MEASUREMENT OF COMPONENT RATIOS IN OIL - WATER - GAS SYSTEMS USING DUAL ENERGY GAMMA-RAY ABSORPTION

H. van Santen

Delft, December 1993

Framework: Graduation at Delft, University of Technology Delft, The Netherlands.
Location: Koninklijke/Shell Exploratie en Productie Laboratorium, Rijswijk, The Netherlands.
Professor: Prof. dr. ir. H. E. A. van den Akker, Kramers Laboratorium voor Fysische Technologie.
Mentors: Ir. A. M. Scheers, Koninklijke/Shell Exploratie en Productie Laboratorium; Dr. R. F. Mudde, Kramers Laboratorium voor Fysische Technologie.
SUMMARY

Dual energy γ-ray absorption techniques can be employed for measuring the composition of oil-water-gas mixtures in closed systems such as pipes.

This report presents the principle of operation, limitations, accuracy considerations and optimisation considerations. In particular, the magnitude of the main sources of error in a dynamic oil-water-gas system are given for most situations.

Two types of experiments were conducted. Firstly, static experiments with a new energy combination, 22 keV of $^{109}$Cd and 41 keV of $^{153}$Gd, and dedicated filtering techniques. $^{109}$Cd–$^{153}$Gd is an interesting source because it allows to monitor compositions with a Si detector with a poor energy resolution, without applying complicated background corrections. Secondly, dynamic experiments, combining the dual energy γ-ray absorption composition measurement with a venturi velocity measurement. This is a promising method for on-line determination of the mass flow rates of each component of oil-water-gas mixtures with a water cut ranging from 0 to 100% and with a low (<40%) gas volume fraction.
## CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summary</td>
<td>3</td>
</tr>
<tr>
<td>Contents</td>
<td>5</td>
</tr>
<tr>
<td>1 Introduction</td>
<td>9</td>
</tr>
<tr>
<td>2 Principle of the measuring method</td>
<td>13</td>
</tr>
<tr>
<td>2.1 Three-phase composition measurement using two γ-energies</td>
<td>13</td>
</tr>
<tr>
<td>2.1.1 General absorption formula</td>
<td>13</td>
</tr>
<tr>
<td>2.1.2 Count rate through a pipe with OWG mixtures</td>
<td>15</td>
</tr>
<tr>
<td>2.1.3 Working equation</td>
<td>17</td>
</tr>
<tr>
<td>2.2 Measuring velocity with a venturi in homogeneous incompressible flow</td>
<td>19</td>
</tr>
<tr>
<td>2.3 Conclusions</td>
<td>21</td>
</tr>
<tr>
<td>3 Properties, limitations and optimisation of the DEGRA technique</td>
<td>23</td>
</tr>
<tr>
<td>3.1 Introduction</td>
<td>23</td>
</tr>
<tr>
<td>3.2 Graphical representation; function of the two γ-energies</td>
<td>25</td>
</tr>
<tr>
<td>3.2.1 Graphical representation</td>
<td>25</td>
</tr>
<tr>
<td>3.2.2 Mass absorption coefficients</td>
<td>29</td>
</tr>
<tr>
<td>3.2.3 Shape of the triangle; function of the two γ-energies</td>
<td>31</td>
</tr>
<tr>
<td>3.3 Statistical uncertainty in the mass flow rates</td>
<td>35</td>
</tr>
<tr>
<td>3.3.1 Introduction</td>
<td>35</td>
</tr>
<tr>
<td>3.3.2 Uncertainty in the fractions</td>
<td>39</td>
</tr>
<tr>
<td>3.3.3 Uncertainty in the velocities</td>
<td>47</td>
</tr>
<tr>
<td>3.4 Differences between actual and calibration circumstances</td>
<td>49</td>
</tr>
<tr>
<td>3.4.1 Introduction</td>
<td>49</td>
</tr>
<tr>
<td>3.4.2 Temperature and pressure</td>
<td>51</td>
</tr>
<tr>
<td>3.4.3 Salinity</td>
<td>53</td>
</tr>
<tr>
<td>3.4.4 Miscellaneous</td>
<td>57</td>
</tr>
<tr>
<td>3.5 Non-logarithmic averaging</td>
<td>59</td>
</tr>
<tr>
<td>3.5.1 Introduction</td>
<td>59</td>
</tr>
<tr>
<td>3.5.2 Non-logarithmic averaging in bubble flow</td>
<td>63</td>
</tr>
<tr>
<td>3.5.3 Slug flow; limitations to the counting time</td>
<td>65</td>
</tr>
<tr>
<td>3.6 Concentration profile of the gas-phase</td>
<td>69</td>
</tr>
<tr>
<td>3.7 Measuring errors</td>
<td>71</td>
</tr>
<tr>
<td>3.8 Application of the DEGRA technique</td>
<td>73</td>
</tr>
<tr>
<td>3.8.1 Introduction</td>
<td>73</td>
</tr>
<tr>
<td>3.8.2 Wall material</td>
<td>75</td>
</tr>
<tr>
<td>3.8.3 Detector</td>
<td>77</td>
</tr>
<tr>
<td>3.8.4 Source</td>
<td>81</td>
</tr>
<tr>
<td>3.9 Conclusions</td>
<td>85</td>
</tr>
<tr>
<td>4 Measurement of velocities with a venturi in non homogeneous flow</td>
<td>87</td>
</tr>
<tr>
<td>4.1 Introduction</td>
<td>87</td>
</tr>
<tr>
<td>4.2 The constant slip model</td>
<td>89</td>
</tr>
<tr>
<td>4.3 Discussion of the constant slip model</td>
<td>95</td>
</tr>
</tbody>
</table>
Crude oil production is normally accompanied by gaseous hydrocarbons and varying proportions of water. Measurements of the flow rates of hydrocarbon production from each well in a field are required for the purpose of reservoir management and production allocation. Current practice is to feed sequentially the outputs from each well to a common test separator system. Developments of smaller fields are only profitable if costs per produced barrel of oil can be reduced. Replacement of the bulky and expensive test separator with smaller and cheaper flow meters could make marginal field development projects economically viable (Ashkure and Hill, 1985; Barson et al., 1993; Jamieson et al., 1985).

A new instrument, the In-Line Separator (ILS), is developed at Shell Exploration and Production Laboratory (KSEPL) (Nales, 1991, limited distribution). The ILS separates roughly the production in a wet-gas and a gassy-liquid stream. The latter should have a Gas Volume Fraction (GVF) of less than 30%. The two streams are measured separately and combined again. Instruments for flow rate and composition measurement of the gassy-liquid stream are not yet commercially available and are a separate project at KSEPL. Both theoretical and experimental work done within that project are discussed in this report.

The essential parameters are volume fraction and individual velocity of each of the three phases. One of the major problems in multi-phase flow measurement is that no instruments are available that are capable of measuring the individual velocities, because these velocities are most likely not equal. The situation is greatly simplified if the mixture can be treated as a homogeneous fluid with one velocity. This situation is later on referred to as homogeneous flow, each phase being equally distributed and each phase having the same velocity profile. Measuring the flow rates then reduces to measuring the volume proportions and the one average fluid velocity. The latter can be performed by various single-phase instruments, provided the densities of the three phases are known.

Homogeneous flow rarely occurs. However, for the ILS application with the low gas volume fraction and with the gas dispersed in the liquid, the fluid will be assumed to be homogeneous. Further comment on this assumption is given in chapter 4. Also deviations from homogeneity and experimental checks will be discussed.

A summary of the instrument requirements for the ILS application is:

1. composition:
   * Water Cut (WC): 0 to 100%;
   * GVF: 0 to 30%;

2. velocity (in a 3" line):
   * velocity: 0.014 to 1.4 m s⁻¹ (≈5.34–534 m³/day);
   * Reynolds number: 70 to 10⁶.
Figure 1.1: Measurement of the individual mass flow rates in three-phase oil-water-gas flow combining a DEGRA composition measurement with a venturi velocity measurement.
The study by R. Nales (1991, limited distribution) resulted in the following choices (see figure 1.1).

* Composition measurement: the Dual Energy Gamma-Ray Absorption (DEGRA) technique, deriving the composition from the absorption of two different γ-energies.

The only good alternative, an impedance-density measurement, shows still large errors, especially when the liquid is water continuous (Dykesteen et al., 1985).

* Velocity measurement: venturi-tube, deriving the fluid velocity from a pressure drop caused by an areal change.

The advantages over other instruments are the low permanent pressure loss and the insensitivity to gas.

This report presents theoretical and experimental work on this measuring principle. The objectives are as follows.

1. Investigate the properties of the DEGRA technique. Several articles have been published on the principle of the DEGRA technique (Rafa, 1989; Nuland et al., 1991; Rebgetz et al. 1991). These publications do not give a clear and complete picture on optimal configurations (e.g. which detectors, what type of sources, etc.), limitations and errors.

2. Test the feasibility of a combined $^{109}$Cd–$^{152}$Gd source with dedicated γ-ray filters for composition measurements.

Z. I. Kolar recommended to use a combined $^{109}$Cd–$^{152}$Gd source with a filtering technique (Kolar, 1991). The source has been tested in various Oil-Water-Gas (OWG) mixtures using different detectors.

3. Test the DEGRA composition measurement in combination with a venturi velocity measurement assuming homogeneous flow.

Measurements have been done to investigate the practical problems attached to the DEGRA technique in dynamic systems and to test the viability of the assumption of homogeneity. These tests were conducted in a flow loop as well as in the field.

The flow loop tests were located at KSEPL. The field test was conducted at the NAM location in Berkel. The experiments covered the period of September 1992 to June 1993.

This report covers the graduation work of the author at:
Delft, University of Technology;
Department of Applied Physics;
Kramers Laboratorium voor Fysische Technologie;
Section: Transport Phenomena;
Sub-Section: Fysische Technologie.
Professor: Prof. dr. ir. H. E. A. van den Akker.
Mentors: Ir. A. M. Scheers (KSEPL);
Dr. R. F. Mudde (TU Delft).
In addition the name of Ir. Z. I. Kolar should be mentioned who greatly contributed to the contents of this report.

---

1 In this report consistently the term γ-radiation or γ-photon is used even when reference is made to X-rays.
2 PRINCIPLE OF THE MEASURING METHOD

2.1 Three-phase composition measurement using two γ-energies

In this section the equations are derived for three-phase composition measurements using the absorption of γ-radiation of two different energies. For a more detailed derivation, reference is made to the report by Z. I. Kolar (1991).

2.1.1 General absorption formula

The intensity of a narrow, parallel beam of mono-energetic γ-rays passing through matter is (Knoll, 1992):

\[ I(E) = I_i(E) e^{-\frac{\mu}{\rho}x} \]  (2.1)

with \( E \) - energy of the γ-rays [keV];
\( I(E) \) - intensity of the transmitted radiation of energy \( E \) [photons s\(^{-1}\)];
\( I_i(E) \) - intensity of the incident radiation of energy \( E \) [photons s\(^{-1}\)];
\( \mu \) - linear absorption coefficient [m\(^{-1}\)];
\( \rho \) - density [kg m\(^{-3}\)];
\( x \) - density thickness [kg m\(^{-2}\)].

The quotient \( [\frac{\mu}{\rho}] \), the mass absorption coefficient [m\(^2\) kg\(^{-1}\)], is a material property, determined by its composition and the energy of the γ-photons. The mass absorption coefficient of a chemical compound or a mixture can be evaluated from the coefficients \( [\frac{\mu}{\rho}]_i \) of the constituent elements according to the weighed average:

\[ [\frac{\mu}{\rho}] = \sum_{i=1}^{i=N} w_i [\frac{\mu}{\rho}]_i \]  (2.2)

with \( w_i \) - proportion by weight of the \( i \)th constituent out of \( N \) constituents [-].

The density thickness \( x \) is the product of linear thickness and density and depends on temperature, pressure, etc.

With actual measurements only part of the transmitted photons is registered. This part, determined by the efficiency of the detector \( \eta(E) (0 \leq \eta(E) \leq 1) \), depends on the energy of the photons. The count rate, the number of photons registered per second, therefore is:

\[ R(E) = I(E) \eta(E) \]  (2.3)

with \( R(E) \) - count rate at energy \( E \) [counts s\(^{-1}\)];
\( \eta(E) \) - detector efficiency at energy \( E \) [counts photon\(^{-1}\)].
2.1.2 Count rate through a pipe with OWG mixtures

When $\gamma$-radiation is transmitted through a pipe containing a mixture of oil, water and gas, the intensity is given by equation 2.1, with:

$$\frac{[\mu]}{\rho} x = \frac{[\mu]}{\rho} \rho_p t_p + ([\mu]_o \rho_o \alpha_o + [\mu]_w \rho_w \alpha_w + [\mu]_g \rho_g \alpha_g) t_f$$  (2.4)

with $\alpha_x$ - volume fraction water, oil, gas along the path of the beam [-];
$\rho_t$ - path length through the pipe wall, i.e. twice the wall thickness [m];
$\rho_f$ - path length through the fluid [m].

The logarithm of the count rate then is, combining the equations 2.1 to 2.4:

$$\ln(R(E)) = \ln(R_i(E)) - \left(\frac{[\mu]}{\rho} \rho_p t_p - ([\mu]_o \rho_o \alpha_o + [\mu]_w \rho_w \alpha_w + [\mu]_g \rho_g \alpha_g) t_f\right)$$  (2.5)

with $R_i(E)$ - count rate in the absence of any absorbing material ($=\eta(E)I_i(E)$) [counts s$^{-1}$].

When there is no fluid in the pipe ($\alpha_w=0$, $\alpha_o=0$, $\alpha_g=0$) this reduces to:

$$\ln(R_v(E)) = \ln(R_i(E)) - \left(\frac{[\mu]}{\rho} \rho_p t_p\right)$$  (2.6)

with $R_v(E)$ - count rate corresponding to empty pipe (vacuum) [counts s$^{-1}$].

For a pipe completely filled with oil ($\alpha_o=1$, $\alpha_w=0$, $\alpha_g=0$) equation 2.5, using equation 2.6, reduces to:

$$\ln(R_o(E)) = \ln(R_v(E)) - \left(\frac{[\mu]}{\rho} \rho_o t_f\right)$$  (2.7)

with $R_o(E)$ - count rate when the pipe is filled with oil [counts s$^{-1}$].

Similar equations hold for water and gas. These equations can be used to rewrite equation 2.5. The count rate, measured when radiation is transmitted through a pipe containing a mixture of oil, water and gas, is then given by:

$$\ln(R(E)) = \ln(R_o(E)) \alpha_o + \ln(R_w(E)) \alpha_w + \ln(R_g(E)) \alpha_g.$$  (2.8)

---

1 The logarithm in this report always refers to the natural logarithm based on $e$ ($=2.71828182845...$).
2.1.3 Working equation

Three independent equations are required to calculate the three fractions, \( a_o \), \( a_w \), and \( a_g \). In a closed system containing just oil, water and gas, one equation is:

\[ a_o + a_w + a_g = 1. \]  \hspace{1cm} (2.9)

Two additional equations can be obtained from equation 2.8, using two different \( \gamma \)-energies.

A complete set of linear equations for the composition along the path of the \( \gamma \)-photons in a closed oil-water-gas system is:

\[
\begin{bmatrix}
\ln(R_o(E_1)) & \ln(R_w(E_1)) & \ln(R_g(E_1)) \\
\ln(R_o(E_2)) & \ln(R_w(E_2)) & \ln(R_g(E_2)) \\
1 & 1 & 1
\end{bmatrix}
\begin{bmatrix}
a_o \\
a_w \\
a_g
\end{bmatrix}
=
\begin{bmatrix}
\ln(R(E_1)) \\
\ln(R(E_2)) \\
1
\end{bmatrix} \hspace{1cm} (2.10)
\]

with \( E_{1,2} \) - \( \gamma \)-energy 1,2 [keV].

The matrix elements are measured filling up the system subsequently with oil, water and gas. These measurements will be later on referred to as calibrations or calibration measurements. The count rates at the two \( \gamma \)-energies then provide sufficient information to calculate the three volume fractions:

\[
a_o = \frac{1}{D} \left[ (M_1 - W_1) (G_2 - W_2) - (M_2 - W_2) (G_1 - W_1) \right]
\]

\[
a_w = \frac{1}{D} \left[ (M_1 - W_1) (O_2 - G_2) - (M_2 - G_2) (O_1 - G_1) \right] \hspace{1cm} (2.11)
\]

\[
a_g = \frac{1}{D} \left[ (M_1 - W_1) (W_2 - O_2) - (M_2 - W_2) (W_1 - O_1) \right]
\]

with \( O, W, G_{1,2} \) - logarithm of the count rate of the oil, water, gas calibration at \( \gamma \)-energy 1,2 [ln(counts s\(^{-1}\))];

\( M_{1,2} \) - logarithm of the count rate measured at \( \gamma \)-energy 1,2 [ln(counts s\(^{-1}\))];

\( D \) - determinant of the matrix to the left hand side of equation 2.10, given by:

\[ D = (O_1 - W_1)(G_2 - W_2) - (O_2 - W_2)(G_1 - W_1) \left[ (\ln(\text{counts s}^{-1}))^2 \right]. \]
2.2 Measuring velocity with a venturi in homogeneous incompressible flow

The venturi-tube (after the Italian physicist and philosopher Giovanni Battista Venturi (1746-1822)) is a widely applied instrument in single-phase and high quality two-phase flow. Several articles derive and discuss the basic equations of a venturi (Cheremisinoff, 1988). The results are given below.

The venturi-tube derives the flow rate from a pressure difference caused by an areal change. In single-phase incompressible flow the relation is:

\[ Q = C_D \frac{A_2}{\sqrt{1 - \left(\frac{A_2}{A_1}\right)^2}} \sqrt{\frac{2(\Delta p - \rho_f g \Delta h)}{\rho_f}} \]  

(2.12)

with:
- \( Q \) - total volume flow rate \([m^3 s^{-1}]\);
- \( C_D \) - discharge coefficient [-];
- \( A_1,2 \) - area inlet(1), throat(2) of the venturi \( [m^2] \);
- \( \Delta p \) - absolute pressure difference between inlet and throat of the venturi \( [kg \ m^{-1} \ s^{-2}] \);
- \( \rho_f \) - fluid density \( [kg \ m^{-3}] \);
- \( g \) - acceleration of gravity \( [m \ s^{-2}] \);
- \( \Delta h \) - vertical distance between the two legs of the pressure cell \( [m] \).

\( C_D \), the discharge coefficient \((0\leq C_D \leq 1)\) accounts for friction and velocity distribution influences. In single-phase flow these are determined by the Reynolds number \((Re)\). Equation 2.12 thus relates the flow rate to the pressure drop, provided the fluid properties (viscosity, density) and a calibration curve for the discharge coefficient are known.

Equation 2.12 also holds in homogeneous incompressible three-phase flow. The fluid density is:

\[ \rho_f = \alpha_o \rho_o + \alpha_w \rho_w + \alpha_g \rho_g \]  

(2.13)

For the discharge coefficient an approximate value has to be taken as the viscosity of the OWG mixture is unknown.

