is 39.11%.

In conclusion the two models that described better the whole set of data showing a lower value of average relative error (ARE) are Series [15] and Maxwell-Garnett (Max(u)) with ARE of 27.22% and 39.11%, respectively. However, the values of the errors are still quite high. One possible explanation for the large errors may be that these models were not created specifically for the WM conditions. In this study two conditions are not satisfied: a homogeneous electromagnetic field and a high-permittivity fluid within one of low-permittivity (dispersion of water-in-oil, in which $\alpha_o >> 0$) [21-23]. Some other factors that could be affecting the measurements with the wire-mesh are the calibration process and variations in the oil temperature that seems to affect strongly the measurements. It still needs to be verified.

V. Conclusions

In this paper are shown the results of two parametric models for the oil phase fraction calculation. These results were compared with those obtained by twelve models used previously. The errors obtained in the oil fraction calculated using the Power–Law model was considerably large. On the other hand, the Maxwell–Garnett model showed a better result. The error obtained with the Maxwell-Garnett model is still large but in this case the model seems to suit well to all oil fraction range. Another model that showed lower errors in predicting the oil fraction is the Series model. An attempt to decrease the error is determining a new permittivity model, through computational simulations adjusted to the wire-mesh sensor geometry and flow pattern. This study is in order.

Although the current study provide new guidelines on the applicability of wire-mesh sensor as a measurement technique for two-phase flows involving oil and water, more experiments are necessary to assess the possible effects of some parameters as flow pattern, phase distribution, oil fraction on the permittivity model. A possible effect of the calibration routine and variations in oil temperature in the wire-mesh measurements are still being investigated. The flow-pattern detection using visual technique will assist the analysis on the distribution of the phases using the wire-mesh sensor. These measurements are in order.

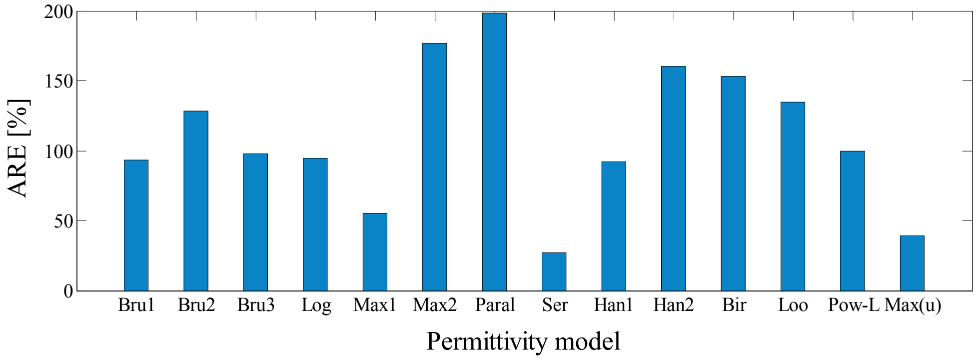

Fig. 6. Comparison between the average relative error in the calculated values of oil phase fraction using different permittivity models.

ACKNOWLEDGMENT

The authors are grateful to FAPESP (Fundação de Amparo à Pesquisa do Estado de Sao Paulo, proc. 2010/08688-3) and CAPES (Coordenação de Aperfeiçoamento de Pessoal de Nível Superior, proc. 00011/07-0) for the financial support given to this research.

REFERENCES

[1] P. Angeli, G. F. Hewitt, "Flow structure in horizontal oil–water flow," *Int. J. Multiph. Flow*, vol 26, pp. 1117–1140, 2000.

[2] J. Lovick, P. Angeli, "Experimental studies on the dual continuous flow pattern in oil–water flow," *Int. J. Multiph. Flow*, vol 30, pp. 139–157, 2004.

[3] X. Zhao, G.P. Lucas, "Use of a novel dual-sensor probe array and electrical resistance tomography for characterization of the mean and time-dependent properties of inclined bubbly oil-in-water pipe flows," *Meas. Sci. Technol*, vol 22, pp. 104012, 2011.

[4] H. Li, M. Wang, Y. Wu, Y. Ma, R. Williams, "Measurement of oil volume fraction and velocity distributions in vertical oil-in-water flows using ERT and a local probe," *J. Zhejian Univ. Sci*., vol 6, pp. 1412–5, 2005.

[5] N.M. Hasan, B.J. Azzopardi, "Imaging stratifying liquid–liquid flow by capacitance tomography," *Flow Meas. Instrum*., vol 18, pp. 241–246, 2007.

