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Liquid characterization and measurement of fluid properties for reduced uncertainty in multiphase flow area fraction measurements

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ABSTRACT

Meters measuring multiphase flows use one or more physical properties of the fluids to estimate flow area fractions of phases and components. Most common in the oil and gas industry are meters based on measurement of gamma ray attenuation and permittivity. Uncertainty about the actual values of attenuation coefficients and permittivity will lead to systematic errors which we analyze and exemplify. To counter these errors it is desirable to monitor the properties of the fluids on-line with the flow measurement. Subsequently we present measurements of liquid phase properties since these are found to impact flow area fraction measurements more significantly. Dual-modality densitometry, which is based on measurements of gamma attenuation coefficients, is used to characterize liquid components in terms of density and composition. This technique is demonstrated to be well suited for the task, albeit the compositional results are less accurate, and do not allow for precise interferences regarding the permittivity.

1. Introduction

Commercial multi-phase flow meters (MPFM) applied in hydro-carbon production often employ measurements of gamma attenuation, conductivity or permittivity (electrical impedance), and combinations thereof. Typically gamma attenuation is used to distinguish between gas and liquid, and permittivity can be used to distinguish between oil and water [15]. Alternatively, two gamma energies, an order of magnitude apart, can create a contrast between hydrocarbons and water [11]. Judging from an earlier review by Ismail et al. [17], meters employing both gamma-ray methods and electrical ones seem to have become more common lately [30] at the expense of meters using electrical impedance only [22].

MPFMs loose accuracy if the employed properties deviate from values used during calibration, or values obtained by infrequent off-line sampling. For example, an increase in the gamma attenuation of the water component will cause the gas fraction to be under-read and an over-reading of oil. Property changes may be caused by changes in salinity, chemical additives, and process conditions.

In order to maintain accuracy and reduce overall uncertainty of flow meters it is thus desirable to measure the properties on-line with the flow measurement itself. To this end Christian Michelsen Research AS and the University of Bergen developed the Subsea Online Fluid Analyzer [2] in which a small sample of the multiphase flow is taken into a chamber and subsequently left to separate. This allows characterizations to be performed on individual phases and components.

In the following we analyze the basic influence of properties uncertainties, and give some examples on how fluid properties influence on the uncertainties in area fraction measurements. These are not elucidated in the presently available literature [7,10], but should be compared to the overall uncertainties discussed there. But it is appreciable that as the overall performance of meters advance, uncertainties arising from changing fluid properties will become more important.

Currently fluid characterization is often limited to an estimate of water salinity. The salinity of the water will affect both gamma attenuation and permittivity, and might be estimated by; additional gamma energies [26], conductivity/permittivity measurement [32,23], and measurements of scattered gamma-rays [18,29].

Corollary to an analysis of errors related to fluid properties, we present a liquid property measurement technique – so called dual modality densitometry [16] which measures the attenuation coefficient directly, and also allows for density and compositional information to be extracted.

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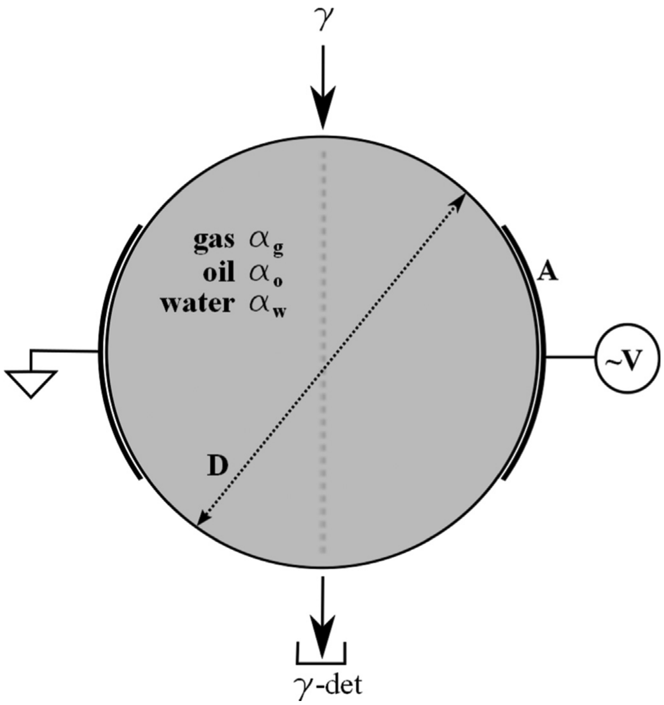

Fig. 1. Basic flow area fraction measurements of a homogenous flow in a pipe of diameter D. The fractions of gas, oil and water, α_i, are measured using gamma-rays (γ) sent from the top through the mixture toward a detector at the bottom, and by a capacitance measurement (~V) with electrodes of area A.

