In-Situ Fluid Property Measurement

Report for Department for Business, Energy & Industrial Strategy

National Engineering Laboratory

Department for Business, Energy & Industrial Strategy

FUNDED BY BEIS

Reference: 2019/767
Project No: FNRE01

Date: December 2019

Information

This report is issued as part of the contract under which the work has been carried out for the client by TUV SUD Limited trading as TÜV SÜD National Engineering Laboratory (‘NEL’).

Notes

1 This report may be published in full by the client unless it includes information supplied in confidence by NEL or any third party. Such information, if included within the report, shall be identified as confidential by NEL.

2a The prior written consent of NEL shall be obtained by the client before publication by them of any extract from, or abridgement of, this report.

2b The prior written consent of NEL shall be obtained by the client before publication:

- Where such publication is made in connection with any public enquiry, legal proceedings or arbitration.
- Where such publication is made in connection with any company prospectus or similar document.
- Where the client has notice that NEL is seeking or intends to seek patent or like protection for any intellectual property produced in the course of rendering the services.

3 NEL services are provided subject to terms and conditions acknowledged by our commercial staff and the applicable scope stated in the ISO 9001 certification and/or ISO 17025 accreditation. Services which fall outside the applicable scope of ISO certification and/or accreditation will be stated in this report.

Contact

For further information about the work contained in this report, please contact:
Dr Martin Hanton
TÜV SÜD National Engineering Laboratory
East Kilbride
Glasgow
G75 0QF
Email: martin.hanton@tuv-sud.co.uk
Tel: +44 (0) 1355 593700
web: www.tuv-sud.co.uk/nel

Revision History

Revision	Date	Description	Author(s)	Approved By

Report Production

	Name of Responsible Person(s)	Signature
Contributor(s)	Sarah Jones	
Author(s)	Claire Forsyth	
Technical Peer Review by	Craig Marshall	
Approved by	Carl Wordsworth	

EXECUTIVE SUMMARY

Multiphase flow meters (MPFMs) are being used increasingly across the offshore oil industry both due to increased confidence in their accuracy and because the flows either cannot be separated to measure the fluid flows individually or it is not economically feasible to do so.

At present, common practice for validating an MPFM prior to installation is with a Factory Acceptance Test (FAT) at a multiphase flow facility. The FAT test conditions may not cover the entire expected operational range of the device, the test fluids may not be the same as the meter will see in service and the tests are likely to be carried out at a lower pressure.

Removal of an MPFM for calibration may require a production shutdown and is particularly difficult and expensive where the meter is installed subsea. Since both removal for calibration and direct comparison are often not feasible, the ideal solution would be to provide *in situ* verification of the meter output to give confidence that an MPFM is operating correctly. The measurement principles behind MPFMs are highly dependent on fluid physical properties. Developing reliable ways to measure fundamental fluid properties *in situ* in real time, or close to it, therefore appears to be a requirement for the development of *in situ* verification methods for MPFMs, particularly where the composition of the produced fluids changes over the life of the well.

This report focuses on the potential for commercially available single phase physical property sensors suitable for subsea deployment to be used in multiphase flows. The specific objectives of this work package were to:

- Investigate the key fluid properties required for multiphase flow measurement
- Review commercially available inline physical property sensors
- Determine the most suitable inline physical property sensors for testing
- Assess the performance of the selected fluid property sensors across a range of multiphase flow conditions

Overall, none of the sensors tested appear suitable for accurate fluid property measurements in multiphase flows with high gas volume fraction (GVF) being present at the sensor location. This was expected since none of the sensors tested are designed for gas/liquid flows. However, all sensors performed reasonably well under liquid only test conditions.

These sensors have the potential to be used in low GVF flows if mounted in a suitable location and coupled with a tomography system to confirm whether the sensor is fully submerged in the liquid phases and therefore when their output can be relied on.

There could be merit in additional research to test sensors in conjunction with a tomography system to show the phase distribution at the sensor location, combined with working with manufacturers on the instrument outputs. This could result in a sufficiently accurate system for field use with an assessment of how the level of uncertainty varies with GVF.

The availability and performance of commercially available sensors with potential should continue to be regularly reviewed.

TABLE OF CONTENTS

Page No

ABBREVIATIONS

CFD	Computational Fluid Dynamics
E&H	Endress & Hauser
ECT	Electrical capacitance tomography
ERT	Electrical resistance tomography
FAT	Factory acceptance test
GVF	Gas volume fraction
MEMS	Microelectromechanical systems
MPFM	Multiphase flow meter
NEL	TUV SUD National Engineering Laboratory
UKAS	United Kingdom Accreditation Service

1 INTRODUCTION

1.1 Background

Multiphase flow meters (MPFMs) are being used increasingly across the offshore oil industry both due to increased confidence in their accuracy and because the flows either cannot be separated to measure the fluid flows individually or it is not economically feasible to do so.