[6] G. Elseth, "An experimental study of oil–water flow in horizontal pipes," PhD Thesis, Telemark University College, Porsgrunn, 2001.

[7] O.M.H Rodriguez, R.V.A. Oliemans, "Experimental study on oil–water flow in horizontal and slightly inclined pipes," *Int. J. Multiphase Flow*, vol 32, pp. 323–343, 2006.

[8] W.A.S. Kumara, B.M. Halvorsen, M.C. Melaaen, "Pressure drop, flow pattern and local water volume fraction measurements of oil–water flow in pipes," *Meas. Sci. Technol.,* vol 20, pp. 114004, 2009.

[9] W.A.S. Kumara, B.M. Halvorsen, M.C. Melaaen, "Single-beam gamma densitometry measurements of oil–water flow in horizontal and slightly inclined pipes," *Int. J. Multiphase Flow*, vol 36, pp. 467–480 , 2010.

[10] H-M. Prasser, "Novel experimental measuring techniques required to provide data for CFD validation," *Nucl. Eng. Des*., vol 238, pp. 744–770, 2008.

[11] M.J. Da Silva, E. Schleicher, U. Hampel, "Capacitance wire-mesh sensor for fast measurement of phase fraction distributions," *Meas Sci Technol*., vol 8, pp. 2245–2251, 2007.

[12] L. Szalinski et al., "Comparative study of gas-oil and gas-water two-phase flow in a vertical pipe," *Chemical engineering science*, vol 65, pp. 3836–3848, 2010.

[13] M.J. Da Silva, E.N. dos Santos, U. Hampel, I.H, Rodriguez, O.M.H. Rodriguez, "Phase fraction distribution measurement of oil–water flow using a capacitance wire-mesh sensor," *Meas. Sci. Technol*., vol 22, pp. 104020, 2011.

[14] I.H. Rodriguez, H.K.B. Yamaguti, M.S. de Castro, M.J. Da Silva, O.M.H. Rodriguez, "Drag Reduction Phenomenon in Viscous Oil-Water Dispersed Pipe Flow: Experimental Investigation and Phenomenological Modeling," *AIChE Journal*, vol 58, pp. 2900-2910, 2011.

[15] H.F.V. Peña, A.B. Riaño, I.H. Rodriguez, O.M.H. Rodriguez," Evaluation of Permittivity models for holdup measurements of viscous-oil in water dispersed flow," In: Proceedings of the 4th International Conference on Multiphase Flow, Jeju, May 26-31, South Korea, 2013.

[16] H.-M Prasser., E. Krepper, D. Lucas, "Evolution of the two-phase flow in a vertical tube-decomposition of gas fraction profiles according to bubble size classes using wire-mesh sensors," *International Journal of Thermal Sciences*. 41 (2002) 17–28."

[17] A. Jaworek, A. Krupa, "Phase-shift detection for capacitance sensor measuring void fraction in two-phase flow," *Sensors and Actuators A-Physical*, vol. 160, pp. 78–86, 2010.

[18] K. K. Karkkainen, A.H Sihvola, K.I Nikoskinen,"Effective permittivity of mixtures: numerical validation by the FDTD method," *IEEE Transactions on Geoscience and Remote Sensing*, vol. 38, pp. 1303–1308, 2000.

[19] T. Hao, Ed. "Dielectric properties of non-aqueous heterogeneous systems," *Studies in Interface Science*, Elsevier, vol 22, pp. 341-423, 2005.

[20] A. Sihvola, "Electromagnetic Mixing Formulas and Applications," The Institution of Engineering and Technology, Michael Faraday House, Six Hills Way, Stevenage SG1 2AY, UK: IET, 1999.

[21] T. R. McKeen, T. S Pugsley,"The influence of permittivity models on phantom images obtained from electrical capacitance tomography," *Measurement Science and Technology*, vol. 13, pp. 1822–1830, 2002.

[22] E.F May, B.F Graham, A.S.Chauhan, R.D. Trengove,"Shear and Electrical Property Measurements of Water-in-Oil Emulsions and Implications for Multiphase Flow Meters," *Energy & Fuels*, vol. 22, pp. 3308–3316, 2008.

[23] H. Looyenga, "Dielectric constants of heterogeneous mixtures," *Physica*, vol. 31, pp. 401–406, 1965.