The individual mass flow rates then are:

\[ m_i = \alpha_i \rho_i Q \]  

(2.14)

with:
- \( i \) - index for oil, water and gas [-];
- \( m_i \) - mass flow rate \([kg \ s^{-1}]\).

In chapter 4 three-phase compressible equivalent of equation 2.12 will be derived. The differences however are small if the pressure drop is low and the line pressure high. Chapter 4 also discusses influences of and corrections for deviations from homogeneity.
2.3 Conclusions

* The equations 2.11 to 2.14 represent a complete system for measuring the individual mass flow rates in three-phase flow combining a DEGRA composition measurement with a venturi velocity measurement, provided homogeneity and incompressibility can be assumed. The procedure is as follows:
  + the two count rates, one at $E_1$ and the other at $E_2$, give the three volume fractions (equation 2.11) and thus the fluid density (equation 2.13);
  + the pressure drop gives, using the fluid density that follows from the composition measurement, the total volume flow rate (equation 2.12) and thus, combined with the measured volume fractions, the three individual mass flow rates (equation 2.14).

# The equations for DEGRA composition measurements are straightforward. The choice of a system however is determined by further theoretical considerations (e.g. which $\gamma$-energies are optimal) and practical considerations (e.g. which sources and detectors are practically applicable). These will be discussed in the next chapter.
3 PROPERTIES, LIMITATIONS AND OPTIMISATION OF THE DEGRA TECHNIQUE

3.1 Introduction

Dual energy γ-ray absorption techniques for the on-line analysis of materials were developed to determine the mass fractions of two component mixtures such as lead in mineral slurries (Watt, 1967) and ash in coal (Kato, 1967). In 1977 Fanger et al. showed that DEGRA measurements can determine the volume fractions of three components in a closed system such as a pipe. Several articles since then have been published on this subject (Abouelwafe and Kendall, 1980; Tomada et al., 1987, the articles mentioned in chapter 1). None of the articles however gives a clear and complete description of properties, limitations and optimal configurations of the DEGRA technique.

The objective of this chapter therefore is to present a general discussion of the properties of the DEGRA technique in dynamic systems. First, a graphical representation of the composition determination will be introduced. This representation will be used to illustrate the principle of the DEGRA technique and the influence of the different errors. A discussion of the main sources of error eventually results in the limitations of the DEGRA technique and in optimisation criteria.
Figure 3.1: Composition triangle.
The oil, water and gas calibration make up a triangle. Every possible composition represents a point within the triangle. The figure shows the lines having equal oil, water and gas fraction with steps of 25%. Two measured count rates, indicated by M, can be translated into a composition via the procedure explained in the text.
3.2 Graphical representation; function of the two γ-energies

In section 2.1 the equation is derived, necessary to calculate the volume fractions from the absorption of γ-radiation of two different energies (equation 2.10). This section presents a graphical equivalent of this equation.

3.2.1 Graphical representation

Dual energy γ-ray absorption techniques determine the composition of oil-water-gas mixtures from two measured parameters: ln(R(E1)) and ln(R(E2)) (see equation 2.11). This implies that, in a graph with ln(R(E1)) on the x-axis and ln(R(E2)) on the y-axis, every different composition represents a different point. Solving the three fractions from equation 2.11 corresponds in this graph to a simple procedure that is explained below.

Three points in the graph with ln(R(E1)) on the x-axis and ln(R(E2)) on the y-axis follow from the calibrations: 100% oil, 100% water and 100% gas. These will be denoted by O, W and G respectively. W and G represent two points with 0% oil. Because of the linear dependency between the fractions and ln(R(E1)) and ln(R(E2)), any point on the straight line connecting these points corresponds to 0% oil. The scale is linear, from 100% water and 0% gas in W to 0% water and 100% gas in G. Lines of constant oil fraction are parallel to this line. Analogue reasonings hold for water and gas. This results in a triangle as is drawn in figure 3.1. The composition triangle.

Two count rates, one at E1 and the other at E2, resulting from a measurement represent a point M within the triangle. The oil fraction follows from the crossing of the line of constant oil fraction through M (the line parallel to WG), with OG or OW. Similar procedures hold for the water and gas fraction. Figure 3.1 illustrates an example having equal oil, water and gas fractions.

The calibrations determine the three vertices that define the composition triangle. The co-ordinates of the oil calibration are:

\[ (x, y)_o = (\ln(R_o(E_1)), \ln(R_o(E_2))) \]  

With equation 2.7 this is rewritten to:

\[ (x, y)_o = (\ln(R_v(E_1)), \ln(R_v(E_2))) - t_{\rho_o}[\frac{1}{\rho}_1, \frac{1}{\rho}_2] \]  

Replacing the index o by w and g gives the co-ordinates of the water and gas calibration respectively.

These equations reveal some properties of the triangle.
1. The two vacuum count rates, thus source strength, detector efficiency, wall material and thickness, only influence
the position of the triangle in the graph, not the shape and the cross-sectional area.
The reason is that the first term on the right hand side, representing the two vacuum count rates, is the same for all three calibrations. This means that a change of (one of) the vacuum count rates is equivalent to a translation of the whole triangle. The vacuum count rates depend on a particular measuring configuration. Therefore this term will usually be subtracted, using \( \ln\left(\frac{R(E_i)}{R(E_i)}\right) \) instead of \( \ln(R(E_i)) \).

2. The length of the fluid path \( t_f \) only influences the cross-sectional area of the triangle, not the shape. The reason is that the last term on the right hand side is multiplied by \( t_f \). An increase (decrease) in \( t_f \) therefore causes the triangle to stretch (shrink) without change of shape.

3. The densities and the mass absorption coefficients of the three substances determine the shape of the triangle as the shape is independent of \( t_f \) and the vacuum count rates.

Shape and cross-sectional area of the triangle are indications for the sensitivity to errors of the composition measurement.
* Shape: Shifting \( W \) to a point close to \( O \) (see figure 3.1) results in a long, narrow triangle. A small error in the co-ordinates of \( M \) then causes large errors in the fractions. The extreme is that the three calibrations are on one straight line. This corresponds to the situation that the two absorption equations in equation 2.10 are dependent. Determining the composition is then impossible.
* Cross-sectional area: the influence of an error vector, the difference between the co-ordinates of the measured composition and the co-ordinates of the real composition, decreases if the area increases.

The only way to influence the shape and area of the triangle and thus the sensitivity to errors is to change the mass absorption coefficients as the densities and the length of the fluid path usually are fixed. The next section therefore discusses the mass absorption coefficient.
Figure 3.2: Mass absorption coefficients (Hubbel, 1982).
3.2.2 Mass absorption coefficients

The mass absorption coefficient depends on the energy of the photons and the chemical composition of the absorber (see section 2.1.1). Table 3.1 presents the approximate compositions of oil, water and gas.

Table 3.1: Composition of oil, water and gas in weight fraction.

<table>
<thead>
<tr>
<th></th>
<th>H</th>
<th>C</th>
<th>O</th>
<th>N</th>
<th>Na</th>
<th>Cl</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil</td>
<td>15</td>
<td>85</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>H₂O</td>
<td>11</td>
<td>-</td>
<td>89</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Brine (150 kg NaCl m⁻³)</td>
<td>10</td>
<td>-</td>
<td>77</td>
<td>-</td>
<td>5</td>
<td>8</td>
</tr>
<tr>
<td>Associated gas</td>
<td>20</td>
<td>76</td>
<td>2</td>
<td>2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Wet gas</td>
<td>16</td>
<td>80</td>
<td>2</td>
<td>2</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Figure 3.2 shows the mass absorption coefficient of the most relevant elements as a function of the energy of the photons. Notice the following remarks:

1. the mass absorption coefficient is a decreasing function of energy (in this energy region);
2. the mass absorption coefficient of water at low γ-energies (determined by O or, if there is salt present, by Cl) is higher than the mass absorption coefficient of oil or gas (determined by C);
3. the mass absorption coefficients of Cl, Na, O and C are for higher γ-energies equal, and half the mass absorption coefficient of H.

The reason for the latter one is that the interaction of γ-photons of higher energies (up to a limit > 1 MeV) with electrons is independent of the element to which the electron is bound. H has only one electron per u (atomic mass unit). Cl, Na, O and C all have approximately one electron per two us.

The above remarks are important for optimisation and accuracy considerations that will follow.
3.2.3 Shape of the triangle; function of the two $\gamma$-energies

The shape of the composition triangle is entirely determined by density and mass absorption coefficient of the three phases (see section 3.2.1). The densities are fixed and generally the following holds: $\rho_c > \rho_w > \rho_g$. The characteristics of the triangle then follow from the properties of the mass absorption coefficient given in the section above.

Calibrations of substance $i$ ($i$ stands for oil, water or gas) with different densities lie on the straight line through $(0,0)$ with slope $\left[ \frac{\mu}{\rho} \right]_i \frac{E_2}{\left[ \frac{\mu}{\rho} \right]_i E_1}$ (see equation 3.2). The slope is smaller than 1 as the mass absorption coefficient is a decreasing function of energy ($E_1 < E_2$).

The slopes of the gas and oil calibrations are approximately equal for all energy pairs because of their similar composition (see table 3.1).

For the slope of the line through $(0,0)$ and the water calibration point there are two different situations.

1. $E_1$ and $E_2$ are high: the slopes of the oil and the water calibrations are the same, all three calibrations lie on one straight line.

The reason is that, for higher $\gamma$-energies, the mass absorption coefficient of water and oil only differ by a constant factor, the quotient of their electron densities. If $E_1$ and $E_2$ are high, this factor disappears in the quotient $\left[ \frac{\mu}{\rho} \right]_i \frac{E_2}{\left[ \frac{\mu}{\rho} \right]_i E_1}$.

Three calibrations on one straight line corresponds to the situation that two of the three equations in equation 2.10 are dependent. This also can be shown analytically: for higher energies, equation 2.8 can be rewritten to:

$$\ln \left( \frac{R(E_i)}{R_g(E_i)} \right) = \left[ \frac{\mu}{\rho} \right]_{e} t_f (\rho_{eo} \alpha_o + \rho_{ew} \alpha_w + \rho_{eg} \alpha_g)$$

with $\left[ \frac{\mu}{\rho} \right]_{e}$ - mass absorption coefficient of electrons [m$^2$ kg$^{-1}$];

$\alpha_o, \alpha_w, \alpha_g$ - electron density of oil, water, gas [kg m$^{-3}$].

If $E_1$ and $E_2$ are high, both equations have the above shape, thus are dependent. Solving the fractions then is impossible.

2. $E_1$ is low and $E_2$ is high: the slope of the line through $(0,0)$ and the water calibration is smaller than the slope of the oil calibration.

The reason is that at $E_2$, the mass absorption coefficients of oil and water are approximately the same, while at $E_1$, the mass absorption coefficient of water is much higher (see figure 3.2).

\(^1\) The graph is discussed with $\ln(R(E_i)/R_g(E_i))$ on the x-axis and $\ln(R(E_o)/R_g(E_i))$ on the y-axis (see section 3.2.1).
Figure 3.3: Function of the two $\gamma$-energies.

A - Salinity=0 kg m$^{-3}$; B - Salinity=300 kg m$^{-3}$.

Determining the composition is only possible if $E_1$ is sufficiently low to be able to discriminate between the elements of water and the elements of oil and gas so between O and C if there is no salt (A) or between Cl and C if the water contains salt (B). The length of the fluid path equals 5 cm. For a different $t_e$ the scaling of both x- and y-axis should be multiplied by the quotient of the new and the old $t_e$. 
The actual position of the calibrations is in the third quadrant as length of the fluid path, density and mass absorption coefficient are positive (see equation 3.2). The gas calibration is much closer to (0,0) than the oil calibration because of its small density. The oil calibration again is closer to (0,0) than the water calibration because water (usually) has a larger density and mass absorption coefficient.

Figure 3.3 shows the transition from both \( \gamma \)-energies high to one energy low and one energy high. Figure 3.3 A for no salt and figure 3.3 B for a salinity\(^1\) of 300 kg m\(^{-3}\). \( t_f = 5 \) cm, adjusting the graph for a different \( t_f \) is performed by multiplying the \( x \)- and \( y \)-scale by the quotient of the new and the old \( t_f \).

The DEGRA technique derives the three fractions from three equations. One follows from the fact that a pipe is a closed system. The remaining two follow from the absorption of \( \gamma \)-radiation of two different energies. The system only can be solved if these two equations are independent, i.e. measure something different. From the above discussion follows that the two functions are:

* \( E_1 \), the low \( \gamma \)-energy: measure O, or if there is some salt Cl concentration;
* \( E_2 \), the high \( \gamma \)-energy: measure electron density.

The different sources of error determine the exact choice of \( E_1 \) and \( E_2 \). These are presented in the next sections.

\(^1\) The salinity is given in kilograms NaCl equivalents per cubic meter brine. Concentration and atomic number of salts different from NaCl are low.
3.3 Statistical uncertainty in the mass flow rates

Radioactive decay is a statistical process. Apart from measuring errors there is still an uncertainty in the count rates. This section discusses the influence of this uncertainty on the mass flow rates.

3.3.1 Introduction

The emission, absorption and detection of γ-radiation are statistical processes, described by the Poisson distribution. A count rate resulting from a measurement has therefore some uncertainty. An estimate for the magnitude of this uncertainty follows from the properties of the Poisson distribution (Mood and Graybill, 1963).

The standard deviation (σ) of a Poisson distribution is the square root of the mean. The best estimate for the standard deviation of a measured number of counts is the square root. When the mean is large (>15) the Poisson distribution can be approximated by a normal distribution. The chance that the outcome of one measurement is between the mean and plus or minus the standard deviation is then 69%. This interval, the 1σ interval of confidence, will be used in the further discussion.

The uncertainty in the count rate, if the above approximations hold, is:

$$\Delta R(E) = \sqrt{\frac{R(E)}{\tau}}$$

(3.4)

with $\tau$ - counting time [s];
$\Delta R(E)$ - estimated uncertainty the count rate [counts s^{-1}].

This in turn causes an uncertainty in the logarithm of the count rate:

$$\Delta \ln(R(E)) = \frac{1}{\tau R(E)}$$

(3.5)

with $\Delta \ln(R(E))$ - estimated uncertainty in the logarithm of the count rate [ln(counts s^{-1})].

The counting time stands in the denominator. Counting times should be kept short in order to reduce systematic errors (see section 3.5). The influence of the statistical uncertainty on the three measured mass flow rates therefore can not be neglected.

The three individual mass flow rates are calculated with the equations 2.11 to 2.14 if homogeneous incompressible flow is assumed or, if corrections for inhomogeneity are incorporated
(see chapter 4), with the equations 2.11, 4.2, 4.12 and 4.13. Uncertainties in the measured count rates therefore affect the calculated mass flow rate in two (linked) ways:
1. uncertainties in the fractions;
2. uncertainties in the velocity or velocities.

The following sections discuss the order of magnitude of the uncertainty as a function of the two $\gamma$-energies and their strength. In addition the influence of the two most important parameters, salinity and length of the $\mu^\mathrm{d}$ path will be discussed. The results will be illustrated by examples. Some general data for these examples are:

<table>
<thead>
<tr>
<th>Temperature</th>
<th>50 °C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure</td>
<td>5 bar</td>
</tr>
<tr>
<td>Water:</td>
<td></td>
</tr>
<tr>
<td>Salinity</td>
<td>150 kg m$^{-3}$</td>
</tr>
<tr>
<td>Oil:</td>
<td></td>
</tr>
<tr>
<td>Density at 15°C</td>
<td>900 kg m$^{-3}$</td>
</tr>
<tr>
<td>Composition</td>
<td>15 wt% H</td>
</tr>
<tr>
<td></td>
<td>85 wt% C</td>
</tr>
<tr>
<td>Gas:</td>
<td></td>
</tr>
<tr>
<td>Molar mass</td>
<td>29 kg kmol$^{-1}$</td>
</tr>
<tr>
<td>Composition</td>
<td>20 wt% H</td>
</tr>
<tr>
<td></td>
<td>80 wt% C</td>
</tr>
<tr>
<td>Pipe:</td>
<td></td>
</tr>
<tr>
<td>Density</td>
<td>1420 kg m$^{-3}$</td>
</tr>
<tr>
<td>Composition</td>
<td>25 wt% H</td>
</tr>
<tr>
<td></td>
<td>75 wt% C</td>
</tr>
<tr>
<td>$r_f$</td>
<td>5 cm</td>
</tr>
<tr>
<td>$r_p$</td>
<td>0.4 cm</td>
</tr>
</tbody>
</table>

$I_{1}(E_1) \cdot r$  
(= Mean number of photons of $\gamma$-energy 1 that falls on the detector in absence of any absorbing material in the chosen measuring time)

$I_{1}(E_2) \cdot r$  

$\eta(E)$  

1
Figure 3.4: Uncertainty area around a measured composition. 
E₁=30 keV, E₂=300 keV, salinity=150 kg m⁻³, tₓ=5 cm, 
R₁(E₁,₂)ₚ=5000 counts. The measured composition is: αₓ=αₓ=αₓ=33%. 
3.3.2 Uncertainty in the fractions

Uncertainties in the count rates result, in the composition triangle, in an error interval around the measured x and y co-ordinate. Figure 3.4 shows an example with $E_1=30$ keV, $E_2=300$ keV, a measured composition of 1/3 oil, 1/3 water and 1/3 gas and the data from section 3.3.1.

Notice that the upper left and bottom right point of the error area determine the uncertainty in the composition. This is independent of composition, length of the sides and exact shape of the triangle, provided it keeps the general shape discussed in section 3.2. The sign of the error in the oil fraction in the upper left and bottom right points is opposite to that in the water and gas fraction. The absolute statistical uncertainty in the oil fraction is thus larger than that in the water and gas fraction.

The absolute uncertainty in the oil fraction in this example is 6.9%. The count rates have a relative accuracy of 2.9% and 1.8% respectively.

The formulas for the uncertainty in each fraction due to two independent uncertainties in the two count rates can be derived from equation 2.11 (Rebgetz et al., 1991):

$$\Delta a_i = \left( \frac{\partial a_i}{\partial M_1} \right)^2 \Delta M_1^2 + \left( \frac{\partial a_i}{\partial M_2} \right)^2 \Delta M_2^2$$

so:

$$\Delta a_o = \frac{1}{|D|} \left[ (G_r - W_r)^2 \Delta M_1^2 + (G_1 - W_1)^2 \Delta M_2^2 \right]$$
$$\Delta a_w = \frac{1}{|D|} \left[ (O_r - W_r)^2 \Delta M_1^2 + (O_1 - W_1)^2 \Delta M_2^2 \right]$$
$$\Delta a_g = \frac{1}{|D|} \left[ (O_r - W_r)^2 \Delta M_1^2 + (O_1 - W_1)^2 \Delta M_2^2 \right]$$

with $\Delta a_{o,w,g}$ - uncertainty in the oil, water, gas fraction [-]; $|D|$ - absolute value of the determinant of the matrix to the left hand side of equation 2.10.