Subsea MPFMs are usually installed on remote wells and used as allocation meters to determine the flows from each of a number of wells, which may be owned by different operators, tied back to an offshore platform. MPFMs are also installed topside to measure the combined well flows.

At present, common practice for validating an MPFM prior to installation is with a Factory Acceptance Test (FAT) at a multiphase flow facility. The range of test conditions during the FAT may not cover the entire expected operational range of the device. In particular, the test fluids may not be the same as the meter will see in service and the tests are likely to be carried out at a lower pressure.

For topside meters, where the platform has a test separator, an MPFM's measurements can be compared with the results from a well test to provide an *in situ* meter calibration with the actual produced fluids. Since test separators are not always installed on offshore platforms another option would be for an MPFM to be compared to another MPFM. Due to their cost, as well as topside space and weight constraints, it is not usual to have a standby meter. Removal of the meter for calibration may therefore require a production shutdown.

Calibration is even more challenging for subsea MPFMs as access to subsea installations is difficult and expensive. Since one of their key roles is as an allocation meter, removal for calibration at one of the multiphase flow facilities located around the world will almost inevitably require a lengthy shutdown of the well as there will be no other means of measuring the flows from the well. Apart from any risk of hydrate formation and the costs of required dosing during the shutdown, there will be a significant loss of revenue while the meter is unavailable.

Direct comparison with a topside MPFM or other comparable method is unlikely to be a viable option as this method would measure the combined flows from all remote wells so a direct comparison would require other remote wells to be shut in. The shutdown period of the other wells will depend on where the tiebacks combine and the length of any common pipelines.

Another option for subsea MPFMs is the 'by difference' method where only the well with the MPFM requiring verification is shut in and the flow deduced from the difference between the total flows before and after the well was shut in. For the most accurate results, the flows should be run through single phase meters downstream of a test separator (if available). This should not require an extended shutdown period.

Since both removal for calibration and direct comparison are often not feasible, the ideal solution would be to provide *in situ* verification of the meter output to give confidence that a MPFM is operating correctly. The measurement principles behind MPFMs are highly dependent on fluid physical properties. Developing reliable ways to measure fundamental fluid properties *in situ* in real time, or close to it, therefore appears to be a requirement for the development of *in situ* verification methods for MPFMs, particularly where the composition of the produced fluids changes over the life of the well.

Several commercially available instruments for the measurement of fluid properties are already suited for use at the pressures and temperatures likely to be experienced subsea but all are designed for use in single phase flow.

1.2 Scope of work

This report focuses on the potential for commercially available single phase physical property sensors suitable for subsea deployment to be used in multiphase flows. The specific objectives of this work package were to:

- Investigate the key fluid properties required for multiphase flow measurement
- Review commercially available inline physical property sensors
- Determine the most suitable inline physical property sensors for testing
- Assess the performance of the selected fluid property sensors across a range of multiphase flow conditions

1.3 About NEL

TUV SUD National Engineering Laboratory (NEL) is an independent industrial research establishment specialising in flow meter calibration, test work, research and development, product evaluation and technical consultancy, with specific expertise in the oil, gas and process sectors. NEL is the holder of the UK National Standards for flow, density and multiphase flow measurement. Facilities exist for calibration and research involving water, oil, gas, and multiphase flow measurement devices. The facilities are fully traceable to Primary National Standards and accredited by the United Kingdom Accreditation Service (UKAS).

In the area of flow measurement, NEL has internationally recognised expertise and extensive project experience stretching back more than 50 years and counts many of the world's leading oil & gas operators and service companies among its clients. Consultancy work is carried out in a wide range of fields including:

- Multiphase and wet-gas metering applications
- Computational Fluid Dynamic (CFD) modelling of fluid flow and erosion (single and multiphase)
- Uncertainty analysis of custody transfer and allocation metering systems
- Meter technology selection for a range of applications
- Meter system design and installation guidance.

2 MULTIPHASE METERING TECHNIQUES

2.1 General

Commercial MPFMs employ several instrumentation techniques to measure different aspects of the flow. The measurements are then combined and analysed to give individual phase flowrates.

Although manufacturers each have their own proprietary meter designs, there are some commonly used measurement techniques which follow similar principles:

- Measure the bulk flow rate of the multiphase mixture
- Measure the fluid properties (or use provided values)
- Measure or calculate the individual phase fractions
- Use this information to calculate individual component flow rates.

An overview of the technologies relevant to this project is given below. A more comprehensive description can be found in [1].

2.2 Bulk Flow Rate Measurement

Various methods can be used to measure the bulk flow rate through a multiphase mixture.