2. Uncertainties in flow area fraction measurements due to fluid properties

2.1. Basic flow area fraction measurements

In order to estimate the impact of changes in properties we consider a minimal and simplified configuration for flow area fraction measurement as depicted in Fig. 1. The flow is homogenous and its cross-section measured using gamma-ray attenuation and capacitance measurements.

The response of the gamma-measurement, using Lambert–Beer's Law for the attenuation of gamma-rays, will be,

$$M_\gamma = -\frac{1}{D}\ln\left(\frac{I}{I_0}\right) = \mu_g\alpha_g + \mu_o\alpha_o + \mu_w\alpha_w \tag{1}$$

where I is the measured intensity and I_0 a calibration with an empty cross-section. Area fractions, α_i, and (gamma) attenuation coefficients, μ_i, are subscripted with phase/component as defined in Fig. 1. D is the distance over which the attenuation takes place.

The (relative, static) permittivity of the homogenous mixture is measured using a (near) parallel plate capacitor, and the response of the capacitance measurement is,

$$M_\varepsilon = \frac{D}{A}\frac{C}{\varepsilon_0} = \varepsilon_g\alpha_g + (1-\alpha_g)\cdot\varepsilon_l(\varepsilon_o, \varepsilon_w, \beta) \quad , \beta = \frac{\alpha_w}{\alpha_w + \alpha_o} \tag{2}$$

where C is the measured capacitance, A the electrode area, ε_0 is the permittivity of free space and ε_g the permittivity of the gas phase. β is the water liquid ratio (WLR) in the liquid phase. The permittivity of the liquid phase, $\varepsilon_l(\varepsilon_o,\varepsilon_w,\beta)$, is given by Boyle [4] as an implicit equation for the permittivity of water–oil mixtures.

From the two equations above it is clear that we address ideal implementations, and neglect errors and intricacies associated with e.g. build-up and fringe fields. The short-comings associated with the plate capacitor approach to permittivity may be mitigated by implementing the permittivity modality using micro-wave techniques rather than the depicted circuit techniques [13,32].

Essentially the two modalities, save scaling and calibration as indicated, simply measure the (gamma-) attenuation and permittivity of the mixture and in combination with continuity,

$$\alpha_g + \alpha_o + \alpha_w = 1 \tag{3}$$

allow to solve for the area fractions, α_i, if properties, μ_i and ε_i, are known.

The permittivity modality may be replaced with a second gamma modality operating at a different energy. Such dual energy gauges [19] may then be analyzed by substituting Eq. (2), for an equation with the gamma-ray attenuation coefficients at the secondary photon energy. This yields a linear system of equations as analysed by Scheers [26].

MPFMs and area fraction measurements may consist of many combinations of electrodes and beams in a tomographic arrangement [15,22]. These additional views reduce the uncertainty caused by spatial distributions of the phases thus lessening the requirement of homogeniticity, but they do not remove the basic dependence of the measurement on the properties.

2.2. The properties

The basic measurement system, Eqs. (1)-(3), for area flow fractions is determined by the properties, attenuation and permittivity, and it is clear that errors in these will lead to systematic errors in the calculated area fractions. Changes in properties are not likely to be random, but rather to manifest themselves as drifts and shifts during production. The parameters may also change from calibration of the MPFM to the installation.

The properties may again be expressed in terms of sub-properties. The gamma-attenuation is given by,

$$\mu = {}^{M}\mu(\boldsymbol{x}, E)\cdot\rho(\boldsymbol{x}, p, T) \tag{4}$$

where ${}^{M}\mu$ is the mass attenuation which depends the composition, $\boldsymbol{x}$, and on photon energy, E. And the density, ρ, on composition, pressure, p, and temperature, T.

For the permittivity-a far more complex quantity than we may address here-we only modestly state;

$$\varepsilon = \varepsilon(\boldsymbol{x}, \rho, T) \tag{5}$$

For all properties $\boldsymbol{x}$ is some compositional vector that suits the context – e.g. weight fractions of elements for the mass attenuation coefficients, concentration of ionic species in case of water density [20], and concentrations of polar and polarizable hydrocarbons and classes of hydrocarbons for the permittivity and densities of oil [12,9]. The density would correlate attenuation and permittivity. In addition thermodynamic equilibrium relations would exist in and among components and phases.

We will subsequently propagate errors through the system as uncorrelated. A more complete analysis suited to a particular meter in a particular application should attempt to define relevant correlations and identify independent variables. The technique we use to propagate errors in the subsequent section may readily be applied in such circumstances as well. Further we will attempt to measure the attenuation coefficients directly and independently.

2.3. Propagation of errors

The uncertainty/error[1] in the flow area fractions is analysed by

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[1] We use the terms interchangeably. In strict sense they are errors when referring to simulations in which we know the true value, but uncertainty when using the results to say something about a real setting where the true value is unknown.