To reduce the number of pictures the following measure for the total uncertainty in the fractions is defined:

$$\Delta a = \sqrt{(\Delta a_o^2 + \Delta a_w^2 + \Delta a_g^2)}$$

with $\Delta a$ - measure for the total uncertainty in the fractions [-].

Not much of the information on the uncertainties in the individual fractions is lost as they are strongly coupled (see figure 3.4): a large uncertainty in the oil fraction has to be accompanied by large uncertainties in water and gas fraction.
Figure 3.5: Uncertainty in the fractions as a function of the value of the two $\gamma$-energies. 
A - 100% oil; B - 100% water
Contour lines connect energy pairs with equal $\Delta \alpha$. $\Delta \alpha$ is given in procents. Salinity=150 kg $m^{-3}$, $t_c=5$ cm, $R_1(E_{1,2})\tau=5000$ counts. Further data can be found in section 3.3.1.
An expression for $\Delta \alpha$ is derived from equation 3.7:

$$
\Delta \alpha = \frac{1}{|D|} \sqrt{ \left( (G_2 - W_2)^2 + (O_2 - G_2)^2 + (O_2 - W_2)^2 \right) \Delta M_1^2 + \left( (G_1 - W_1)^2 + (O_1 - G_1)^2 + (O_1 - W_1)^2 \right) \Delta M_2^2 } \quad (3.9)
$$

with $\Delta M_{1,2}$ - uncertainty in the logarithm of the count rate measured at $\gamma$-energy 1,2 [ln(counts s$^{-1}$)].

Notice the following properties.

1. Uncertainties in the logarithm of the count rates are multiplied by a factor that is:
   * independent of the vacuum count rates, i.e. source strength, wall material and thickness, detector efficiency, etc.;
   * inversely proportional to length of the fluid path;
   * further only dependent on the densities of the three components and their mass absorption coefficients.

The reason is that differences between the logarithm of the count rate of two calibrations are independent of the vacuum count rates and proportional to the length fluid path (see equation 2.7 and compare section 3.2.1).

2. The uncertainty in the logarithm of the count rate at $E_2$ is multiplied by a factor that is larger than the factor at $E_1$. The reason is that differences between the logarithm of the count rate of two calibrations (usually) increase with decreasing $\gamma$-energy (see figure 3.2). Equation 3.9 shows that the uncertainty in the logarithm of the count rate at $E_2$ is multiplied by the differences between the logarithm of the count rates of the calibrations at $E_1$ and visa versa.

3. The uncertainty in the oil fraction contributes most to $\Delta \alpha$ (as was shown graphically above) because $(W_i - G_i)$, originating from the uncertainty in the oil fraction (see equation 3.6), is larger than $(O_i - G_i)$ or $(W_i - O_i)$ (see section 3.2.2).

4. Absorption in the wall only decreases the count rate so increases the statistical uncertainties.

5. $\Delta \alpha$ depends on the composition as the $\Delta M_i$ depend on the composition.

Equation 3.7 gives a mean to calculate the magnitude of the uncertainty in the fractions for any situation. The following data are necessary:
   * $E_{1,2}$;
   * $I_1(E_{1,2}) \cdot \tau$;
   * detector efficiency as a function of $\gamma$-energy;
   * data on the situation, i.e. type of oil, water (salinity), gas, diameter pipe, etc.;
   * composition.
Figure 3.6: Contribution of the uncertainty at $E_1$ to the uncertainty in the fractions.
The part of the uncertainty in the fractions originating from the uncertainty at $E_1$ is plotted as a function of the value of $E_1$. $E_2=300$ keV, salinity=150 kg m$^{-3}$, $t_x=5$ cm, $R_i(E_1)=R_i(E_2)$. Further data can be found in section 3.3.1.

Figure 3.7: Influence of salinity on the uncertainty in the fractions for 100% water. Contour lines connect points with equal $\Delta \alpha$. The magnitude of $\Delta \alpha$ is given in percents. $E_2=300$ keV, $t_x=5$ cm, $R_i(E_{1,2})=5000$ counts. Further data can be found in section 3.3.1.
The influence of the most important variables, the value of the two energies, the (relative) strength of each energy, salt concentration and the length of the fluid path, on the uncertainty is discussed and illustrated below. The 100% water and 100% oil point have been chosen, because these are representative for the compositions expected in the ILS.

**Value of the two \(\gamma\)-energies**

Figure 3.5 illustrates the influence of the choice of the \(\gamma\)-energies on the uncertainty in the fractions, using the data from section 3.3.1. Figure 3.5 A for 100% water and B for 100% oil. \(\Delta\alpha\) is plotted as a function of the two \(\gamma\)-energies in a contour plot with \(E_1\) on the \(x\)-axis and \(E_2\) on the \(y\)-axis. The contour lines connect points with equal \(\Delta\alpha\). Contour lines are drawn for various \(\Delta\alpha\). The difference between the minimum and the maximum \(\Delta\alpha\) indicated is a factor four in counting time.

Figure 3.5 shows the general influences of the two energies.

1. The exact value of \(\gamma\)-energy 2 has little influence on the magnitude of the uncertainty, provided it is high: the general purpose of \(E_2\) is to measure (electron-) density. A wide range of \(\gamma\)-energies is thus possible (see section 3.2.2).

2. The choice of \(\gamma\)-energy 1 has a large influence on the magnitude of the uncertainty.
   * Contour lines for \(E_1\) lower than the optimum, i.e. minimal uncertainty, are very close: the purpose of the \(E_1\) is to discriminate between C of oil and gas and O or Cl of water. The contrast increases with decreasing energy. However, below some energy so little of the incident photons are transmitted that the advantage of a larger contrast is outweighed by the increase of statistical uncertainty. Below that point the lines are very close because this increase is several orders of magnitude larger than the increase in contrast.
   * Contour lines for \(E_1\) higher than the optimum are less close than for \(E_1\) lower: the increase in count rate because of higher energies partly compensates the decrease in contrast.

To obtain a precise measurement using as little source strength and time as possible in the whole target area of the triangle (WC 0-100\%, GVF 0-30\%), \(E_1\) should be chosen at (or slightly lower than) the optimum for 100% water, in this example at about 25 keV. The uncertainty for other compositions is then not much larger than in their optimum. For a precise measurement in some other part of the triangle, \(E_1\) should be chosen at the optimum for the point with the largest absorption at \(E_1\) expected (not necessarily 100% water).

**Strength of the two \(\gamma\)-energies**

Figure 3.6 shows the contribution of each \(\gamma\)-energy separately to the uncertainty in the fractions in the example given.
Figure 3.8: Influence of the fluid path on the uncertainty in the fractions.
A - 100% oil; B - 100% water
Contour lines connect points with constant $\Delta \alpha$. $\Delta \alpha$ is given in procents. $E_o=300$, salinity=150 kg m$^{-3}$, $R_s(E_{i,2}) \tau=5000$ counts. Further data can be found in section 3.3.1.
above. The fraction of the uncertainty that originates from \( E_i \) is plotted as a function of the lower energy. \( R_i(E_i)=R_i(E_2) \) and \( E_2 \) is chosen 300 keV as the value of \( E_2 \) is unimportant.

For \( E_2=25 \) keV (see above) and with high water fractions both \( \gamma \)-energies contribute approximately the same to the total uncertainty. The uncertainty at \( E_i \) decreases more if some gas and/or oil are present. The uncertainty in the fractions for most compositions therefore originates from the uncertainty in the count rate at \( E_2 \). If \( E_i \) is chosen following the procedure given above, it is therefore most profitable to increase the strength of \( E_2 \) in order to increase over-all precision.

Salinity

The salt concentration of production water ranges from close to 0 kg m\(^{-3}\) up to saturation corresponding to about 300 kg m\(^{-3}\). At low \( \gamma \)-energies, Cl is a strong absorber so salinity will be an important factor in the choice of the two \( \gamma \)-energies. The influence of an increase in salt concentration is two-fold:
1. the contrast between the elements of oil and gas and water increases;
2. the count rate decreases.

Figure 3.7 illustrates the influence of the two phenomena for 100% water. \( \Delta \alpha \) is plotted in a contour plot as a function of salinity and \( E_i \). \( E_2 \) equals 300 keV, the rest of the data, except for salinity, are taken from section 3.3.1.

For 100% water and thus for any composition, the increased contrast undoes the influence of the decreased count rate.

Length of the fluid path

In oil industry a wide range of pipe diameters is encountered. Dual energy \( \gamma \)-ray absorption measurements are limited in length of the fluid path, both to the high and the low side:
* a small \( t_r \) gives high count rates, the small uncertainty in the count rates however causes large uncertainties in the fractions because of the factor \( 1/t_r \) in the error formula;
* a large \( t_r \) results in much absorption and consequently in large uncertainties in the count rates.

Figure 3.8 illustrates the influence of the two phenomena. Figure 3.8 A for 100% water and B for 100% oil. \( \Delta \alpha \) is plotted in a contour plot as a function of \( E_i \) and the length of the fluid path. \( E_2 \) equals 300 keV, the rest of the data, except for \( t_r \), are taken from section 3.3.1.

The DEGRA technique is, from a statistical point of view eligible for fluid paths between 1 and 4 inches. Six inches as used by Rebgetz et al. (1991) is considered too large if high water fractions are expected.
Figure 3.9: Statistical uncertainty in fluid and liquid density as a function of $E_1$. $E_2=300$ keV, salinity=150 kg m$^{-3}$, $t_r=5$ cm, $R_i(E_{1,2})\tau=5000$ counts. Further data can be found in section 3.3.1.

Figure 3.10: Contribution of the uncertainty at $E_1$ to the uncertainty in fluid and liquid density. The fraction of the uncertainty in the densities originating from the uncertainty at $E_1$ is plotted as a function of the value of $E_1$. $E_2=300$ keV, salinity=150 kg m$^{-3}$, $t_r=5$ cm, $R_i(E_{1,2})\tau=5000$ counts. Further data can be found in section 3.3.1.
3.3.3 Uncertainty in the velocities

The equations that relate the velocities to the pressure drop, use information from the composition measurement:
1. fluid density if homogeneous incompressible flow is assumed (see section 2.2);
2. liquid density + gas volume fraction if corrections for compressibility and/or corrections for inhomogeneity are incorporated (see chapter 4).

Fluid and liquid density, \( \rho_f \) and \( \rho_l \), are given by equation 2.13 and equation 4.2 respectively. The uncertainties due to two independent uncertainties in the count rates are:

\[
\Delta \rho_f = \frac{1}{D} \left[ (\rho_o (G_2 - W_2) + \rho_w (O_2 - G_2) + \rho_g (O_2 - W_2))^2 \Delta M_1^2 
+ (\rho_o (G_1 - W_1) + \rho_w (O_1 - G_1) + \rho_g (O_1 - W_1))^2 \Delta M_2^2 \right]^{1/2} 
\]

\[
\Delta \rho_l = \frac{1}{D} \left[ \frac{\rho_w - \rho_o}{(\alpha_o + \alpha_w)^2} \left[ (\alpha_o (O_2 - G_2) - \alpha_w (G_2 - W_2))^2 \Delta M_1^2 
+ (\alpha_o (O_1 - G_1) - \alpha_w (G_1 - W_1))^2 \Delta M_2^2 \right]^{1/2} \right] 
\]

with \( \Delta \rho_i \) - uncertainty in fluid, liquid density [kg m\(^{-3}\)].

Figure 3.9 illustrates the influence of \( E_i \) on the uncertainties. \( \Delta \rho / \rho \) and \( \Delta \rho / \rho \) are plotted as a function of \( E_i \) for 100\% oil and 100\% water. \( E_2 \) equals 300 keV, further data are taken from section 3.3.1. Figure 3.9 shows that the uncertainty in the densities is less sensitive to the value \( E_i \) than the uncertainty in the composition is (compare figure 3.5).

Figure 3.10 shows the contribution of each energy separately to the uncertainty in the example given above. The fraction of the uncertainty that originates from \( E_i \) is plotted as a function of the lower energy. As for the fractions, the main contribution to the uncertainty originates from \( E_2 \). The uncertainty at \( E_1 \) is even of no influence at all if just fluid density is to be measured. This also could have been derived from equation 3.8: for high \( \gamma \)-energies, the product of electron density and mass absorption coefficient of oil is almost equal to that of water (see section 3.2.2). \( \Delta M_i \) is thus multiplied by a comparatively small factor.
Figure 3.11: Influence of a salinity change of 150 kg m$^{-3}$ to 200 kg m$^{-3}$ on the composition triangle. $E_1=30$ keV, $E_2=300$ keV. Further data can be found in section 3.3.1.
3.4 Differences between actual and calibration circumstances

3.4.1 Introduction

The three calibration measurements make up the triangle from which the fractions are determined. For reasons that will be discussed below these calibrations may not hold for the actual situation. Sometimes there is no possibility to determine the new triangle and errors are made. Three types of errors can be distinguished.

1. A change in (one of) the vacuum count rates: this causes a shift of the whole triangle. The absolute errors in the fractions are thus independent of composition.

2. A change in the length of the fluid path: this causes the triangle to stretch along the two axes without change of shape (see section 3.2.1). The error is small for high gas fractions as this point hardly shifts. The error is at most on the oil-water line.

3. A change in the properties of (one of) the phases: a change of e.g. the salinity of the water causes a shift of just the water calibration point. Figure 3.11 shows the influence of a change of salinity from 150 to 200 kg m\(^{-3}\) on the triangle using the data from section 3.3.1 and an energy combination of 30 and 300 keV. This figure shows that:

* the absolute errors in the fractions are zero for 0% water and maximal for 100% water;
* the absolute errors increase linearly with the water fraction, independent of the water-gas ratio.

Similar reasonings hold for changes of oil and gas properties.

It is also possible to give an analytical expression for the error in the fractions caused by a difference between the actual and the calibration circumstances. Equation 2.10 can be written in the form:

\[
\hat{\Delta} = \mathbf{m}
\]  

(3.12)

with \(\hat{\Delta}\) - calibration matrix; 
\(\mathbf{a}\) - fraction vector given by \(\mathbf{a}=(a_1,a_2,a_3)\); 
\(\mathbf{m}\) - measuring vector given by \(\mathbf{m}=(M_1,M_2,1)\).

The error in \(\mathbf{a}\), \(\Delta \mathbf{a}\) due to an error in \(\hat{\Delta}\) of \(\Delta \hat{\Delta}\) then is, neglecting second order terms (Strang, 1980):

\[
\Delta \mathbf{a} = \hat{\Delta}^{-1} \Delta \hat{\Delta}\mathbf{a}.
\]  

(3.13)

The sections below discuss the magnitude of the different errors and give where possible indications for corrections.
3.4.2 Temperature and pressure

Line temperature and pressure are not constant and may differ appreciably from the calibration temperature and pressure. The influence on the composition measurement is that the actual oil, water and gas densities differ from the calibration densities.

Temperature variations mainly influence the position of the oil and water calibration. The oil density changes relatively most as a function of temperature. The order of magnitude of the errors is illustrated by the following example: 100% oil (worst case) with a calibration temperature of 20°C and an actual temperature of 50°C results in 97.3% oil and 2.7% gas.

Pressure variations mainly influence the gas calibration. The order of magnitude of the errors is illustrated by the following example: 100% gas (worst case) with an actual pressure that is 10 bar higher than the calibration pressure results in 99.2% gas and 0.8% oil.

An exact correction for a change in oil density follows from equation 2.7:

$$\ln(R_{oa}(E_{i})) = (1 - \frac{\rho_{oa}}{\rho_{o}}) \ln(R_{v}(E_{i})) + \frac{\rho_{oa}}{\rho_{o}} \ln(R_{o}(E_{i}))$$

(3.14)

with $R_{oa}(E_{i})$ - actual calibration count rate at $\gamma$-energy $i$ [s$^{-1}$].

Similar equations hold for water and gas. The vacuum count rates are usually not known. They can however be calculated using the fact that oil and gas have approximately equal mass absorption coefficients (see section 3.2.2). A good approximation for the vacuum count rates then follows from equation 2.7:

$$\ln(R_{v}(E_{i})) = \ln(R_{g}(E_{i})) + [\ln(R_{g}(E_{i})) - \ln(R_{o}(E_{i}))] \frac{\rho_{g}}{\rho_{o} - \rho_{g}}$$

(3.15)

Temperature variations of 50°C and pressure variations of 10 bar then cause errors that are smaller than 0.1%.

The errors resulting from a difference between the actual and calibration temperature or pressure can thus easily be avoided by correcting the calibration points for the actual temperature and pressure.
Figure 3.12: Absolute errors in the fractions caused by a salinity change. $E_1=30$ keV, $E_2=300$ keV, $\Delta C=10$ kg m$^{-3}$, $\alpha_s=100\%$. For a different salinity change (or $\alpha_s$) the scaling of the y-axis should be multiplied by the quotient of the new and the old salinity change (or $\alpha_s$).
3.4.3 Salinity

Salt, mainly Chlorine, is, compared to the other elements in water, a strong absorber. Section 3.3.2 showed that this has the advantage of an increased precision. Disadvantage is that salinity changes cause large errors. Possible cause of salinity changes is that the salt content of the injected water differs from the formation water. Time scales of salinity changes are expected to be large (months) so continuous monitoring will not be necessary. The time scales are probably not large enough to allow new calibrations, especially sub-sea.

The error is, using equation 3.13:

\[ \Delta \varepsilon = a_w \Delta C \cdot A^{-1} \frac{\partial W}{\partial C} \]  

(3.16)

with \( C \) - salinity in kg [Na Cl equivalents] \( m^{-3} \);
\( \Delta C \) - salinity change in kg \( m^{-3} \);
\( W \) - water calibration vector given by \( W^T = (W_1, W_2, 0) \).

This equation shows that the magnitude of the error depends on the \( \gamma \)-energies. It can however be shown that the dependency is only weak.

Figure 3.12 shows the magnitude of the absolute errors. The absolute errors in the fractions are plotted as a function of salinity, for the 100% water point (worst case), with \( \Delta C = 10 \) kg \( m^{-3} \), an energy combination of 30 and 300 keV and the data from section 3.3.1 (except for salinity). For other values of \( \Delta C \) (or \( a_w \)) the scaling on the \( y \)-axis can be multiplied by the quotient of the new and the old \( \Delta C \) (or \( a_w \)).

There are little data available on the order of magnitude of the salinity changes (not interesting for operators). The figure however shows that small changes cause large errors in the fractions. This is independent of the length of the fluid path and hardly dependent on the energy combination. A correction is therefore desired.

The water calibration is, rewriting equation 2.7:

\[ W_i = \ln (R_v (E_i)) - \left[ \frac{\mu}{\rho} \right]_{\text{salt}} C - \left[ \frac{\mu}{\rho} \right]_{\text{H_2O}} (\rho_w C) . \]  

(3.17)

An (approximate) formula for the water density from the Shell handbook (1992) can be written as:

\[ \rho_w = f(T, p) + Cg(T, p) \]  

(3.18)

with \( f(T, p), g(T, p) \) - functions of temperature and pressure.
For a different salinity, the water calibration is:

\[ \bar{W}_{ia} = \bar{W}_i + \frac{\partial \bar{W}_i}{\partial C} \Delta C \]  

(3.19)

with \( \bar{W}_{ia} \) = actual water calibration [\( \ln(\text{counts s}^{-1}) \)].