2.2.1 Differential Pressure Meters

The principle of a differential pressure meter is to place an obstruction in the flow and measure the differential pressure across it which is then used to calculate the flow rate. In theory, any restriction in the flow can be used if a repeatable, reproducible and measurable pressure drop is produced. The choice of the primary element may depend on the flow conditions expected in the pipeline, e.g. orifice, cone and wedge meters are more commonly used for wet gas.

The majority of commercial multiphase meters use a Venturi meter (Figure 1) as part of their technology. This is largely due to their comparatively low pressure drop, their resistance to erosion (compared to orifice plates) and their most robust instrumentation requirement in terms of uncertainty (a single differential pressure measurement) [2]. They are generally mounted downstream of a blind tee to keep the fluids well mixed so as to reduce the effects of flow regime on measurement uncertainty.

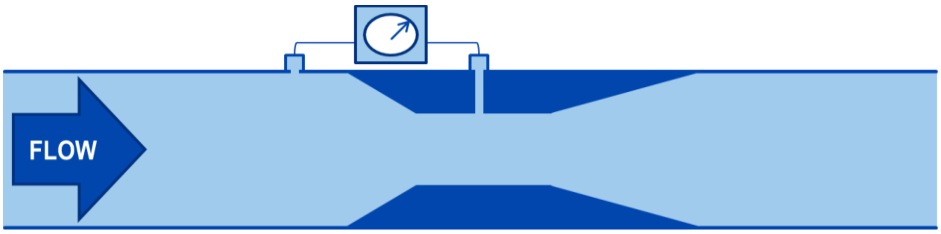


Figure 1– Venturi meter measurement principle

If a Venturi meter is used for measuring bulk flow rate, a separate density measurement is required. If the bulk flow rate is already known, a Venturi meter can be used to determine the fluid density [3]. A measurement of viscosity is necessary if Reynolds number is required.

2.2.2 Cross-Correlation

Cross-correlation compares the time histories from two or more sensors placed a known axial distance apart (Figure 2).

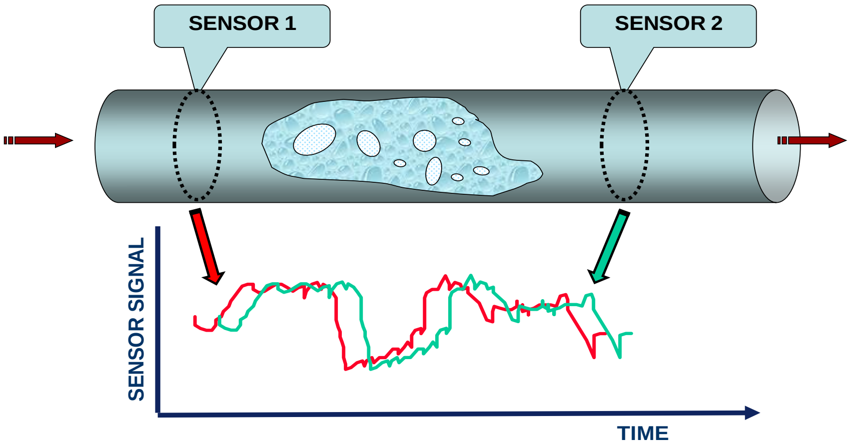


Figure 2– Cross-correlation method

The signal processing looks for matching signals with a time delay due to flow disturbances such as turbulence and vortices in single phase flows and slugs and bubbles in multiphase flows. The time difference from the disturbance being detected at the upstream and downstream sensors, along with the known distance between the sensors, allows the mean flow velocity to be calculated, allowing the bulk flow rate to be determined [2].

Various sensor types can be used including: capacitance sensors, conductance sensors, densitometers and pressure gauges. Key fluid properties for this technology therefore include: capacitance, conductance and density.

Capacitance sensors will not measure accurately at high water-cuts and the opposite is true for conductance sensors. A combination of both types of sensor is normally used to allow the cross-correlation technique to be used in both oil continuous and water continuous flow.

Benefits of cross correlation include high turndown, generally non-intrusive and it can be used to infer flow regimes. In common with other technologies it also requires semi-empirical (and flow regime dependent) slip models to correct for liquid/gas velocity differentials.

A major disadvantage of the cross-correlation method is that it is flow regime dependent, in some cases it will not be possible to detect a characteristic flow disturbance at both sensor locations, for example with homogeneous or smooth stratified flow. For this reason, cross correlation is not used on its own to determine bulk flow rate but is commonly used to verify the output of the Venturi meter in commercial MPFMs [4].

2.2.3 Coriolis Meters

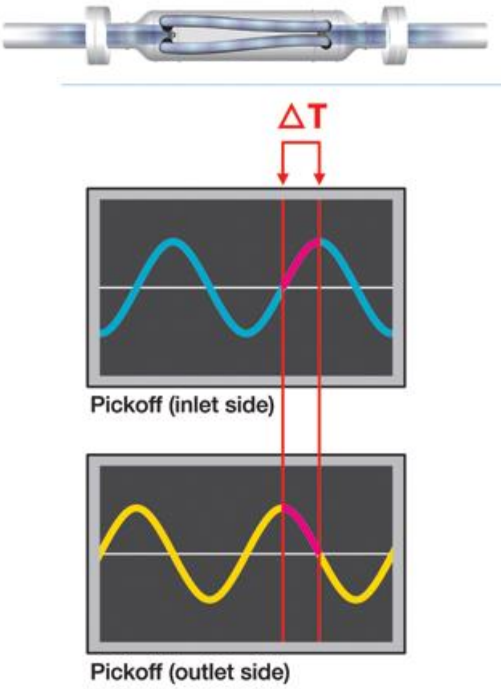


Figure 3– Coriolis phase shift

Coriolis meters allow mass flow rate to be measured directly and also allow fluid density to be determined. Their measurements can be affected by pressure and temperature and may therefore require manufacturer corrections. They are also affected by viscosity but to a lesser extent [2].

The measuring principle for Coriolis meters is based on the Coriolis effect (Figure 3). In these meters, measuring tubes containing flowing fluid are oscillated at their resonant frequency. As fluid flows through the tubes, there is a phase shift or deflection between inlet and outlet sections (which is measured by pickoff sensors), and this shift can be used to determine the mass flow rate. The density measurement is derived from the resonant frequency of oscillation of the tubes. Coriolis meters are available with various tube configurations, twin U-shaped tube designs are very common, but there are also single tube designs, straight, triangular and S-shaped tubes and more.

Coriolis flow meters are widely utilised in the oil and gas sector for fiscal and custody transfer metering of liquids. They have not traditionally been used in used in high accuracy gas metering because their performance is generally poorer in low density fluids. The accuracy in gas has been improved recently and manufacturers are starting to offer Coriolis meters for custody transfer metering in gases.

The accuracy in multiphase flows is influenced by the fractions and distribution of each phase. Large errors can occur when separated gas or liquid collect at high or low points in the meter, or even when there is different fluid composition in each measuring tube. This can be avoided by using a meter based on a single, straight tube design. Their use in gas/liquid multiphase flows is under development, and they are increasingly being used as a component in MPFMs.

2.2.4 Positive Displacement Meters

Positive displacement meters measure the volumetric flow rate of a fluid by separating it into discrete measures of known volume and then counting the measures. Oval gear devices are the most common type of positive displacement meter in multiphase meters. Rotating scroll devices can also be used. If mass flow rate is required, the mixture density also needs to be measured [4].

2.3 Phase Fraction Measurement

Various phase fraction measurement methods exist to determine the fraction of the pipe cross-section taken up by each phase within the multiphase flow.

2.3.1 Gamma ray absorption (electromagnetic)

With gamma ray absorption, the absorption of gamma rays (from a nuclear source) by the fluid is used to determine the composition of the bulk fluid. A nuclear source is placed at one side of a pipe with a detector at the opposite side. The number of rays that are able to pass through the fluid is dependent on the fluid's density: gas is a weaker absorber than oil and water due to its much lower density.

Two main types of gamma ray attenuation are used in MPFMs: single energy and dual energy. With single energy attenuation, high energy gamma rays are emitted by a nuclear source. With these rays, absorption is proportional to the fluid density only. This allows the relative proportions of gas and liquid (void fraction) along the beam's path to be determined since gas transmits substantially more rays than liquid. The disadvantage of single energy attenuation is that it cannot clearly distinguish between the oil and water phases since oil and water both have similar transmission properties (Figure 4).

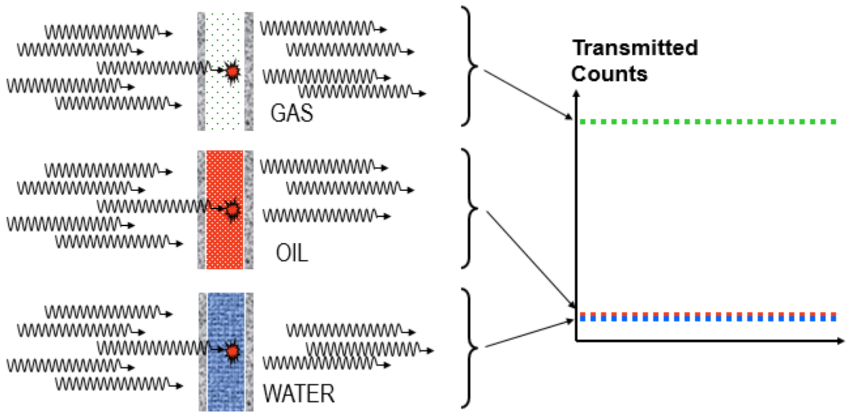


Figure 4 – High energy gamma ray attenuation

Dual energy attenuation makes use of a high energy source as mentioned above, but also makes use of a low energy source. With low energy rays, absorption is proportional to both fluid density and fluid type (e.g. hydrocarbon, fresh water, salt water). This allows the individual oil and water components to be determined (and hence water cut) as shown in Figure 5.