To find the actual water calibration it is thus necessary to determine the actual salinity or the salinity change.

One possibility is to use a third \( \gamma \)-energy. The functions of the three energies are \( (E_1 < E_2 < E_3) \) (compare section 3.2.4):

* \( E_1 \): measuring Oxygen concentration;
* \( E_2 \): measuring Chlorine concentration;
* \( E_3 \): measuring electron density.

The best way to write the equation is:

\[
\begin{bmatrix}
O_1 \bar{W}_1 + \frac{\partial \bar{W}_1}{\partial C} \Delta C & G_1 \\
O_2 \bar{W}_2 + \frac{\partial \bar{W}_2}{\partial C} \Delta C & G_2 \\
O_3 \bar{W}_3 + \frac{\partial \bar{W}_3}{\partial C} \Delta C & G_3 \\
1 & 1 & 1
\end{bmatrix}

\begin{bmatrix}
\alpha_o \\
\alpha_w \\
\alpha_g
\end{bmatrix}

= \begin{bmatrix} M_1 \\ M_2 \\ M_3 \\ 1 \end{bmatrix},
\]

(3.20)

No articles have been published on this subject. The reason is probably that the system is very ill-configured so small errors in the measured count rates result in huge errors in the composition. It is however recommended to do more calculations on it just because so little is known of this subject.

No other techniques for the on-line determination of salinity were encountered. Salinity changes are thus a major problem in determining the volume fractions accurately.
3.4.4 Miscellaneous

Below, a short comment is given on the remaining differences between the calibration and the actual situation that may occur. They are however not expected to cause large errors.

Length of the fluid path

The length of the fluid path is not likely to change much. To indicate the order of magnitude: a 1% change of $t_f$ causes with 100% liquid approximately a 1% shift between the liquid and gas fraction without change of water cut.

Wall thickness

The influence of a change in wall thickness depends on its composition. Different types of wall material are discussed in section 3.8.2. In case of RCFE (Reinforced Carbon Fibre Epoxy, see section 3.8.2) a change of 0.2 mm ($2\times0.1\text{ mm}$) with $t_f=5 \text{ cm}$ causes a shift between oil and gas of 1%. Changes of this magnitude are not likely to occur and with RCFE the errors will be small. The errors may be appreciably larger with different wall materials (stronger absorbers), especially if $t_f$ is small.

Deposition of wax

Deposition of wax in a vertical pipe, especially in the throat of the venturi where the velocities are high, is not expected to occur.

Oil

Differences in oil composition of one formation are not likely to occur. Wells that produce $\text{H}_2\text{S}$ may cause problems because of the relatively high atomic number of S. These wells are however scarce.

Gas

The different types of gas mainly differ in density, i.e. in mean atomic mass. The error is the largest at high pressures. To indicate the order of magnitude: a calibration mean atomic mass of 40 u and an actual mean atomic mass of 50 u causes at 100 bar and 30% GVF a shift between oil and water of 1%. The errors are thus small.
Figure 3.13: Illustration of non-logarithmic averaging.
A - non-logarithmic averaging in time;
B - non-logarithmic averaging in place.
3.5 Influence of non-logarithmic averaging

3.5.1 Introduction

Section 3.3 showed that the longer the counting time, the larger the precision of the fractions. There is however at least one problem attached to long counting times: the composition along the path of the beam may change or vary during the counting time $\tau$ (see for an example figure 3.13 A). The determination of the three mass flow rates then requires the mean composition during $\tau$, so the mean logarithms of the count rates. The measurement however results in the different logarithms of the mean count rates. The resulting composition will thus not represent the mean composition. This phenomenon will be denoted with non-logarithmic averaging in time. Note that the above also holds for the situation that the composition along the path of the $\gamma$-photons is "frozen" during $\tau$ but that the composition is not equally distributed over the detector area (see for an example 3.13 B). This will be denoted with non-logarithmic averaging in place.

The two examples from figure 3.13 result in the same errors: the measured logarithm of the count rate at each of the $\gamma$-energies is $\ln((1-\lambda)a+\lambda b)$, where $a$ is the count rate in the first part of $\tau$ (or the left most part of the detector area) and $b$ the count rate in the other part. The mean logarithm of the count rate, necessary for the composition determination, is however $(1-\lambda)\ln(a)+\lambda\ln(b)$. One property of the logarithm is that $\ln((1-\lambda)a+\lambda b)$ is not equal to $(1-\lambda)\ln(a)+\lambda\ln(b)$ if $a\neq b$ and $0<\lambda<1$.

One possible cause of composition changes during $\tau$ is that the mean composition is constant but that the instantaneous fractions vary around that mean. Examples are "constant" slug flow with several slugs in one measurement and "constant" bubble flow. A model for the magnitude and distribution of the variations then allows corrections. Other composition changes cause errors.

Some properties of the difference between the measured logarithm of the count rate and the mean logarithm of the count rate are as follows.

1. The measured logarithm of the count rate is higher than the mean logarithm of the count rate.

The reason is that for concave functions, i.e. functions with a negative second derivative, holds:

$$ f((1-\lambda)x_1+\lambda x_2)>(1-\lambda)f(x_1)+\lambda f(x_2) \quad x_1<x_2, \quad 0<\lambda<1 \quad (\text{Almering et al., 1989}). $$

The second derivative of the logarithm is $-1/x^2$ thus negative.

2. The absolute difference between the mean and the measured logarithm of the count rate is large for $E_1$ and small for $E_2$.

This will be shown using the example illustrated in figure 3.13: the absolute error caused by averaging two count rates
Figure 3.14: Absolute error in the oil fraction caused by non-logarithmic averaging.
The absolute error is plotted for the situation that the gas fraction is half the counting time (or half the detector area) 5% higher and the other half 5% lower than the mean gas fraction. The water cut is constant. For a different variation the scaling of the y-axis can be multiplied by the quotient of the new and the old variation. $t_e=5$ cm, further data can be found in section 3.3.1.
instead of their logarithm only depends on their quotient for:

\[ \ln((1-\lambda)a+\lambda b)-[(1-\lambda)\ln(a)+\lambda\ln(b)]=\ln\left(\frac{b}{a}\right)^{-\lambda}(1-\lambda+\lambda\frac{b}{a}) \]  \hspace{1cm} (3.21) \]

with \( a, b \) - arbitrary positive numbers.

The more \( a/b \) differs from 1, the larger the difference. The resulting absolute differences at \( E_1 \) are thus larger than at \( E_2 \) because of the increase of the linear absorption coefficients with decreasing \( \gamma \)-energy. For the composition determination the absolute difference should be compared to the total range of possible values, e.g. the difference between the water and gas calibration. It can be shown that the difference at \( E_2 \), in spite of its smaller range, usually is negligible.

3. The differences between the mean and the measured logarithms of the count rates at \( E_1 \) and \( E_2 \) result in an over-reading of the oil fraction, mainly at the expense of the water fraction, i.e. a too low water cut with an approximately correct gas fraction.

This follows combining 1 and 2 with the composition triangle (see figure 3.1): the measured point is to the right hand side, slightly higher than the actual point, representing a shift from water to oil, almost parallel to the lines of constant gas fraction.

Figure 3.14 illustrates the order of magnitude of the errors. The gas fraction is half the counting time (or for half of the detector area) 5% higher and for the other half 5% lower than the mean gas fraction (the absolute gas fraction is of no influence as can be derived from equation 3.21. The error in the oil fraction (slightly larger than the error in the water fraction as the error in the gas fraction is slightly negative) is plotted as a function of \( E_2 \) for a water cut of 0 and 100%. The water cut is kept constant and further data are taken from section 3.3.1. For a different variation the scale can (approximately) be multiplied by the quotient of the new and the old variation. For a different water cut the error is approximately a linear combination of the 0 and 100% WC lines.

The figure shows that the errors are very large. The error increases for higher values of \( E_2 \) especially with low salinities and low \( E_2 \). The influence of fluid path (not shown) is negligible.
Figure 3.15: Estimated absolute variation of the gas fraction in bubble flow. The length of the fluid path $t_e$ equals 5 cm. For a different $t_e$, the scaling of the y-axis should be multiplied by the square root of the quotient of the old and the new $t_e$. 
3.5.2 Non-logarithmic averaging in bubble flow

In bubble flow there are two time scales, the time scale for changes in the mean composition \( t_c \) and the time scale for variations around that mean \( t_v \). The measuring time will be between those two, i.e. \( t_v < t < t_c \). The order of magnitude of the composition changes during the measuring time is therefore determined by variations on time scale \( t_v \). Below, a simple model will be given for these composition variations.

The following assumptions are made:
* bubbles are cubic with edge \( d \);
* the composition along the path of the beam at a particular point in time is a random sample of \( d/t_f \) cubes of a binomial distribution with chance \( \alpha_g \) at gas and \((1-\alpha_g)\) at liquid.

If the measuring time is long, many samples will pass and a measure for the variation in the gas fraction is the standard deviation of the binomial distribution:

\[
\sigma_g = \sqrt{\frac{\alpha_g(1-\alpha_g)}{t_f}} \frac{d}{t_f} \tag{3.22}
\]

with \( \sigma_g \) - approximation of the standard deviation in the gas fraction;
\( d \) - diameter of the bubbles.

Figure 3.15 shows the variations with a mean gas fraction of 10, 20 and 30% and a 5 cm fluid path. The variations are independent of the area of the detector.

The design bubble diameter for the ILS is comparatively small: 0.5 mm. The worst case situation is WC=100%, GVF=30%. This model predicts that with \( t_v \) equals 5 cm, the DEGRA measures 5% oil and 65% water in stead of 70% water.

The mean bubble diameter in bubbly flow is usually several millimetres. Combining figure 3.14 and 3.15 it follows that large errors will be made, especially for small pipe diameters.

In two-phase flow this phenomenon might be used for the determination of mean bubble size: two (or more) different (well chosen!) \( \gamma \)-energies respond differently to the variations in void fraction during one measurement. The parameters are the bubble size distribution parameters. No literature is available on this subject as non-logarithmic averaging due to bubbles is not acknowledged at all. It is recommended to investigate whether this is a rewarding technique.
Figure 3.16: Absolute error in the composition due to the bias in the estimate of the logarithm of the count rate.

The absolute systematic error in oil, water and gas fraction due to the bias in the estimate of the logarithm of the count rate originating from $E_1 \left(R_i(E_i)\tau=500, R_i(E_i)\tau=\infty\right)$ and from $E_2 \left(R_i(E_i)\tau=\infty, R_i(E_i)\tau=500\right)$ is plotted as a function of $E_1$. $E_2=300$ keV, $t_s=5$ cm, salinity = 150 kg m$^{-3}$. Further data can be found in section 3.3.1.
3.5.3 Slug flow; limitations to the counting time

The flow pattern changes for higher gas volume fractions from bubble to slug flow. The magnitude of the variation then increases. Errors due to non-logarithmic averaging, if the measuring time is of the same order of magnitude as the characteristic time of a slug, are therefore large.

One solution is to decrease the measuring time resulting in many measurements within a slug. The uncertainty in each measurement is large but the systematic error will be small. There is however a limit: the expected value of the logarithm of a Poisson distributed parameter is not equal to the logarithm of the expected value of the parameter (or $E(\ln(x)) \neq \ln(E(x))$ where $x$ is the Poisson distributed parameter and $E(\cdot)$ the expected value). The bias is given by:

$$E(\ln(x) - \ln(\mu)) = \frac{1}{2\mu^2} + \frac{1}{3\mu^3} + \frac{1}{4\mu^4} + \ldots = \frac{1}{2\mu} + O(\mu^{-2})$$

(3.23)

with $\mu = E(x)$.

The resulting error in the logarithm of the count rate is thus an order of magnitude smaller than the statistical uncertainty.

Figure 3.16 illustrates the influence on the measured fractions using the data from section 3.3.1 (except for $\eta(E_{1,2})$ and $I_1(E_{1,2})r$) and with $E_2=300$ keV. The systematic error in the fractions with $R_1(E_1)r=500$, $R_1(E_2)r=\infty$ and $R_1(E_1)r=\infty$, $R_1(E_2)r=500$ respectively, representing the systematic errors due to just $E_1$ or just $E_2$ respectively, is plotted as a function of $E_1$ for 100% water, the point with the largest error. To obtain the errors for a different $R_1(E_{1,2})r$, the scale can be multiplied by the quotient of the new and the old $R_1(E_{1,2})r$.

A few remarks should be made.
* Below 25 keV the mean number of counts measured at $E_1$ is less than 10 if $R_1(E_1)r=500$. Then higher order terms in equation 3.23 become important.
* The value of $E_2$ is of little importance.
* The errors at each energy separately partly compensate if they are added.

From the above discussion, criteria for a minimal counting time can be derived:
1. the mean number of counts expected to be measured at $E_{1,2}$ should be larger than 10;
2. the absolute, systematic error (of $E_1$ and $E_2$ together) in the worst point (in slug flow 100% liquid with the maximal water cut) should be below some 1-2%.

The limit is usually chosen larger, e.g. because background has to be subtracted. With a not too weak source and not too slow equipment however measuring times of the order of milliseconds can be achieved resulting in many measurements
within a slug. The interpretation of these data is however difficult.

A different solution, proposed by K. G. Rafa (1989) is to use a long (i.e. long compared to the characteristic slug time) measuring time and a slug correction factor, obtained from a slug model. This method increases the number of uncertainties in the measuring system while, without large expenses, the measuring time can be decreased. This is therefore not considered rewarding.

From a statistical point of view the measuring times can be chosen very short. In slug flow it is better to use the short measuring times to reduce the systematic error than using long measuring times and some (semi-)empirical correction.

For completeness it should be stated that the standard deviation of the sum of N measurements of x seconds has apart from higher order terms the same standard deviation as 1 measurement of N*x seconds, provided that the expected value of each of the N measurements is larger than 15.
Figure 3.17: Absolute difference between gas fraction along the path of the beam and the mean GVF. The difference is plotted as a function of the ratio of the GVF in the middle of the pipe to the GVF at the wall of the pipe for different profile exponents and 10% mean GVF. For other mean gas volume fractions, the scaling on the y axis can be multiplied by the quotient of the new and the old one.
3.6 Concentration profile of the gas phase

The DEGRA technique measures the composition along the path of the beam. These fractions do not represent the volume fractions if the phases are not equally distributed. The mean concentration profiles in vertically upward bubble flow are axisymmetric and the concentration profiles of oil and water will be approximately the same.

An approximate formula for the void fraction profile in a vertically upward bubble flow line is given by (Govier and Aziz, 1967):

\[
\frac{\varepsilon_g - \varepsilon_{aw}}{\varepsilon_{g0} - \varepsilon_{aw}} = \left(\frac{r}{R}\right)^n
\]

(3.24)

with \((r/R)\) - relative distance from the centre [-];
\(\varepsilon_g\) - void fraction at relative distance \((r/R)\) [-];
\(\varepsilon_{aw,0}\) - \(\varepsilon_g\) at the wall, centre line [-];
n - profile exponent [-].

Integration yields that the difference between the gas volume fraction and the gas fraction along the path of the beam through the centre of the tube is given by:

\[
\Delta \varepsilon_g = (\varepsilon_{g0} - \varepsilon_{aw}) \left(\frac{2}{n+2} - \frac{1}{n+1}\right) = \alpha_g \left(\frac{n}{n+1}\right) \left(\frac{1-q}{n+2q}\right)
\]

(3.25)

with \(q = \varepsilon_{aw}/\varepsilon_{g0}\) [-].

Figure 3.17 shows the differences for several values of \(n\) and \(q\) and 10% GVF. For different gas volume fractions the scaling on the y-axis can be multiplied by the quotient of the old and the new GVF. It should be stressed that this is the difference between gas fraction along the path of the beam and the GVF, not the homogeneous composition.

The error in the ILS, where the flow conditions are very unstable (boiling oil, close bends, etc.), has to follow from measurements. The figure however shows that the errors may be large, requiring corrections.

This error will greatly reduce if an annular configuration is used with the source in the middle instead of the usual circular configuration (see figure 3.18 on page 72). This however considerably increases the complexity of the construction.
3.7 Measuring errors

The detector should register the photons originating from the source, having exactly energy $E_1$ or $E_2$. Due to detector noise, electronical noise, background radiation, etc. also pulses are registered corresponding to energies close to $E_1$ and $E_2$. The intensity of these pulses however may depend appreciably differently on the composition than the real $E_1$ and $E_2$. This, combined with the finite energy resolution, i.e. the ability to differentiate between two peaks that are close together in energy, causes non linearities in the equations from which the composition is determined and thus errors in the fractions.

The error depends on detector, source, intensities, collimation, etc. A general discussion is therefore not rewarding. Chapter 5 however describes experiments that show magnitude and influence of this error for several detectors.
Figure 3.18: Construction of the DEGRA.  
A - circular; B - annular.
3.8 Application of the DEGRA technique

3.8.1 Introduction

The five sources of error in the measurement of the volume fractions of oil, water and gas using the DEGRA technique are:

1. statistical uncertainty (see section 3.3);
2. calibration errors (see section 3.4);
3. non-logarithmic averaging (see section 3.5);
4. concentration profile (see section 3.6);
5. measuring errors (see section 3.7).

Changes in salinity is the only calibration error that is expected to cause problems. The magnitude of the error is independent of the configuration, i.e. γ-energies, length of the fluid path, wall material, detector, construction, etc.

Non-logarithmic averaging causes large errors in the water cut determination, even in bubble flow. The error depends on the length of the fluid path and slightly on $E_a$.

A concentration profile usually causes an over reading of the gas fraction. The error is dependent on the construction, i.e. (see figure 3.18) circular or annular. The error is independent of the remaining configuration (γ-energies, wall material, detector, etc.).

Measuring errors should be made negligible.

The statistical uncertainty is the only error that is greatly influenced by the choice of the γ-energies, strength of the γ-energies, wall material and detector.

The above considerations, combined with the demands of the environment where the instrument is aimed for determine the configuration. The following aspects have to be chosen:

1. wall material;
2. detector;
3. source(s);
4. construction (annular, circular).

Below it is assumed that the construction (length of the fluid path) is known. This is not trivial as especially for large diameters it may be more accurate to use an annular configuration. A separate project is however necessary to determine criteria for a transition from circular to annular and for the exact measures.

The criteria to chose the remaining facets are:
* statistical uncertainty;
* safety and environmental considerations.
Figure 3.19: Measured mass absorption coefficient of RCFE, compared to the mass absorption coefficient of Carbon.
3.8.2 Wall material

The requirements to the wall material are:
* transparent for γ-radiation (see section 3.3.2);
* strong, non-toxic, etc.