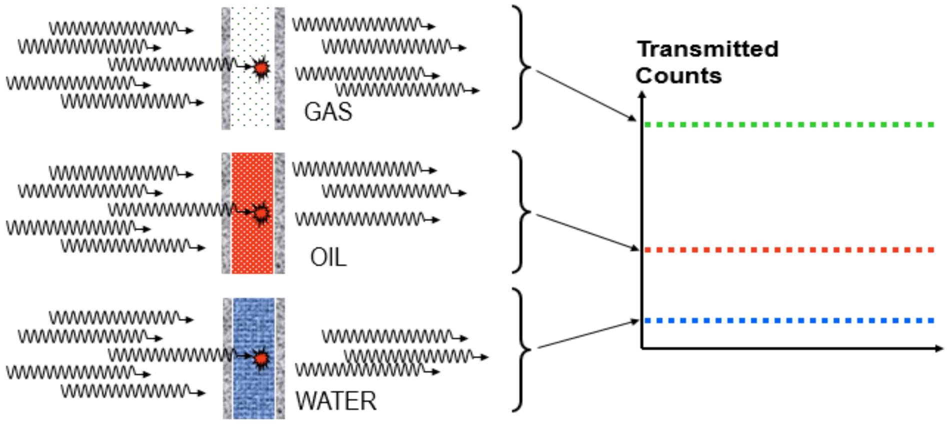


Figure 5 – Low energy gamma ray attenuation

Using both a high and low energy source (dual energy attenuation) therefore allows the phase fraction of each individual component (oil/water/gas) to be determined. This technique requires information on the water salinity as gamma ray absorption is sensitive to this. If the salinity is constant the value can be inputted manually otherwise an additional conductivity sensor is required.

2.3.2 Electrical Properties

Methods in this category measure bulk electrical properties of the fluid, such as capacitance and conductivity, to determine the composition of the bulk fluid. The very different electrical properties of oil, water and gas can be used to determine phase information. For example, water is conductive and has a much higher relative permittivity than oil and oil is non-conductive and has a higher relative permittivity than gas. Both sensor types require calibration with the process fluids. Conductivity measurements are sensitive to water salinity and capacitance measurements are sensitive to permittivity.

<u>Capacitance</u>

For capacitance based systems, two or more electrodes are embedded in the pipe wall (but do not need to be in contact with the fluid) and used to measure the fluid's relative permittivity (dielectric constant). This permittivity value depends on fluid composition and can therefore be used to determine the fluid's water cut, but only for low water cuts due to the very high permittivity of water in comparison with oil or gas. To allow the full water cut range to be covered, capacitance sensors are normally used in combination with conductivity sensors. Often a separate density measurement is used to allow all three phase fractions to be deduced [2].

Electrical capacitance tomography (ECT) uses an array of sensors around the pipe to measure the permittivity of the fluid between pairs of sensors in sequence. This information is used to construct an image of the phase distribution across a cross-section of pipe. Again, this technique can only be used for low water cuts and works best for oil and gas flows.

<u>Conductivity</u>

Conductivity is measured by putting a voltage across a pair of electrodes and measuring the current which depends on the fluid conductivity. Again, a separate density measurement is often used to allow all three phase fractions to be deduced [2].

Conductivity methods only work for water-continuous flows. As the water cut decreases below the inversion region, the fluid becomes oil-continuous and therefore electrically insulating. As both oil and gas are non-conductive, the method cannot distinguish between them. Electrical resistance tomography (ERT) has an array of sensors around the pipe in contact with the fluid.

The technique involves inputting a pre-determined electrical current into the flow and measuring the voltage between pairs of electrodes (or vice versa) in sequence. The magnitude of the voltage (or current) depends on the fluid conductivity. As with ECT these measurements are used to reconstruct an image of the phase distribution across the pipe cross-section. This technique is slightly more limited than ECT as it cannot detect conductive fluid structures isolated by non-conductive fluid.

2.4 Microwaves (electromagnetic)

Microwave methods, which exploit the difference between the conductivity and permittivity of water and oil, are used in commercially available water cut meters. They are suitable for the full water cut range.

There are two main microwave techniques: resonance and attenuation.

Resonance

With this technique, electromagnetic waves in the microwave spectrum are introduced into a resonant cavity. At the resonant frequency, the reflected waves interfere constructively, forming a standing wave pattern within the cavity. The frequency at which the cavity resonates depends upon its physical dimensions and the permittivity (dielectric constant) of the material inside the cavity [4].

The resonant frequency of the cavity therefore alters with changes in the fluid permittivity. The width of the resonant peak is related to the conductivity of the fluid in the cavity. These measurements allow the fluid composition to be calculated. If used with a separate density measurement, the phase fractions of all three components can be determined.

Attenuation

Microwave attenuation systems generally involve an electromagnetic oscillator (microwave generator) plus transmitting and receiving antennae. Measurements of the attenuation and phase shift of the microwaves (which depend on bulk fluid properties including the water salinity, oil density and mixture temperature) are used to determine the water fraction.

3 KEY FLUID PROPERTIES FOR MULTIPHASE METERING

3.1 General

Fluid properties play a crucial role in multiphase flow measurement and the relative importance of a particular fluid property depends on which flow measurement technology is in use. As a result, methods of determining fluid properties accurately and efficiently are of great interest. At present, sampling is often relied on to determine fluid properties but this is time consuming, there is a time delay between taking the sample and the result being available and samples taken may not be representative of the bulk flow. In addition, regular sampling needs to be carried out if the fluid properties change over time which is particularly difficult for subsea MPFMs. Techniques for determining fluid properties *in situ* and in real time are therefore of considerable interest.

The techniques outlined in Section 2 are not sufficient to measure individual component flow rates alone, and so a combination must be used.

3.2 Identified Key Fluid Properties

Based on the review of bulk flow rate and phase fraction measurement methods, the most important fluid properties for multiphase flow measurement are:

- Density
- Viscosity
- Conductivity (from which salinity can be calculated)
- Capacitance (relative permittivity giving dielectric constant).

Table 1 summarises the findings of Section 2 and demonstrates that fluid density is a key requirement for most of the techniques. Blue indicates a reliance on this physical property for the respective technique.

Table 1 – Summary of key fluid properties for multiphase flow measurement

Technique	Density	Viscosity	Capacitance	Conductivity / salinity
Differential pressure	■	■		
Cross-correlation	■		■	■
Coriolis	■	■		
Positive displacement	■			
Gamma ray absorption				■
Electrical	■		■	■
Microwave	■			■

3.3 Example Technology Information from Manufacturers

A brief review of manufacturers' information on the various technologies is summarised in Table 2. This highlighted the fluid property requirements of commercial MPFMs. Blue indicates this technology was used by the manufacturer.

Table 2 – Commercial MPFM technologies

Manufacturer & meter(s)	Technologies involved							
	Differential pressure	Cross-correlation	Coriolis	Positive displacement	Gamma ray absorption	Electrical	Microwave	Other
Agar, MPFM- 50 SERIES [5]	■		■			■	■	
Emerson, Roxar Multiphase, Roxar Subsea Multiphase [6]	■	■			■	■		
Emerson, Roxar Water Cut Meter [7]							■	
Weatherford, Alpha V/SR [8]								Sonar-based bulk-velocity measurements
Weatherford, Alpha VSRD [8]	■				■			Sonar flow meter Red Eye® MP water-cut meter
FMC, MPM [9]	■				■	■		'3D broadband' tomography system
ABB, VIS (VEGA Isokinetic Sampling) Multiphase Meter [10]								Isokinetic sampling. Involves the withdrawal of a small fraction of the stream and its subsequent separation
Schlumberger, Vx Multiphase Meter [11]	■				■			
Pietro Fiorentini, Flowatch Multiphase Meter [12]	■	■			■	■		Additional optional sensors: NIR (near infra-red) water cut sensor, Flow velocity module using local turbulence pressure measurements
M-Flow, Various [13]	■		■		■	■		
Abbon, Abbon 3PM [14]	■					■		
Expro, Sonar Monitor [15]	■					■		Sonar technology
Solartron, Dualstream [16]	■							For wet gas: dual DP measurements
Neftemer, Neftemer multiphase meter [17]	■				■			

4 IN SITU SENSOR TECHNOLOGIES FOR MEASURING FLUID PROPERTIES

4.1 Overview

A literature review was carried out to establish the range of available techniques for *in situ* measurement of fluid properties. Many of the more novel methods (e.g. MEMS, microelectromechanical systems) appear to still be at the research stage. Several *in situ* commercially available fluid property technologies that could be suitable for this work.

For subsea applications, technologies suitable for pressures in excess of 100 bar will be required. In this report, sensors have therefore been split into two categories based on their pressure rating: 'subsea ready' and 'non-subsea ready'.