For an extensive list of materials reference is made to the report by Kolar (1991). Reinforced Carbon Fibre-Epoxy (RCFE), manufactured by TNO (Delft, The Netherlands) is the best solution as it combines relative transparency with an extreme strength.

RCFE contains 60 wt% carbon fibre and an epoxy, of which no information is available, probably consisting of H, C and O. Absorption tests at KSEPL show that the mass absorption coefficient can be approximated with the mass absorption coefficient of Carbon (see figure 3.19). The density equals 1420 kg m\(^{-3}\) and the tensile strength is 2000 to 3000 MPa (compare steel: 450 MPa).

Beryllium is the best alternative but this is toxic. Other alternatives are technical ceramics or other fibres than carbon fibre that are combined with resins into a composite. Steel and Aluminium are unsuitable as window material because they combine relative weakness with a relatively strong absorption.
3.8.3 Detector

The requirements to the detection system are as follows.
* The total efficiency of the detection system should be high, in order to reduce source strength and shielding.

The derivation in chapter 2 of the equation that allows to calculate the composition from the absorption of two different γ-energies, assumed a narrow parallel beam. In reality a radio active source sends radiation in all directions. The total efficiency is defined as the mean number of photons of energy $E$ registered divided by the mean number emitted. The total efficiency is, in absence of absorbing material, a factor, the geometry factor, times the detector efficiency. The quotient of the geometry factors of two detectors is (approximately) the quotient of the two areas (notice that in practice due to non-logarithmic averaging differences in the length of the fluid path are not allowed so the area is restricted).
* The energy resolution should be sufficiently high (depending on the source).
* The detector should be able to handle high count rates.
* For field applications the detector should be rugged and need (preferably) no High Voltages (HV).

The following systems are available.
1. Proportional counter (+ pre-amplifier, amplifier, ADC).
   The Proportional counter is a gas filled detector. It needs a HV (3-5 kV), is (although the manufacturer claims differently, Reuter-Stokes, 1987) not sufficiently rugged and it can not handle count rates over 50,000 cps. Advantages are the high total efficiency (area large and detector efficiency high up to 100 keV) and the energy resolution.

2. Scintillation detector (+photo multiplier, amplifier, ADC or + photo-diode, pre-amplifier, amplifier, ADC).
   A scintillation detector with a photo multiplier is preferably not used in the field because the photo multiplier needs high voltage (3-5 kV). Ruggedness is not a problem because scintillation crystals exist that are shock resistant non-hygroscopic. Another draw back is the not too good energy resolution. Advantages are its high(est) total efficiency and its capability of handling high count rates (depending on the crystal chosen). A scintillation detector with photo diode can not handle high count rates (>50,000 cps) or low γ-energies (<50keV) and it has a bad energy resolution. It does meet the safety and ruggedness requirements for field use. Further information on scintillation detectors can be found in the brochures of Harshaw/QS.

3. Semiconductor detector (+ pre-amplifier, amplifier, ADC).
   The High Purity Germanium detector is the ideal solution for laboratory measurements (count rates >1 Mcps, resolution <0.5 keV, total efficiency high for not too high γ-energies). The High Purity Germanium detector however has to be cooled to liquid nitrogen temperature (-195°C).

Lithium Drifted Silicon, Si(Li) is a semiconductor detector
Figure 3.20: Detector efficiency of Si detectors (Canberra).
that hardly needs cooling (to about 5°C) and that does meet
the safety and ruggedness requirements. Draw-backs are the low
total efficiency caused by the low atomic number (14) of Si
(see figure 3.20) and the decrease of resolution when the
volume increases: the highest resolution is about 2.3 keV Full
Width Half Maximum (FWHM) for 0.5*12 mm², for 0.5*100 mm² the
resolution is decreased to about 12 keV FWHM. Further
information can be found in the brochures of Canberra.

A recent review of other semiconductor detectors is given by
Cuzin (1987). Most interesting are CdTe and HgI₂, that are
commercially available (EuroRad, via Intechmij BV, Diemen, The
Netherlands). They have a high efficiency, because of their
high atomic numbers, 48-52 and 80-53 respectively and allow
high operating temperatures, up to 30 and 50 °C respectively.
CdTe is a rugged crystal, HgI₂ less (has to be encapsulated
from air). Research is necessary to find out the influence of
some characteristic (unwanted!) spectral properties on the
composition measurement.

The only detector that is able to meet safety and resolution
requirements is Si(Li). Draw back is the low (total)
efficiency. Future alternatives may be CdTe and HgI₂. They have
however some spectral properties that cause non linealities.
Experiments are necessary to determine the magnitude of the
errors because only not too large non linealities cause
tolerable errors in the fractions.

Further information on detectors can be found in the book by
3.8.4 Source

The statistical error determines the choice of the two \( \gamma \)-energies. Figure 3.5, 3.7, 3.8 and 3.10 show that for \( E_i \) energies are sought between 15 and 45 keV. In addition, there are several practical aspects:

* half life not too long (environment) or too short (requiring replacement);
* (preferably) both energies emitted by one source;
* not too many unused \( \gamma \)-energies (requiring detector time);
* no strong high \( \gamma \)-energies (shielding);
* peaks sufficiently isolated in view of the detector resolution.

Table 3.2 summarises the available low energy sources, leaving out small (<100 days) and large (>1000 years) half-lives.

**Table 3.2: Summary of the emission lines of actual sources.**

<table>
<thead>
<tr>
<th>Source</th>
<th>Energy</th>
<th>Emission rate</th>
<th>Half life</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>keV</td>
<td>per 100 decays</td>
<td>days</td>
</tr>
<tr>
<td>( ^{109} )Cd</td>
<td>22.1</td>
<td>82.1</td>
<td></td>
</tr>
<tr>
<td></td>
<td>25.3</td>
<td>17.4</td>
<td>453 days</td>
</tr>
<tr>
<td></td>
<td>88</td>
<td>3.8</td>
<td></td>
</tr>
<tr>
<td>( ^{133} )Ba</td>
<td>30.8</td>
<td>100</td>
<td>10.74 years</td>
</tr>
<tr>
<td></td>
<td>35.4</td>
<td>23</td>
<td></td>
</tr>
<tr>
<td></td>
<td>81</td>
<td>35.5</td>
<td></td>
</tr>
<tr>
<td></td>
<td>356</td>
<td>61</td>
<td></td>
</tr>
<tr>
<td>( ^{153} )Gd</td>
<td>41</td>
<td>87</td>
<td>241.5 days</td>
</tr>
<tr>
<td></td>
<td>45.3</td>
<td>22</td>
<td></td>
</tr>
<tr>
<td></td>
<td>97.4</td>
<td>17</td>
<td></td>
</tr>
<tr>
<td></td>
<td>103.2</td>
<td>28</td>
<td></td>
</tr>
<tr>
<td>( ^{241} )Am</td>
<td>13.9</td>
<td>13.5</td>
<td></td>
</tr>
<tr>
<td></td>
<td>17.8</td>
<td>18.4</td>
<td></td>
</tr>
<tr>
<td></td>
<td>21</td>
<td>5</td>
<td>432.2 years</td>
</tr>
<tr>
<td></td>
<td>26</td>
<td>2.5</td>
<td></td>
</tr>
<tr>
<td></td>
<td>59.5</td>
<td>35.9</td>
<td></td>
</tr>
</tbody>
</table>

Two emission lines close in energy require a high detector resolution. Two emission lines very close in energy however depend almost equally on the composition and no large errors are made considering the two energies as one. A detector with a lesser resolution will then comply. Considering 14, 18 and 21 keV of \( ^{241} \)Am as one energy results in large errors. Section
5.2 will however show, theoretically and by experiments, that with 22+25 keV of $^{109}$Cd (and thus also with 31+35 keV of $^{133}$Ba and 41+45 keV of $^{152}$Gd) hardly any problems occur.

A Si detector is, because of its low efficiency (see figure 3.20), only eligible for two energy combinations:
1. $^{241}$Am: 18+60 keV with a small volume (12*0.5 mm$^3$) Si detector integrated on a large volume (100-200*0.5 mm$^3$) Si detector;
2. $^{109}$Cd+$^{152}$Gd: 23+43 keV with a large volume (100*0.5 mm$^3$) Si detector.
Tests with the latter combination are described below.

For high salinities and large pipe diameters (compare figure 3.7 and 3.8) $^{133}$Ba and $^{152}$Gd are eligible dual energy sources. The efficiency of the Si detector is however too low. Effort should be put in finding alternative detectors like CdTe or HgI$_2$. Otherwise a scintillation detector has to be used in spite of the high voltage.

It is interesting to mention that Rebgetz et al. (1991) use for the 6" fluid path the energy combination of 60 keV of $^{241}$Am and 356 keV of $^{133}$Ba. This is a very bad combination for statistical reasons (see figure 3.8) environmental reasons (two sources, long half lives) practical reasons (collimation, shielding, escape peaks). Just the $^{152}$Gd source is a much better, more convenient and responsible source.
3.9 Conclusions

* The representation of the DEGRA technique as a triangle is a convenient tool in understanding the different errors.

* The functions of the two energies in dual energy $\gamma$-ray absorption composition measurements are (see figure 3.3):
  + $E_1$: measuring O or Cl concentration;
  + $E_2$: measuring electron density.

* The main sources of error in the DEGRA composition are follows.
  + Statistical uncertainty.
  Figure 3.4 to 10 show the influence of all important variables.
  + Changes in salinity.
    Changes in salinity cause large errors in the composition, hardly dependent on the configuration. Little data are available on the magnitude of actual salinity changes.
  + Non-logarithmic averaging.
    Non-logarithmic averaging causes in bubble flow large errors in the water cut. The error is inversely proportional to the square root of the length of the fluid path. The error in the ILS is comparatively small (worst case: 70% water, 30% gas and $t_f=5$ cm results in 65% water, 5% oil and 30% gas) because of the small bubble diameter (0.5 mm).
  + Gas concentration profile.
    A gas concentration profile leads to a large (up to 40-50% relative) over reading of the gas fraction. The magnitude of the error for the ILS has to follow from measurements as the flow conditions are very unstable.

* Counting times of the order of milliseconds can be reached.
  For the study of slug flow these short counting times are considered better than long counting times combined with a correction for non-logarithmic averaging.

* Statistical and safety considerations determine the configuration if the length of the fluid path is fixed.

* Presently, in the field only Si detectors are eligible. This is a large constraint and it is necessary to investigate alternatives like CdTe or HgI$_2$.

* There are sources to cover pipe diameters of 1 to 4 inch and salinities of 0 to 300 kg m$^{-3}$.

# Further research is necessary to determine criteria for the choice of the construction (circular or annular).

# It is recommended to investigate whether in two-phase flow non-logarithmic averaging can be used to measure bubble size distribution parameters.
4 MEASUREMENT OF VELOCITIES WITH A VENTURI IN NON HOMOGENEOUS FLOW

4.1 Introduction

The advantage of the assumption of homogeneous flow is that the three phases have the same characteristic velocity. If this assumption does not hold, two or three individual velocities have to be derived from one measured parameter. This means that a unique relation between the individual velocities of the three phases has to be found.

The objective of the venturi and DEGRA in the ILS is to measure oil production. Not too large errors in the water and gas production are acceptable. The DEGRA is aimed to measure the composition of the mixture. The venturi will have to provide information on the velocities of the phases. Since in essence a venturi relates a pressure drop to the flow velocity, an expression is sought that relates the oil production to the pressure drop as accurate as possible.

Oil and water will be assumed to flow equally fast. This is not a very restrictive assumption because of the similar density of oil and water. Further, it is assumed that the liquid density is measured accurately, or equivalently, that the water cut is known. Non-logarithmic averaging causes errors in the water cut. However, the resulting error in the density is small because of the similar density of oil and water (moreover, for ever measuring oil production accurately with this principle, a correction for the errors caused by non-logarithmic averaging will have to be found).

A relation is thus sought between the pressure drop from inlet to throat of the venturi and the liquid and gas velocity. Chosen is for the constant slip model. Different approaches use the flow equations for bubbles (e.g. Lewis and Davidson, 1985). They however show too many uncertainties and are far from the unstable flow conditions in the ILS.
4.2 The constant slip model

In literature the constant slip model is presented in terms of quality (Chrisholm, 1988) and gas volume fraction (Slijkerman, 1993, to be published, limited distribution). Below, the presentation in gas volume fraction will be given as the ILS combines the venturi with a composition measurement. The derivation of W. Slijkerman will be followed and for details reference is made to his work. The start is slightly different because of the presence of a third phase.

The derivation starts with the three one-dimensional vertical steady state momentum equations, for oil given by:

$$\rho_o v_o \frac{dv_o}{dz} = -\frac{dp}{dz} - \rho_o g \frac{1}{A \alpha_o} (d_{ow} \tau_{ow} + d_{og} \tau_{og})$$ (4.1)

with $p$ - pressure in kg [m$^{-1}$ s$^{-2}$];
$v_o$ - oil velocity [m s$^{-1}$];
$A$ - cross-sectional area of the tube [m$^2$];
$d_{ow,og}$ - characteristic length scale for the interface between oil and water, gas [m];
$\tau_{ow,og}$ - interaction of oil with water, gas [kg m$^{-1}$ s$^{-2}$].

The assumption will be made that oil and water flow equally fast, i.e. $v_o = v_w = v$. This is not a very restrictive assumption as oil and water have similar densities. The fluid will thus be treated as a two-phase liquid-gas mixture. The liquid density is given by:

$$\rho_l = \frac{\alpha_o \rho_o + \alpha_w \rho_w}{\alpha_o + \alpha_w}.$$ (4.2)

The one-dimensional vertical steady state momentum balance of the mixture then can be written as:

$$\alpha_g \rho_g v_g \frac{dv_g}{dz} + (1-\alpha_g) \rho_1 \frac{dv_1}{dz} = -\frac{dp}{dz} - \left[ (1-\alpha_g) \rho_1 + \alpha_g \rho_g \right] g$$ (4.3)

with $v_{1,g}$ - velocity of the liquid, gas [m s$^{-1}$].

The following velocity ratio is introduced:

$$S = \frac{v_g}{v_1}.$$ (4.4)

It follows that:

$$\frac{dv_g}{dz} = v_1 \frac{dS}{dz} + S \frac{dv_1}{dz}.$$ (4.5)

In the constant slip model $S$ is assumed constant from inlet to throat and thus $dS/dz$ can be dropped.
Inserting the equations 4.4 and 4.5 in 4.3 yields:

\[
\frac{1}{2} \left[ (1-\alpha_g) \rho_1 + \alpha_g \rho g S^2 \right] \frac{dV_1^2}{dz} = -\frac{dp}{dz} \left[ (1-\alpha_g) \rho_1 + \alpha_g \rho g \right] g. \tag{4.6}
\]

This can not be directly integrated since \( \alpha_g \) and \( \rho g \) are functions of pressure. If the gas density is related to the pressure by a polytropic law with compression index \( n \):

\[
\rho g = \rho_{g1} \left( \frac{p}{p_1} \right)^{\frac{1}{n}} = \rho_{g1} \tilde{p}^{\frac{1}{n}} \tag{4.7}
\]

with 1 - index denoting inlet;
\( \tilde{p} \) - reduced pressure;
\( n \) - compression index;

the gas superficial velocity then will change according to:

\[
V_{sg} = V_{sg1} \tilde{p}^{-\frac{1}{n}} \tag{4.8}
\]

with \( v_{sa} \) - superficial gas velocity;

and the gas fraction will depend on \( \tilde{p} \) as:

\[
\alpha_g = \frac{V_{sg}}{V_{sg} + SV_{s1}} = \frac{V_{sg1} \tilde{p}^{-\frac{1}{n}}}{V_{sg1} \tilde{p}^{-\frac{1}{n}} + SV_{s1}}. \tag{4.9}
\]

Inserting the equations 4.7 to 4.9 in 4.6 yields:

\[
- \left[ V_{sg1} \tilde{p}^{-\frac{1}{n}} + SV_{s11} \right] p_1 \frac{dp}{dz} = \frac{1}{2} S \left[ SV_{sg1} \rho_{g1} + V_{s11} \rho_1 \right] \frac{dV_1^2}{dz} + \left[ SV_{s11} \rho_1 + V_{sg1} \rho_{g1} \right] g. \tag{4.10}
\]

This is integrated from inlet to throat resulting in:

\[
\frac{1}{2} \left[ \frac{np_1 V_{sg1}}{n-1} \right] \left[ \frac{1}{1-\tilde{p}_2^{\frac{n}{n}}} \right] + SV_{s11} P_1 \left[ 1 - \tilde{p}_2^{\frac{n}{n}} \right] = \frac{1}{2} \rho_1 V_{s11} + \rho_{g1} V_{sg1} \left[ SV_{s11} \tilde{p}_2^{\frac{n}{n}} + SV_{s11} \right] \frac{\left( V_{sg1} \tilde{p}_2^{\frac{n}{n}} + SV_{s11} \right)^2}{\beta^4} - \left( V_{s11} + SV_{s11} \right)^2 \left[ \rho_{g1} V_{sg1} + \rho_1 V_{s11} \right] g \Delta h. \tag{4.11}
\]

with 2 - index denoting throat;
\( \tilde{p}_2 \) = \( (p_2/p_1) \);
\( \beta \) = \( \sqrt{A_2/A_1} \).
From this equation, an equation for the superficial liquid velocity can be derived:

\[
\frac{V_{sl}}{a_1} = \frac{n}{n-1} \frac{\alpha_g P_1 \left(1-\frac{P_2}{P_1}\right) - \frac{1}{2} \rho_g \alpha_g P_2^2}{\alpha_1 + \alpha_g P_2^2} g \Delta h
\]

(4.12)

with \( \alpha_1 \) - liquid fraction \((-1-a_g) [-]\).

For an ideal gas under isothermal conditions \((n=1)\), the first term in the numerator should be replaced by \(-\alpha_g P_1 \ln(\frac{P_2}{P_1})\). The superficial gas velocity follows from equation 4.9:

\[
V_{sg} = \frac{\alpha_g S V_{sl} \rho_{g}}{\alpha_1} P_2^{-\frac{n}{n-1}}
\]

(4.13)

Equation 4.12 and 4.13 relate the pressure drop to the liquid and gas velocity with one fit parameter, \(S\). For \(S=1\) equation 4.12 and 4.13 represent the compressible equivalents of equation 2.12 from section 2.2. The limiting cases then are:

* gas flows single phase \((\alpha_g=1, S=1)\): the well known expression for the calculation of gas flow rate from a differential pressure is obtained (Cheremisinoff, 1988);
* gas expansion is absent \((n \rightarrow \infty, S=1)\): equation 2.12 from section 2.2 is retrieved.