4.2 Expected Uncertainties

An initial review of literature suggests that the following uncertainties are likely estimates for measuring fluid properties *in situ* in multiphase flows (Table 3):

Table 3 – Expected fluid property uncertainties in multiphase flows (N.B. no confidence levels given)

Property	Uncertainty	References
Density	0.5-3%	[18] [19] [20]
Viscosity	At best 5-10% Up to 40 %	[18] [19] [21]
Conductivity/ Salinity	0.5 S/m 1%-10%	[22] [23] [24]
Capacitance/ Relative permittivity (dielectric constant)	5%-10%	[23] [25] [26]

4.3 Density and Viscosity Measurements

An initial literature review of technologies found only two sensor systems that appeared suitable and 'industry ready' for measuring density and viscosity *in situ* at high pressures (>100 barg) and could be added to a subsea installation.

Both work on similar principles, making use of resonant frequency and damping measurements to measure fluid density and viscosity respectively.

Schlumberger's InSitu density and viscosity sensor can be used to measure both density and viscosity at reservoir conditions in real time. The device contains a vibrating sensor that oscillates in two perpendicular modes within the fluid. The resonant frequency of the sensor is related to the flowing liquid's density and its damping is related to the fluid viscosity. Dual mode oscillation is used as it minimises the effects of temperature and pressure on the sensor through common mode rejection [27] [28].

Rheonics has a range of sensors that work on similar principles, with resonant frequency and damping being used to determine fluid density and viscosity respectively (Figure 6) [29] [30].

Both sensors' features are summarised in Table 4.

Figure 6– Rheonics SRD Sensor

Other commercial systems exist but are not suitable for the pressures of over 100 bar often experienced subsea. For example, Endress & Hauser's Truedyne system is available to measure density, but the maximum operating pressure is 20 bar. Similarly, AveniSense, VAF Instruments, Centec/Rhotec and Parker have sensor based technologies to measure fluid density and viscosity, but their maximum operating pressures are in the region of 20 to 40 bar.

A summary of non-subsea ready sensors is given in Table 5. These make use of similar principles to the subsea ready sensors.

The E&H TrueDyne sensor is shown in Figure 7. Fluid is passed through the sensor microchannel which vibrates. The resulting natural frequency of the microchannel is dependent upon the mass and therefore the density of the fluid in the micro channel [31].

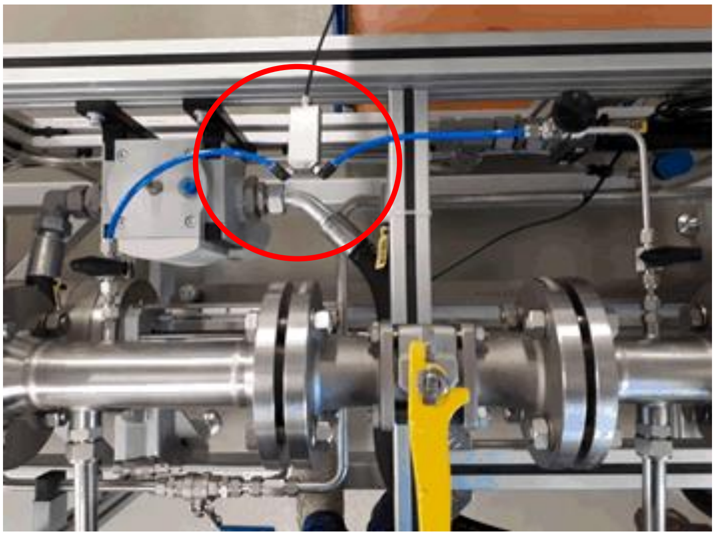


Figure 7– E&H TrueDyne sensor installation [32]

The AveniSense Devil sensor is shown in Figure 8. Its measurement principle is based on a resonating element with the resonant frequency dependent on the fluid density.

Figure 8– AveniSense Devil Sensor [33]

The VAF Viscosense sensor is show in Figure 9. Its measuring principle is based on the torsional vibration (piezo-driven) of a pendulum in the fluid. The frequency and damping of this vibration are directly related to the density and viscosity respectively [34].