The order of magnitude of the error caused by not taking into account the compressibility will be illustrated by an example with velocities and areas representative for the ILS application (see figure 6.2): \(V_{sl}=1.25 \text{ m s}^{-1}, V_{sg}=0.25 \text{ m s}^{-1}, A_1=47.5 \text{ cm}^2, A_2=15 \text{ cm}^2\) and \(S=1\). If the absolute pressure is one bar, representative for the laboratory measurements, the liquid flow rate is over estimated by 0.7% and the gas flow rate by 10% for isothermal flow (assuming an ideal gas). For these measurements correction is necessary. At 5 bar, corresponding to the field measurements, these values have reduced by about a factor 5. Correction is then not necessary and equation 4.12 and 4.13 reduce to:

\[
V_{sl} = \alpha_1 \frac{1}{\sqrt{1 - \frac{A_2}{A_1}}} \left[ \frac{2(\Delta p - [\rho_g a_1 + \rho_g a_g] g \Delta h)}{\rho_g a_1 + S^2 \rho_g a_g} \right].
\]

(4.14)

and:

\[
V_{sg} = \frac{\alpha_g S V_{sl}}{\alpha_1}.
\]

(4.15)
4.3 Discussion of the constant slip model

In literature the constant slip model is used to model slug flow (Sanchez Silva et al., 1991, Frank et al., 1980) or high quality flow (Chisholm, 1967). Therefore, below, comment will be given on the application in bubble flow.

The constant slip model in bubble flow mainly influences the gas velocity. The reason is that the additional pressure drop caused by the higher gas velocity is very small: the only difference between $4.14$ and $2.12$ is the term $S^2 \rho \alpha_g$ in stead of $\rho \alpha_g$ in the denominator, the influence is small because of the small gas density and the low gas volume fractions. The influence of $S$ on the measured liquid velocity is therefore small. The gas production however is, compared to the homogeneous gas production, approximately a factor $S$ higher. Bubble flow models predict a $S$ of around $2$ (Govier and Aziz, 1972; Wallis, 1969; Zubar and Findlay, 1965).

The main problem of the constant slip model is its one-dimensionality. The mean fractions in actual situations are not known because of the concentration profile of the gas phase. Even if the mean volume fractions over the whole cross-section of the pipe are known, still errors are made because of the combination of velocity and concentration profiles.

One solution is to apply a correction to the measured gas fraction to obtain an "effective" gas volume fraction. This procedure seems rather rough but it should be mentioned that the measured liquid velocity is not very sensitive to errors in the gas volume fraction. With some approximations it follows from equation $4.12$ that $v_{g1} \alpha (1-\alpha_g) (\Delta p/\rho)^{1/2}$. An error in the liquid velocity due to an error in the gas fraction is approximately given by:

$$\frac{\Delta v_{g1}}{v_{g1}} = \frac{1}{2} \frac{\Delta \alpha_g}{1-\alpha_g}$$

(4.16)

A correction that estimates the "effective" gas volume fraction with absolute errors within $3-4\%$ causes relative errors in the liquid flow rate that are within $2\%$ and these are acceptable. In spite of the unstable flow conditions and the differences between the properties of oil and water it should be possible to find a sufficiently accurate correction.

The errors in the gas velocity will be appreciably larger because $S$ will be highly dependent on flow conditions and fluid properties.

The influence of the assumption of constant $S$ on the measuring results becomes invisible by introducing an effective gas fraction. This can be overcome by extending the constant slip model to a second dimension. Then, equations like the ones in section 3.6 are used for the concentration profile and the assumption of constant slip changes to the assumption of a
constant slip profile (experiments by Thang and Davis (1979) show that this is approximately true). The equations then have to be solved numerically. In the ILS application this is of little value because of the unstable flow conditions. In well-established two-phase bubble flow it is probably better to use the more advanced models for the two-phase momentum equations (Drew, 1983; Ellul and Issa, 1989).

Correcting for friction and velocity distribution is difficult. The solution used for the velocity measurements described in chapter 6 is a constant discharge coefficient (compare equation 2.12) derived from single-phase calibrations, even though it is very artificial.

Equation 4.12 with a discharge coefficient and an effective gas fraction should give liquid flow rates with relative errors within a few percent provided the friction influences are small. The error in the gas flow rate will be larger. For the ILS this is not a major problem.
4.4 Conclusions

* The liquid flow rate can be calculated with a relative accuracy of a few percent from the pressure drop across the venturi and the DEGRA composition measurements, using equation 4.12 with:
  + a discharge coefficient that follows from single phase calibrations;
  + $\alpha_g$, derived from the DEGRA gas volume fraction after an empirical correction that follows from calibrations.

* The gas flow rate is calculated from equation 4.13 with:
  + the same discharge coefficient and $\alpha_g$ as for the liquid velocity calculation;
  + an $S$ that follows from calibrations.
The error in the gas flow rate will be appreciable, for the ILS application this is however not a major problem.
5 COMBINED SOURCE OF $^{109}$Cd AND $^{153}$Gd

5.1 Introduction

The available detectors strongly limit application of the DEGRA technique. Presently only Si semiconductor detectors can fulfil both resolution and safety requirements. Because the efficiency of Si detectors quickly decreases with increasing $\gamma$-energy, only two energy combinations seem to be profitable (see section 3.8): $^{241}$Am (18 + 60 keV) and $^{109}$Cd-$^{153}$Gd (22 + 41 keV). The first has proved to be a suitable source. $^{109}$Cd-$^{153}$Gd, proposed by Kolar (1991), is a new combination and has several advantages over $^{241}$Am.

1. 22 + 41 keV is eligible for higher salinities or larger pipe diameters than 18 + 60 keV (see figure 3.4 to 3.10).

2. $^{109}$Cd-$^{153}$Gd requires less detector resolution than $^{241}$Am, as discrimination is required between 22 and 41 keV instead of 14, 18 and 21 keV. $^{109}$Cd-$^{153}$Gd thus allows a Si detector with a larger volume.

3. The half lives of $^{109}$Cd and $^{153}$Gd are $1\frac{1}{2}$ and $\frac{3}{4}$ years respectively. This is much more responsible than the 430 years of $^{241}$Am.

For these reasons theoretical and experimental work has been done to test the eligibility of the combined $^{109}$Cd-$^{153}$Gd source for composition measurements. The objectives were as follows.

1. Investigate the necessity of applying filtering techniques. To obtain isolated peaks at 22 and 41 keV filtering techniques should be applied. Draw-back of these techniques is that the intensity of the required 22 and 41 keV decreases.

2. Determine the accuracy of $^{109}$Cd-$^{153}$Gd in combination with a large volume ($100\times0.5$ mm$^3$) Si detector. From preliminary experiments followed that the resolution of this detector should be just high enough to discriminate sufficiently between 22 and 41 keV.
5.2 Characteristics of \(^{109}\text{Cd}\) and \(^{153}\text{Gd}\) with filters

The radio active isotopes \(^{109}\text{Cd}\) and \(^{153}\text{Gd}\) are common radio active sources, produced in nuclear reactors. The photons of low energy emitted are the characteristic X-rays of their respective decay products, \(^{109}\text{Ag}\) and \(^{153}\text{Eu}\). Table 5.1 summarises their properties. High resolution spectra can be found in the catalogue by R. L. Heath (1974).

**Table 5.1: Relevant properties of \(^{109}\text{Cd}\) and \(^{153}\text{Gd}\) (Lederer and Shirley, 1978).**

<table>
<thead>
<tr>
<th></th>
<th>(^{109}\text{Cd})</th>
<th>(^{153}\text{Gd})</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Half life</strong></td>
<td>470 days</td>
<td>243 days</td>
</tr>
<tr>
<td><strong>Decay</strong></td>
<td>Electron Capture</td>
<td>Electron Capture</td>
</tr>
<tr>
<td><strong>Decay prod</strong></td>
<td>(^{109}\text{Ag}) (stable)</td>
<td>(^{153}\text{Eu}) (stable)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Energy</th>
<th>Emission rate</th>
<th>Energy</th>
<th>Emission rate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>(\gamma)-rays</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>88.036</td>
<td>3.8</td>
<td>103.180</td>
<td>28</td>
<td></td>
</tr>
<tr>
<td>97.432</td>
<td></td>
<td>69.676</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td><strong>K X-rays</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(K_{\alpha1})</td>
<td>22.1629</td>
<td>53.7</td>
<td>41.5422</td>
<td>56.0</td>
</tr>
<tr>
<td>(K_{\alpha2})</td>
<td>21.9903</td>
<td>28.4</td>
<td>40.9019</td>
<td>31.0</td>
</tr>
<tr>
<td>(K_{\beta1})</td>
<td>24.93</td>
<td>14.6</td>
<td>47.0</td>
<td>17.1</td>
</tr>
<tr>
<td>(K_{\beta2})</td>
<td>25.46</td>
<td>2.6</td>
<td>48.3</td>
<td>4.9</td>
</tr>
</tbody>
</table>

\(K_{\alpha1}\) and \(K_{\alpha2}\) will be considered as one energy. The \(K_{\alpha}\) X-rays can be removed to a large extend by using materials having a sharp increase in the absorption coefficient, the so-called K-edge, between \(K_{\alpha}\) and \(K_{\beta}\). For silver and Europium the materials are Palladium (Pd) and Samarium (Sm) respectively. Table 5.2 gives the resulting emission rates for several filter thicknesses.

A source can thus be obtained with isolated peaks at 22 and 41 keV of arbitrary strength ratio.

Draw-back of the filtering technique is that the intensity of the \(K_{\alpha}\) X-rays decreases. However, not filtering the \(K_{\alpha}\) X-rays, thus considering \(K_{\alpha}\) plus \(K_{\beta}\) as one single energy, results in systematic errors in the composition determination. The properties of the errors if this effect is not taken into
Figure 5.1: Absolute error in the oil fraction caused by adding the $K_u$ and $K_\alpha$ peaks of $^{103}$Cd and $^{153}$Gd. WC=100%, $t_z=5$ cm, $R_1(E_1)=R_1(E_2)$, salinity=0 and 150 kg m$^{-3}$. 
account are:
1. the systematic error is zero for the 100% oil, 100% water and 100% gas point, so small for compositions near those points;

2. the non-linearity at E₁ is larger than at E₂ because the mass absorption coefficient for low γ-energies is a steep function of energy while for higher energies it flattens out (see figure 3.2);

3. the oil fraction is underestimated, mainly in favour of water (see figure 3.1): the measured point is to the left hand side, slightly lower than the actual point, representing a shift from oil to water, almost parallel to the lines of constant gas fraction;

4. the largest errors are on the water-gas line, following from calculations.

Figure 5.1 illustrates the magnitude of the errors at the 100% water cut line (worst case) using the data from section 3.3.1 with two different salinities. The figure shows that the errors are small so the filtering technique is not required for the reduction of this non-linearity.

The $^{109}$Cd-$^{153}$Gd source without filters should be a source eligible for composition measurements, with a large yield of the important energies.

Table 5.2: Emission per 100 disintegrations of $^{109}$Cd and $^{153}$Gd using different filters.

<table>
<thead>
<tr>
<th></th>
<th>$^{109}$Cd</th>
<th>$^{153}$Gd</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$K_α$ (22.1 keV)</td>
<td>$K_α$ (25.0 keV)</td>
</tr>
<tr>
<td>0.0 mm Pd</td>
<td>82.1</td>
<td>17.2</td>
</tr>
<tr>
<td>0.1 mm Pd</td>
<td>16.8</td>
<td>0.031</td>
</tr>
<tr>
<td>0.2 mm Pd</td>
<td>3.8</td>
<td>$5.7 \times 10^{-5}$</td>
</tr>
<tr>
<td>0.0 mm Sm</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.2 mm Sm</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.3 mm Sm</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.4 mm Sm</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure 5.2: Arrangement of the static tests with the $^{109}\text{Cd}-^{153}\text{Gd}$ source.
5.3 Experimental set-up

Static tests have been conducted to test the properties discussed above. A schematic of the arrangement is shown in figure 5.2.

Source

The source consists of two low activity sources:
* 148 MBq (4 mCi) $^{109}$Cd;
* 74 MBq (2 mCi) $^{153}$Gd.

Notice that the detector efficiency of a Si detector of 0.5 mm thickness at 22 keV is about 40% and at 41 keV about 6% (see figure 3.17). The ratio of the effective strength is thus not 2:1 ($^{109}$Cd:$^{153}$Gd) but 15:1. Section 3.3 shows that the activity of the $^{109}$Cd source could have been chosen a factor 15 weaker without loss of precision.

Filters

The following filters were chosen:
* 0.1 and 0.2 mm Pd for $^{109}$Cd;
* 0.2, 0.3 and 0.4 mm Sm for $^{153}$Gd.

In addition there were lead filters to test each source separately.

Detectors

Three different detectors were chosen.
1. 12*0.5 mm$^2$ Si semiconductor detector.
   This is a small volume Si detector with an energy resolution of 2-2.5 keV FWHM. The objective of this detector was to obtain reference spectra and measurements.

2. 100*0.5 mm$^2$ Si semiconductor detector.
   This is a large volume Si detector with an energy resolution of about 12 keV FWHM. This allows just sufficient discrimination between 22 and 41 keV. $^{109}$Cd-$^{153}$Gd is aimed for this detector.

3. NaI(Tl) scintillation detector with photo multiplier.
   This is presently by far the most widely applied radiation detector.

Both Si detectors were PIPS detectors of Canberra. Their pulses were processed by the following Canberra system:
* Preamplifier: 2002;
* Amplifier : 2025 AFT Research Amplifier;
* ADC : AccuSpec A Acquisition Board.

The Si detectors were cooled to about 5°C to reduce resolution loss due to the thermal noise.

The pulses of the photo multiplier were processed by the AccuSpec NaI Plus acquisition board manufactured by Canberra.
Phases

The three components chosen were:
* gas oil;
* demineralised water with no salt added;
* air.
Figure 5.3: Filter tests of $^{109}$Cd and $^{153}$Gd with the 12*0.5 mm$^3$ Si detector.
A - $^{109}$Cd filtered with 0, 0.1 and 0.2 mm Pd;
B - $^{153}$Gd filtered with 0, 0.2, 0.3 and 0.4 mm Sm.
5.4 Measuring results

5.4.1 Filter tests; net peak area determination

Figure 5.3 shows the spectra of $^{109}$Cd and $^{153}$Gd using the different filters, obtained with the $12\times0.5\text{ mm}^3$ Si detector. Figure 5.3 A gives the results for $^{109}$Cd (hiding $^{153}$Gd with lead) and figure 5.3 B for $^{153}$Gd (hiding $^{109}$Cd with lead). It is stressed that these are logarithmic plots and small peaks look more impressive than they are.

For the composition measurements, both sources are measured with one detector. The figures show that there are several sources of non lineairities when the two spectra are combined in one spectrum. Most important are the induced silver X-rays and the Compton edges of the 97 and 103 keV $\gamma$-rays.

The characteristic X-rays of silver (22+24 keV) in the $^{153}$Gd spectrum (figure 5.3 B) are induced in the epoxy used for the contacts in the detector. The intensity is not linear with the intensity of the 22 keV peak of $^{109}$Cd. In future detectors therefore a different epoxy should be used.

The Compton edges of the 97 and 103 keV $\gamma$-rays of $^{153}$Gd are at 27 and 30 keV respectively. Their intensities are not linear with the intensity of the 22 keV X-ray of $^{109}$Cd. The error may become important if the source strength of $^{153}$Gd relative to $^{109}$Cd is increased in order to increase precision.

Figure A1.1 in appendix 1 shows the spectra of the filter tests of the $100\times0.5\text{ mm}^3$ Si detector. Along with the above errors, that are unclear because of the poor resolution, the large volume Si has a noise level of about 14 keV. This can not be interfered from the 22 keV peak. In addition, the resolution is, if no filtering is applied, not sufficient to discriminate between 22+24 keV, 41+47 keV and the induced wolfram X-rays. It should however be remarked that there was a piece of cable between the semiconductor crystal and the first amplification stage. Noise level and resolution will improve if the cable is removed.

Figure A1.2 in appendix 1 shows the spectra of the filter tests of the NaI(Tl) scintillation detector. NaI spectra always show an escape peak, approximately 30 keV below the actual energy. Especially the escape peak of the 47 keV X-ray of $^{153}$Gd interferes with the 21 keV peak.

The function of background subtraction is to get rid of all the non linear effects and to find a parameter that is proportional to the net peak area. Several articles are available on this subject. One class of background subtraction methods fits some detector response function (Blok et al.,

---

1 Several terms from radiation technology will be used. Explanation can be found in the book by G. F. Knoll (1992).
1975; Kowalski and Isenhour, 1968). This requires non-linear least square fitting, taking with the number of parameters (8 or more) several minutes on a 486 PC.

The background subtraction applied in the composition measurements discussed below is, in case of the small volume Si detector and the NaI detector, a simple straight line, taking everything below that line as background. For the large volume Si detector no background subtraction is applied at all. The main reason is that small non-linearities should only result in small errors in the composition (compare the error resulting from adding the Kα and Kβ X-rays, discussed in section 5.2). Further, in dynamic systems, there is no time for time-consuming calculations (non-logarithmic averaging). Important to remark is that if no background subtraction is required, the amplifier and ADC can be replaced by dual energy counter. This considerably increases the simplicity and reliability of the instrument.
Figure 5.4: Composition measurements with the 100×0.5 mm² Si detector.
A - with filters; B - without filters
Oil C and water C represent measurements having constant oil and water fraction respectively.
5.4.2 Composition measurements

With the three detectors the following measurements have been executed with and without filters (chosen were 0.1 mm Pd for $^{109}$Cd and 0.4 mm Sm for $^{155}$Gd):

1. two-phase measurements to compare the composition each energy separately (for two-phase measurements only one energy is necessary);
2. three-phase measurements: water (oil) is added to a two-phase oil-gas (water-gas) mixture, the oil (water) fraction is thus kept constant.

It should be remarked that no reference fractions are available. Reference fractions require very accurate volume measurements. This is not rewarding as for the two-phase mixtures the two independent single-peak composition measurements are available.

Appendix 2 gives the calibration spectra and the tables of the measurements with the small volume Si detector with and without filters. The absolute errors are, with and without filters, within $\pm 1\%$. This error is representative for the experimental errors like temperature, shape of the liquid surface(s), etc.

Figure 5.4 shows the measuring results with the large volume Si detector. Figure 5.4 A with filters and figure 5.4 B without filters. Appendix 2 gives the calibration spectra and the table of the measurement with filters. The absolute errors with filters are within $\pm 1.5\%$ while no background subtraction is applied. The 0.5\% extra is mainly caused by non linear background. The errors without filters are large. The main reasons are the too low resolution and the noise level.

Appendix 2 gives the calibration spectra and tables of the measurements with the NaI(Tl) detector. The absolute errors with filters are within $\pm 1\%$. The absolute errors without filters are within $\pm 1.5\%$. The half percent extra is mainly caused by the escape peak of the 47 keV Gd X-ray.

No unexpected difficulties occur with the determination of composition with the combined $^{109}$Cd–$^{155}$Gd source. The measurements with the small volume Si detector and the NaI(Tl) detector show that it is not necessary to apply the filtering techniques. To use the source unfiltered in combination with the large volume Si detector it is however necessary to improve resolution and the noise level. This improvement probably can be reached by:

* removing the cable between the semiconductor crystal and the pre-amplifier;
* removing the silver from the epoxy;
* careful tuning of the pre-amplifier.

This will probably allow to use $^{109}$Cd–$^{155}$Gd without filters in combination with the 100*0.5 mm$^3$ Si detector and a dual energy counter as the background subtraction applied had little influence.
5.5 Conclusions

* $^{109}$Cd-$^{153}$Gd without filters is a suitable dual energy source for composition measurements.

* $^{109}$Cd-$^{153}$Gd without filters has compared to $^{241}$Am large advantages:
  + environmentally: the half lives are much shorter and the yield of the necessary photons per disintegration is larger;
  + the strength ratio of the two energies can be chosen arbitrarily.

* The ratio of the activity of $^{109}$Cd and $^{153}$Gd should be chosen 1:8 to 16 ($^{109}$Cd:$^{153}$Gd) if the source is applied in combination with a Si detector.

* The combined $^{109}$Cd-$^{153}$Gd source is probably eligible for a dual energy counter and a 100*0.5 mm$^3$ Si detector. Then however the detector has to be improved (no silver in the epoxy, no cable between the crystal and the first amplification stage and a careful tuning of the pre-amplifier).
6 DEGRA COMBINED WITH A VENTURI

6.1 Introduction

In literature, little experimental data are available on the combination of a venturi velocity measurement with a DEGRA composition measurement (Rafa, 1989). No experiments are available for the specific conditions expected in the in-line-separator (GVF<30%, 0%<WC<100%, velocity in a 3” line 0.014 to 1.4 m s\(^{-1}\)). Therefore experiments were conducted to test the eligibility of this measuring principle for the ILS. The objectives of the measurements are:

1. gather experimental data on the influence of the concentration profile of the gas phase and non-logarithmic averaging;

2. test the eligibility of Si detectors for field use, as the application of Si detectors under field conditions is new;

3. investigate if one oil and one water calibration comply for the different wells in a field;

4. determine the accuracy of the venturi velocity measurement.

The next sections present two test series. The first is a flow loop test in the three-phase test loop Donau at KSEPL. The second is a field test at the NAM production location in Berkel.
Figure 6.1: Schematic of the test section in the three-phase test-loop.
6.2 Flow loop test

6.2.1 Experimental set-up

A schematic of the flow loop test section is shown in figure 6.1.

Gas injection

Gas was injected through a 30 cm long piece of pipe with a porous material on the inside. The bubble diameter was appreciably larger than the 0.5 mm design parameter of the ILS. This increases the effect of non-logarithmic averaging and the effect of a gas concentration profile, causing larger errors than are expected in the ILS.

Mixer

The fabric of the mixer is unknown. When below mixed points are discussed, the fluid has passed within about 7 cm a hole of about half the pipe diameter on one side of the tube, a disk with holes of about 0.5 cm diameter and a hole of about half the pipe diameter on the other side of the tube. It is an asymmetrical mixer.

Venturi

The measures of the venturi are indicated in figure 6.2. The DEGRA system is installed over the throat of the venturi. The wall material of the throat therefore consists of RCFE (see section 3.8.2).

DEGRA

Figure 6.3 shows the arrangement of the DEGRA. The source is a 6.5 GBq (175 mCi) $^{241}$Am source and the detectors are three small volume ($12 \times 0.5$ mm$^2$) Si detectors. Initially there were two differences between these detectors and the detectors described in section 5.3:

1. the detector was glued on a semiconductor that allowed to cooling using the Peltier effect;
2. the connections were glued to the crystal using a copper epoxy.

The copper epoxy however came loose and it was replaced with the more common silver epoxy with characteristic X-rays at 22 and 25 keV. In future, bonding will be a much more reliable option. Each detector has its own pre-amplifier, amplifier and ADC. Apart from the amplifier, a 2026 from Canberra, the same type of instrumentation is used as described in section 5.3.

Phases

* Oil : Gas oil
* Water : Tap water
* Gas : Air
Figure 6.2: Venturi measures.

Figure 6.3: Arrangement of the DEGRA.
Reference measurements

The reference flow rates were measured by:
* oil : turbine meter;
* water : turbine meter;
* gas  : mass flow meter.
The inaccuracy of these instruments is below 0.5%.
Figure 6.4: Test loop calibration spectra of the middle detector.
6.2.2 Composition measurements

Figure 6.4 shows the three calibration spectra of the middle detector. Notice that the intensity of $E_2$ (59.5 keV) for the gas calibration is smaller than the intensity of $E_1$ (17.8 keV). This is uneconomical from a statistical point of view (see section 3.3). In future this should be overcome by integrating the small volume Si detector on a large volume Si detector. The latter then just measures the 59.5 keV peak (see section 3.8).

Figure 6.5 shows the compositions measured with the middle detector, figure 6.5 A without and figure 6.5 B with mixing (similar figures were measured for the two side detectors). The small black triangles represent the measured composition and the circles the homogeneous reference composition.

The composition in this triangle follows in exactly the same way as described in section 3.2.1. Horizontal lines, parallel to the line connecting the 100% oil and 100% water point are lines with equal gas fraction. The gas fraction increases linearly from 0% at the bottom of the triangle to 100% at the top. Just a horizontal shift between reference and measurement represents thus just a shift in water cut. Similar reasonings hold for the water and oil fraction. Figure 6.5 shows lines with equal oil, water and gas fraction with steps of 10%.

A line from the 100% gas point to any point at the 0% gas line represents a line with constant water cut. Just a shift along this line between reference and measurement, corresponds to a shift between liquid and gas. Figure 6.5 shows lines with equal water cut steps of 10%.

Each measured composition in figure 6.5 is an average of 10 measurements of 30 s real detector time (actual time is longer, mainly because of the dead time of the detector). The statistical uncertainty is negligible.

The two main causes of differences between the measured and the homogeneous volume fractions are:
1. non-logarithmic averaging, causing mainly a shift from water to oil (see section 3.5);
2. concentration and velocity profile of gas, causing just a shift from liquid to gas (see section 3.6).

The influence of non-logarithmic averaging is striking, even at low gas volume fractions. Figure 6.5 A shows a large shift from water to oil and water. The model from section 3.5 estimates a bubble diameter of about 3-4 mm (compare figure 6.5 A with figure 3.13 and 3.14). The mixer breaks the bubbles up and in figure 6.5 B the shift has completely vanished. Non-logarithmic averaging, even in bubble flow, seriously hampers the water cut determination and a correction is necessary.

The magnitude errors caused by non-logarithmic averaging in
Figure 6.5: DEGRA composition measurements under flowing conditions. 
A - unmixed; B - mixed.
figure 6.5 A is not representative for the ILS because the bubble diameter in the ILS is expected to be much smaller. Important qualitative results are:
1. the shift between water and oil does occur, even in bubble flow;
2. the shift reproduces, corrections are thus possible if the errors in the ILS application are large.

Figure 6.5 B clearly shows the influence of a concentration profile of the gas phase. The interpretation is however difficult because the measured fractions are compared to the homogeneous fractions. Differences are caused by concentration and velocity profiles.

The ILS requires an accuracy of 3-4% in effective GVF to determine liquid flow rate with 1-2% accuracy (see section 4.3). Figure 6.5 shows that the differences between the measured and the homogeneous gas volume fraction reproduce and hardly depend on water cut. The errors caused by a concentration profile are thus unimportant provided a simple (water cut independent) correction is applied. Errors in water cut however should be carefully examined in the ILS testing.
Figure 6.6: Venturi velocity measurements in the test loop. 
A - using the homogeneous reference composition; 
B - using the corrected DEGRA composition. 
The quotient of the measured and the actual superficial liquid velocity is plotted as a function of the gas volume fraction.
6.2.3 Velocity measurements

Figure 6.6 shows the measured superficial liquid velocity divided by the actual superficial liquid velocity. Figure 6.6 A uses the homogeneous composition from the reference measurements. Figure 6.6 B uses the DEGRA composition with a linear, water cut independent correction of the gas fraction ($\alpha^*=c\alpha$ with $c=0.8$). These are all unmixed measurements. No velocity measurements are available on the mixed measurements as the mixer appeared to have disturbed the lower leg of the Dp cell.

The superficial liquid velocity is derived from equation 4.12 with:

* $C_d=0.98$ (the mean between the oil and water one-phase discharge coefficients);
* $S=1$ (no slip condition);
* $n=1$ (isothermal flow (Davies, 1967; Eddington, 1970)).

Further data are:

+ $v_i+v_g$ (in a 3" line) 1 to 1.5 m s$^{-1}$
+ line pressure 0.12 MPa
+ line temperature 40 to 55 °C
+ pressure drop venturi 1 to 6 kPa
+ pressure recovery not measured
+ oil base density 844 kg m$^{-3}$
+ salinity 0 kg m$^{-3}$

Figure 6.6 A shows that the measured velocities are up to about 40% GVF within ±2%. The errors in figure 6.6 B are slightly larger. This is however mainly caused by the erroneous liquid density caused by the error in water cut due to non-logarithmic averaging. The simple linear correction of the gas fraction to obtain an effective gas volume fraction is thus sufficient. The correction for friction with a constant discharge coefficient derived from single-phase measurements is for these measurements sufficient. The errors due to friction may however increase for the more viscous crude in the field.
Figure 6.7: Schematic of the test section in the field.
6.3 Field test

6.3.1 Experimental set-up

A schematic of the test section is shown in figure 6.7. This section was installed between the test separator and the storage tank. Venturi and DEGRA are the same as described in section 6.2.1.

Reference measurements

The instruments that should give the reference measurements were:
* water cut: OMEGA tube (see figure 6.7: the liquid density is derived from hydrostatic head plus friction over the upward leg and head minus friction over the downward leg);
* liquid velocity: turbine meter;
* gas velocity: vortex meter.

The OMEGA tube can not handle gas volume fractions over 2%. The gas volume fraction at the outlet of the test separator however appeared to be larger, probably due to incomplete separation and gas breakout. The only water cut figures available were therefore the production data (obtained by taking samples). Further, the vortex meter needs a minimum flow so only gas volume fractions over approximately 12% could be measured.

Test separator

A test separator has usually two operation modes, continuous mode and dump mode.

Continuous mode regulates the liquid level in the test separator at a constant value. This means that there should be a reasonably constant outflow. The automatic control valve of the test separator used in the experiment was however closed approximately half of the time. This mode is therefore hardly used for testing because it is equal to dump mode only with a smaller time step (≈2 minutes). Further, in this mode, no stable gas injection was possible.

Dump (batch or test) mode dumps an amount of liquid (in the experiments below about 400 kg) and then fills up again. This mode is used in most of the experiments for it allowed a stable liquid flow rate and gas injection rate.
Figure 6.8: Field test water calibration spectrum of the middle detector.
6.3.2 Calibrations

Before installing the DEGRA system in the flow line, oil and water calibrations were executed for several wells.

The salinity of the water was approximately 90 kg m\(^{-3}\). This seriously hampers the water calibration because the fraction of the incident 17.8 keV photons transmitted is only 0.10% and 0.19% for the middle and side detector respectively. Figure 6.8 shows the water calibration spectrum of the middle detector. It appears to be extremely difficult to determine net peak area of the 17.8 keV peak. There is a nice looking low energy peak. This is however the 22 keV Ag X-ray induced in the detector, not the 20.8 keV Np X-ray from \(^{241}\)Am.

From the side detectors the net peak area of the 17.8 keV could be determined. Table 6.1 summarises the calibration count rates of one side detector.

Table 6.1: Calibration count rates

<table>
<thead>
<tr>
<th></th>
<th>Count rate E1 in s(^{-1})</th>
<th>Count rate E2 in s(^{-1})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production water</td>
<td>32.8</td>
<td>3052</td>
</tr>
<tr>
<td>Well 9</td>
<td>27.8</td>
<td>3116</td>
</tr>
<tr>
<td>Well 17</td>
<td>29.9</td>
<td>3126</td>
</tr>
<tr>
<td>Well 20</td>
<td>30.4</td>
<td>3135</td>
</tr>
<tr>
<td>Production water</td>
<td>36.7</td>
<td>3153</td>
</tr>
<tr>
<td>Oil:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stat. oil</td>
<td>3648</td>
<td>3739</td>
</tr>
<tr>
<td>Well 5</td>
<td>1876</td>
<td>3693</td>
</tr>
<tr>
<td>Well 9</td>
<td>2944</td>
<td>3734</td>
</tr>
<tr>
<td>Well 15</td>
<td>3433</td>
<td>3761</td>
</tr>
<tr>
<td>Well 17</td>
<td>3307</td>
<td>3744</td>
</tr>
<tr>
<td>Well 19</td>
<td>3222</td>
<td>3760</td>
</tr>
<tr>
<td>Stat. oil</td>
<td>3640</td>
<td>3754</td>
</tr>
</tbody>
</table>

Table 6.1 shows that, when account is taken for the approximately 3% water not separated from the oil samples, there is little difference between the oil calibrations of different wells. Well 5 does show a large deviation but this well was just drilled. The systematic errors resulting from the above spread are for the oil calibration within \(\pm 1.5\%\) in the 100% oil point. These are, considering the circumstances,
acceptable. No large errors are made when one oil calibration is used for the whole field. The spread in the water calibrations causes systematic errors within ±5% in the 100% water point. Background subtraction as well as salinity differences contribute to this error.
Figure 6.9: DEGRA composition measurements under flowing conditions.
A - 3% WC well; B - 29% WC well;
C (on next page) - 70% WC well.
6.3.3 Composition measurements

A number of measurements with several wells and well-combinations have been conducted. Figure 6.9 shows three representative series. A, B and C have 3%, 30% and 70% water cut respectively.

Several dumps are shown with and without gas injection. One dump takes about 2 minutes. The turbine and vortex measurements are 10 s averages so there are about 10 reference point per dump. The DEGRA points are averages over 4 measurements of 3 seconds real detector time. They take 5-6 actual seconds because of the dead time of the ADC and computer time (especially communication of the computer with the ADC). There are thus 4 to 6 DEGRA points per dump.

The points are from one side detector (see figure 6.3). This detector showed clear signs of erroneous calibrations. Under no flow conditions without gas injection it measured negative gas fractions of 5-12% (dependent on water cut). The two other detectors showed a large change in resolution and gave very bad results. The reason was probably bad wiring because back in the laboratory everything was normal again.

Figure 6.9 clearly shows the change in water cut due to non-logarithmic averaging. The influence of a concentration profile of the gas phase however is not clear because the absolute gas fractions are distorted by the erroneous calibration.

The 30% WC figure differs from the other two figures (as do other measurements with 25-40% WC). The reason is probably a combination of the high viscosity of an oil-water mixture near the transition of oil continuous to water continuous and the (very) close gas injection point.

The two important results that follow from these pictures are:
1. Si detectors are eligible for field use provided they are carefully wired (a change in pulse shape due to some noise can have an effective influence of a change in detector efficiency);
2. the fact that it is impossible to redo calibrations is a large constraint on the system. Errors are systematic and mostly well (not water cut) independent. Correction is difficult especially if little is known of the mixture.
Figure 6.10: Venturi velocity measurements using the homogeneous reference composition. The quotient of the measured and the turbine superficial liquid velocity is plotted as a function of gas volume fraction.
6.3.4 Velocity measurements

Figure 6.10 shows the measured superficial liquid velocity divided by the actual superficial liquid velocity. These are the points shown earlier in figure 6.9 leaving out the points where the vortex meter is not in its range.

The superficial liquid velocity is calculated from equation 2.12. The discharge coefficient is taken equal to the discharge coefficient used in the laboratory. The homogeneous composition is used that follows from production water cut, turbine and vortex meter.

Further data are:
+ $v_{el} + v_{eq}$ (in a 3" line) 1 to 1.75 m s$^{-1}$
+ line pressure 0.4 MPa
+ line temperature 45 to 55 °C
+ pressure drop venturi 1 to 8 kPa
+ pressure recovery not measured
+ oil base density 930 kg m$^{-3}$
+ salinity 90 kg m$^{-3}$

Figure 6.10 leads to the conclusions that:
1. the errors are small for higher GVF;
2. friction, especially with 25-40% water cut causes some problems.

It should however be remarked that a turbine meter is not eligible for crude oil and is gas sensitive while the gas volume fraction in the liquid stream was larger than 2%. To obtain more reliable figures of the accuracy of the venturi velocity measurements and the influence of friction, it is necessary to redo the measurements with a better reference.
6.4 Conclusions

* The DEGRA composition measurements show, due to non-logarithmic averaging, large errors in the water cut, even in bubble flow. The errors are however systematic and can be reproduced. Probably a correction can be found.

* A simple water cut independent correction for the void fraction profile results in accurate liquid velocity figures.

* The venturi velocity measurements in the laboratory show relative errors within ±2%.

* One single oil calibration can be used for all the wells at the Berkel location.

* Si detectors are probably eligible for field use. Wiring should however be performed very carefully.

* A large constraint of the DEGRA system is that it is impossible to redo calibrations.

# More measurements with a better reference are necessary to determine the accuracy of the venturi velocity measurement with the viscous crude in the field.
7. CONCLUSIONS & POINTS FOR FURTHER RESEARCH

* The two γ-energies $E_1$ and $E_2$ ($E_1 < E_2$) for DEGRA composition measurements should be chosen as follows:
  - determine the composition with the largest absorption at $E_1$ expected (not necessarily 100% water);
  - calculate for this composition the $E_1$ that minimises the statistical uncertainty in the fractions, using an arbitrary but high $E_2$;
  - choose the source having a γ-energy as close as possible to this energy;
  - if this source has a sufficiently strong high energy this source can be used for the composition measurements, else, for $E_2$, some convenient other source with a sufficiently high γ-energy can be chosen. Attention should be paid to the fact that to reduce the statistical uncertainty in the composition, the intensity of $E_2$ should be chosen higher (approximately a factor 2) than the intensity of $E_1$.

* On production locations, Si detectors have large advantages over scintillation detectors. However, because of the low efficiency of Si for high γ-energies, this detector is limited to diameters smaller than 5 cm if high water fractions are expected. Future experiments should show whether CdTe or HgI$_2$ detectors are good alternatives.

* The combined source of $^{109}$Cd (22 keV) and $^{153}$Gd (41 keV) is, without applying filtering techniques a suitable dual energy source for composition measurements. Small alterations of the 100*0.5 mm$^2$ Si detector should allow to use $^{109}$Cd-$^{153}$Gd with this detector and a dual energy counter.

* The main sources of error of the DEGRA composition measurements under flowing conditions are:
  - calibrations that do not hold for the actual situation: presently it is impossible to redo calibrations, especially salinity changes then cause large errors in the composition determination;
  - non-logarithmic averaging: even in bubble flow this causes large absolute errors in the water cut (up to 30%). The errors are systematic and reproduce. Future experiments should show if a convenient correction can be found.

* DEGRA composition measurements, combined with a venturi velocity measurement for OWG mixtures with low (<40%) GVF give in the laboratory liquid production figures within ±2%. Preliminary experiments in the field show that this accuracy can be maintained for the more viscous crude. More measurements are however necessary.

# It recommended to investigate whether in two-phase flow, non-logarithmic averaging can be used for the measurement of bubble size distribution parameters.
LIST OF SYMBOLS

\[ \hat{A} \] Calibration matrix

\[ A_{1,2} \] Area inlet (1), throat(2) of the venturi \[ \text{[m}^2\text{]} \]

\[ a \] Arbitrary positive number \[ [-] \]

\[ b \] Arbitrary positive number \[ [-] \]

\[ C \] Salinity \[ \text{[kg m}^{-3}\text{]} \]

\[ c_0 \] Discharge coefficient \[ [-] \]

\[ D \] Determinant of the matrix to the left hand side of equation 2.10 \[ \text{ln}^2(\text{counts s}^{-1}) \]

\[ d \] Diameter of the gas bubbles \[ \text{[m]} \]

\[ E \] Energy of the \( \gamma \)- or X-rays \[ \text{[keV]} \]

\[ G_i \] Logarithm of the count rate of the gas calibration at \( \gamma \)-energy \( i \) \[ \text{ln}(\text{counts s}^{-1}) \]

\[ g \] Acceleration of gravity \[ \text{[m s}^{-2}\text{]} \]

\[ h \] Heigh \[ \text{[m]} \]

\[ I(E) \] Intensity of the radiation at energy \( E \) \[ \text{[photons s}^{-1}\text{]} \]

\[ I_i(E) \] Intensity of the incident radiation at energy \( E \) \[ \text{[photons s}^{-1}\text{]} \]

\[ M_i \] Logarithm of the count rate of the measurement at \( \gamma \)-energy \( i \) \[ \text{ln}(\text{counts s}^{-1}) \]

\[ m \] Measuring vector \[ [-] \]

\[ m_i \] Mass flow rate of species \( i \) \[ \text{[kg s}^{-1}\text{]} \]

\[ N \] Number of measurements \[ [-] \]

\[ n \] Profile exponent in equation 3.24 \[ [-] \]

\[ n \] Compression index \[ [-] \]

\[ O_i \] Logarithm of the count rate of the oil calibration at \( \gamma \)-energy \( i \) \[ \text{ln}(\text{counts s}^{-1}) \]

\[ p \] Fluid pressure \[ \text{[kg m}^{-2}\text{ s}^{-2}\text{]} \]

\[ \bar{p} \] Reduced fluid pressure \[ [-] \]

\[ Q \] Volumetric flow rate \[ \text{[m}^3\text{ s}^{-1}\text{]} \]

\[ R(E) \] Count rate at energy \( E \) \[ \text{[photons s}^{-1}\text{]} \]

\[ R_i(E) \] Count rate at energy \( E \) in absence of any absorbing material \[ \text{[photons s}^{-1}\text{]} \]

\[ R \] Radius of pipe \[ \text{[m]} \]

\[ r \] Radial distance in cylindrical co-ordinates \[ \text{[m]} \]

\[ S \] Velocity ratio defined by equation 4.4 \[ [-] \]

\[ T \] Temperature \[ \text{[°C]} \]

\[ t \] Thickness \[ \text{[m]} \]

\[ v \] Velocity \[ \text{[m s}^{-1}\text{]} \]

\[ W_i \] Logarithm of the count rate of the water calibration at \( \gamma \)-energy \( i \) \[ \text{ln}(\text{counts s}^{-1}) \]

\[ \mathbf{W} \] Water calibration vector \[ [-] \]

\[ w \] Proportion by weight \[ [-] \]

\[ x \] Density thickness \[ \text{[kg m}^{-2}\text{]} \]

\[ z \] Rectangular co-ordinate \[ \text{[m]} \]

\[ \alpha \] Volume fraction \[ [-] \]

\[ a \] Fraction vector \[ [-] \]

\[ \epsilon \] Void fraction \[ [-] \]

\[ \eta(E) \] Detector efficiency at energy \( E \) \[ \text{counts photon}^{-1}\text{]} \]

\[ \lambda \] Number between 0 and 1 \[ [-] \]

\[ \mu \] Linear absorption coefficient \[ \text{[m}^{-1}\text{]} \]
\( \mu \) Mean (just in equation 3.23) [-]
\( \rho \) Density [kg m\(^{-3}\)]
\( \sigma \) Standard deviation
\( \tau \) Counting time [s]

Subscripts:
- \( a \) Actual
- \( c \) Calculated
- \( e \) Electron
- \( f \) Fluid
- \( g \) Gas
- \( i \) Index
- \( l \) Liquid
- \( o \) Oil
- \( p \) Pipe
- \( s \) Superficial
- \( v \) Vacuum
- \( w \) Water
- \( w \) Wall (just in equation 3.25)
- \( 0 \) Middle of the pipe
- \( 1 \) \( \gamma \)-energy 1
- \( 2 \) \( \gamma \)-energy 2
- \( 3 \) \( \gamma \)-energy 3
REFERENCES


Canberra: via Canberra-Packard, Tilburg, The Netherlands.


Nales R. (1991), Shell report.


Figure A1.1: Filter tests of $^{109}$Cd and $^{153}$Gd with the 100*0.5 mm$^3$ Si detector.
A - $^{109}$Cd filtered with 0, 0.1 and 0.2 mm Pd;
B - $^{153}$Gd filtered with 0, 0.2, 0.3 and 0.4 mm Sm.
Appendix 1: Filter tests with 100*0.5 mm² Si and NaI
Figure A1.2: Filter tests of $^{109}$Cd and $^{153}$Gd with the NaI(Tl) detector.
A - $^{109}$Cd filtered with 0, 0.1 and 0.2 mm Pd;
B - $^{153}$Gd filtered with 0, 0.2, 0.3 and 0.4 mm Sm.
Figure A2.1: Calibration spectra of the combined $^{109}$Cd-$^{153}$Gd source with the 12*0.5 mm$^3$ Si detector. A - with filters (0.1 mm Pd and 0.4 mm Sm); B - without filters.
Appendix 2: Measuring results with the $^{109}$Cd-$^{153}$Gd source

Below the tables are given with the compositions measured with the $^{109}$Cd-$^{153}$Gd source:

* O$_i$ represent 2-phase oil-gas mixtures;
* W$_i$ represent 2-phase water-gas mixtures;
* L$_i$ represent 2-phase oil-water mixtures;
* OC$_i$ represent compositions with constant oil fraction;
* WC$_i$ represent compositions with constant water fraction.

Notice that the compositions with and without filters should be equal.

Table A2.1: Measurements with the small volume Si detector with filters.

<table>
<thead>
<tr>
<th>3-PHASE COMPOSITION</th>
<th>2-PHASE COMPOSITION</th>
<th>2-PHASE COMPOSITION</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>22 keV FROM Cd</td>
<td>41 keV FROM Gd</td>
</tr>
<tr>
<td></td>
<td>oil</td>
<td>water</td>
</tr>
<tr>
<td>O1</td>
<td>48.0</td>
<td>-0.6</td>
</tr>
<tr>
<td>W1</td>
<td>-1.0</td>
<td>47.7</td>
</tr>
<tr>
<td>L1</td>
<td>48.7</td>
<td>51.5</td>
</tr>
<tr>
<td>WC1</td>
<td>0.3</td>
<td>33.0</td>
</tr>
<tr>
<td>WC2</td>
<td>20.6</td>
<td>33.9</td>
</tr>
<tr>
<td>WC3</td>
<td>37.7</td>
<td>33.8</td>
</tr>
<tr>
<td>WC4</td>
<td>66.1</td>
<td>33.9</td>
</tr>
<tr>
<td>OC1</td>
<td>27.6</td>
<td>0.3</td>
</tr>
<tr>
<td>OC2</td>
<td>26.7</td>
<td>21.1</td>
</tr>
<tr>
<td>OC3</td>
<td>27.4</td>
<td>32.7</td>
</tr>
<tr>
<td>OC4</td>
<td>26.2</td>
<td>47.6</td>
</tr>
<tr>
<td>OC5</td>
<td>26.6</td>
<td>73.1</td>
</tr>
</tbody>
</table>

Table A2.2: Measurements with the small volume Si detector without filters.

<table>
<thead>
<tr>
<th>3-PHASE COMPOSITION</th>
<th>2-PHASE COMPOSITION</th>
<th>2-PHASE COMPOSITION</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>22 keV FROM Cd</td>
<td>41 keV FROM Gd</td>
</tr>
<tr>
<td></td>
<td>oil</td>
<td>water</td>
</tr>
<tr>
<td>O1</td>
<td>48.9</td>
<td>0.2</td>
</tr>
<tr>
<td>W1</td>
<td>-1.4</td>
<td>47.4</td>
</tr>
<tr>
<td>L1</td>
<td>48.4</td>
<td>51.1</td>
</tr>
<tr>
<td>WC1</td>
<td>0.4</td>
<td>33.3</td>
</tr>
<tr>
<td>WC2</td>
<td>19.7</td>
<td>34.8</td>
</tr>
<tr>
<td>WC3</td>
<td>37.1</td>
<td>34.0</td>
</tr>
<tr>
<td>WC4</td>
<td>66.4</td>
<td>34.6</td>
</tr>
<tr>
<td>OC1</td>
<td>27.7</td>
<td>0.4</td>
</tr>
<tr>
<td>OC2</td>
<td>26.5</td>
<td>21.5</td>
</tr>
<tr>
<td>OC3</td>
<td>27.2</td>
<td>31.8</td>
</tr>
<tr>
<td>OC4</td>
<td>26.0</td>
<td>47.3</td>
</tr>
<tr>
<td>OC5</td>
<td>26.2</td>
<td>73.1</td>
</tr>
</tbody>
</table>
Figure A2.2: Calibration spectra of the combined $^{109}$Cd–$^{153}$Gd source with the 100*0.5 mm³ Si detector. A - with filters (0.1 mm Pd and 0.4 mm Sm); B - without filters.
Table A2.3: Measurements with the large volume Si detector with filters.

<table>
<thead>
<tr>
<th></th>
<th>3-PHASE COMPOSITION</th>
<th>2-PHASE COMPOSITION 22 keV FROM Cd</th>
<th>2-PHASE COMPOSITION 41 keV FROM Gd</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>oil</td>
<td>water</td>
<td>air</td>
</tr>
<tr>
<td>W1</td>
<td>0.1</td>
<td>8.6</td>
<td>91.3</td>
</tr>
<tr>
<td>W2</td>
<td>1.6</td>
<td>16.7</td>
<td>81.8</td>
</tr>
<tr>
<td>W3</td>
<td>0.9</td>
<td>25.7</td>
<td>73.4</td>
</tr>
<tr>
<td>W4</td>
<td>1.1</td>
<td>34.3</td>
<td>64.6</td>
</tr>
<tr>
<td>W5</td>
<td>0.1</td>
<td>43.5</td>
<td>56.4</td>
</tr>
<tr>
<td>W6</td>
<td>0.0</td>
<td>52.1</td>
<td>47.8</td>
</tr>
<tr>
<td>W7</td>
<td>-0.6</td>
<td>61.2</td>
<td>39.5</td>
</tr>
<tr>
<td>W8</td>
<td>-0.9</td>
<td>69.9</td>
<td>30.9</td>
</tr>
<tr>
<td>W9</td>
<td>-0.4</td>
<td>78.2</td>
<td>22.2</td>
</tr>
<tr>
<td>W10</td>
<td>0.5</td>
<td>86.2</td>
<td>13.4</td>
</tr>
<tr>
<td>O1</td>
<td>3.0</td>
<td>2.3</td>
<td>94.7</td>
</tr>
<tr>
<td>O2</td>
<td>11.8</td>
<td>2.0</td>
<td>86.2</td>
</tr>
<tr>
<td>O3</td>
<td>21.3</td>
<td>1.4</td>
<td>77.4</td>
</tr>
<tr>
<td>O4</td>
<td>31.2</td>
<td>0.7</td>
<td>68.1</td>
</tr>
<tr>
<td>O5</td>
<td>40.4</td>
<td>0.2</td>
<td>59.3</td>
</tr>
<tr>
<td>O6</td>
<td>48.8</td>
<td>0.3</td>
<td>50.8</td>
</tr>
<tr>
<td>O7</td>
<td>57.8</td>
<td>0.1</td>
<td>42.1</td>
</tr>
<tr>
<td>O8</td>
<td>68.3</td>
<td>-0.8</td>
<td>32.5</td>
</tr>
<tr>
<td>O9</td>
<td>75.9</td>
<td>-0.2</td>
<td>24.4</td>
</tr>
<tr>
<td>L1</td>
<td>81.0</td>
<td>19.2</td>
<td>-0.2</td>
</tr>
<tr>
<td>L2</td>
<td>72.0</td>
<td>28.0</td>
<td>0.0</td>
</tr>
<tr>
<td>L3</td>
<td>62.7</td>
<td>37.1</td>
<td>0.2</td>
</tr>
<tr>
<td>L4</td>
<td>54.1</td>
<td>45.7</td>
<td>0.2</td>
</tr>
<tr>
<td>L5</td>
<td>46.3</td>
<td>53.8</td>
<td>-0.1</td>
</tr>
<tr>
<td>L6</td>
<td>36.6</td>
<td>63.1</td>
<td>0.3</td>
</tr>
<tr>
<td>L7</td>
<td>27.7</td>
<td>71.9</td>
<td>0.4</td>
</tr>
<tr>
<td>L8</td>
<td>21.5</td>
<td>79.0</td>
<td>-0.5</td>
</tr>
<tr>
<td>WC1</td>
<td>-0.1</td>
<td>35.0</td>
<td>65.1</td>
</tr>
<tr>
<td>WC2</td>
<td>5.2</td>
<td>37.0</td>
<td>57.8</td>
</tr>
<tr>
<td>WC3</td>
<td>15.6</td>
<td>34.9</td>
<td>49.5</td>
</tr>
<tr>
<td>WC4</td>
<td>22.4</td>
<td>35.8</td>
<td>41.8</td>
</tr>
<tr>
<td>WC5</td>
<td>31.3</td>
<td>35.8</td>
<td>32.9</td>
</tr>
<tr>
<td>WC6</td>
<td>38.7</td>
<td>36.3</td>
<td>25.0</td>
</tr>
<tr>
<td>WC7</td>
<td>47.8</td>
<td>36.3</td>
<td>15.9</td>
</tr>
<tr>
<td>OC1</td>
<td>32.0</td>
<td>0.2</td>
<td>67.8</td>
</tr>
<tr>
<td>OC2</td>
<td>28.7</td>
<td>12.7</td>
<td>58.6</td>
</tr>
<tr>
<td>OC3</td>
<td>31.0</td>
<td>19.3</td>
<td>49.6</td>
</tr>
<tr>
<td>OC4</td>
<td>29.6</td>
<td>28.7</td>
<td>41.7</td>
</tr>
<tr>
<td>OC5</td>
<td>29.5</td>
<td>37.6</td>
<td>33.0</td>
</tr>
<tr>
<td>OC6</td>
<td>30.6</td>
<td>45.4</td>
<td>24.0</td>
</tr>
<tr>
<td>OC7</td>
<td>29.6</td>
<td>54.4</td>
<td>16.0</td>
</tr>
</tbody>
</table>
Figure A2.3: Calibration spectra of the combined $^{109}$Cd–$^{152}$Gd source with the NaI(Tl) detector. A - with filters (0.1 mm Pd and 0.4 mm Sm); B - without filters.
Table A2.4: Measurements with the NaI detector with filters.

<table>
<thead>
<tr>
<th></th>
<th>3-PHASE COMPOSITION</th>
<th>2-PHASE COMPOSITION 22 keV FROM Cd</th>
<th>2-PHASE COMPOSITION 41 keV FROM Gd</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>oil water gas</td>
<td>oil water gas</td>
<td>oil water gas</td>
</tr>
<tr>
<td>O1</td>
<td>37.3 1.5 61.2</td>
<td>40.4 59.6</td>
<td>39.3 60.7</td>
</tr>
<tr>
<td>W1</td>
<td>-0.1 50.0 50.1</td>
<td>50.0 50.0</td>
<td>50.0 50.0</td>
</tr>
<tr>
<td>L1</td>
<td>47.7 52.4 -0.1</td>
<td>47.4 52.6</td>
<td>47.2 52.8</td>
</tr>
<tr>
<td>WC1</td>
<td>0.2 33.1 66.7</td>
<td>33.2 66.8</td>
<td>33.2 66.8</td>
</tr>
<tr>
<td>WC2</td>
<td>12.7 35.3 51.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WC3</td>
<td>32.2 34.6 33.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WC4</td>
<td>49.5 35.0 15.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WC5</td>
<td>66.0 34.8 -0.7</td>
<td>64.6 35.4</td>
<td>63.3 36.7</td>
</tr>
<tr>
<td>OC1</td>
<td>30.8 0.9 68.3</td>
<td>32.7 67.3</td>
<td>32.1 67.9</td>
</tr>
<tr>
<td>OC2</td>
<td>29.8 18.6 51.6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC3</td>
<td>30.1 35.7 34.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC4</td>
<td>30.1 53.2 16.6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC5</td>
<td>31.9 67.7 0.5</td>
<td>32.8 67.2</td>
<td>33.6 66.4</td>
</tr>
</tbody>
</table>

Table A2.5: Measurements with the NaI detector without filters.

<table>
<thead>
<tr>
<th></th>
<th>3-PHASE COMPOSITION</th>
<th>2-PHASE COMPOSITION 22 keV FROM Cd</th>
<th>2-PHASE COMPOSITION 41 keV FROM Gd</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>oil water gas</td>
<td>oil water gas</td>
<td>oil water gas</td>
</tr>
<tr>
<td>O1</td>
<td>39.0 0.6 60.4</td>
<td>40.3 59.7</td>
<td>39.9 60.1</td>
</tr>
<tr>
<td>W1</td>
<td>-0.7 49.7 51.0</td>
<td>49.4 50.6</td>
<td>49.2 50.8</td>
</tr>
<tr>
<td>L1</td>
<td>50.5 49.8 -0.3</td>
<td>49.9 50.1</td>
<td>49.3 50.7</td>
</tr>
<tr>
<td>WC1</td>
<td>0.3 32.5 67.1</td>
<td>32.7 67.3</td>
<td>32.8 67.2</td>
</tr>
<tr>
<td>WC2</td>
<td>13.7 34.5 51.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WC3</td>
<td>31.3 34.5 34.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WC4</td>
<td>49.4 34.4 16.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WC5</td>
<td>67.2 33.3 -0.5</td>
<td>66.3 33.7</td>
<td>65.5 34.5</td>
</tr>
<tr>
<td>OC1</td>
<td>28.2 2.0 69.9</td>
<td>32.4 67.6</td>
<td>30.9 69.1</td>
</tr>
<tr>
<td>OC2</td>
<td>27.6 19.5 52.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC3</td>
<td>30.0 35.1 34.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC4</td>
<td>31.4 51.5 17.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC5</td>
<td>35.4 64.2 0.4</td>
<td>36.1 63.9</td>
<td>36.8 63.2</td>
</tr>
</tbody>
</table>