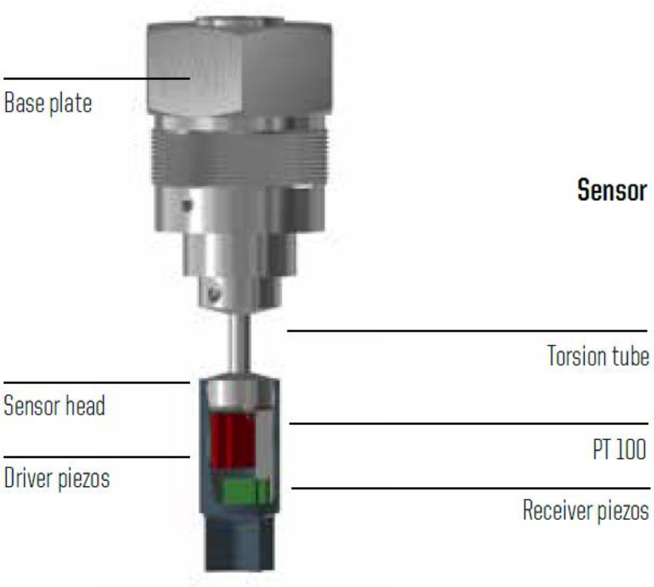


Figure 9– VAF Viscosense Sensor [34]

The Centec Rhotec sensor is show in Figure 10. With this sensor, fluid is passed through an oscillating u-tube. The resonant frequency depends on the fluid density which allows the density to be determined.

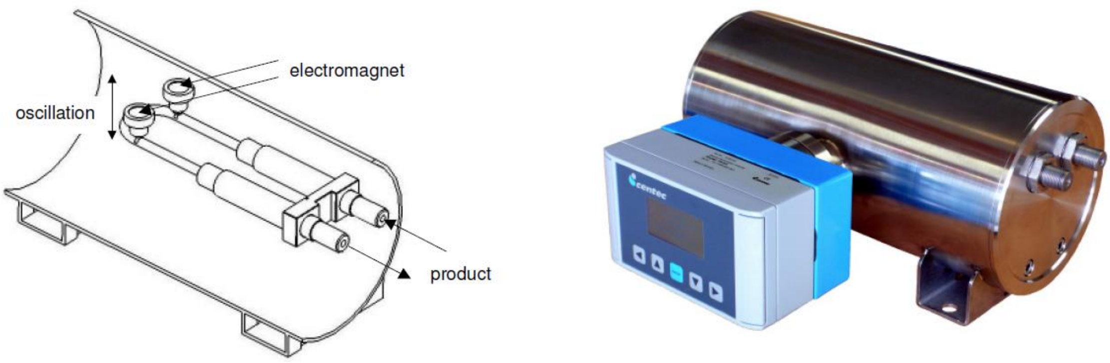


Figure 10– Centec Rhotec Sensor [35]

The Parker FPS2000 sensor which uses tuning fork technology to determine fluid density and viscosity is shown in Figure 11. Although not explicitly stated, it is assumed to use a similar measuring principle to the sensors previously discussed.

Figure 11– Parker FPS2000 Sensor [36]

In addition to the commercial systems mentioned, there are a number of papers (largely academic) on *in situ* density and viscosity sensor based measurement methods that are not yet ready for industrial use. Those reviewed have not been tested at the pressures required for this work and will be investigated in a separate work package.

Table 4 – Density and viscosity sensors for subsea applications (>100 bar)

Company/Product	Properties Measured	Technique	Pressure limit	Temperature limits	Density range and uncertainty	Viscosity range and uncertainty
Schlumberger InSitu Density InSitu Viscosity [20] [27] [28] [37] [38]	Density Viscosity	Miniaturised sensor (MEMS based) Resonant frequency used for density Damping used for viscosity	< 1720 bar	< 190 °C	Density 50-1200 kg/m^3 ±12 kg/m^3 (±1-24 %)	0.2-50 cP 0.2-300 cP for high viscosity system (measures viscosity only) ±10-12 %
Rheonics DVM/DVP/SRV/SRD Sensors [39] [40] [41] [42]	Density Viscosity	Torsional resonator Resonant frequency used for density Damping used for viscosity Flow through and probe versions available	Flow through version < 2100 bar Probe version < 700 bar Extended viscosity version < 350 bar	-40 to 200 °C	< 1500 kg/m^3 ±1 kg/m^3	0.2-300 cP ±0.1 cP below 1cP Otherwise ±5 % Extended viscosity version 3-10000 cP ±5 % across range

Table 5 – Density and viscosity sensors for non-subsea applications

Company/Product	Properties Measured	Technique	Pressure limit	Temperature limits	Density range and uncertainty	Viscosity range and uncertainty
E&H TrueDyne TrueDyne Density Module [31]	Density	Micro channel filled with fluid Natural frequency of micro channel is dependent upon the mass and therefore density of the medium	< 20 bar	-20 to 60 °C	600-1000 kg/m^3 ±0.5 kg/m^3	n/a
AveniSense Devil [33]	Density Viscosity	Resonating micro paddle	< 40 bar	-40 to 85 °C	650-1350 kg/m^3 ±4.5 kg/m^3	0.3-100 cP ±2 % of full scale
VAF ViscoSense 3D [34]	Density Viscosity	Torsional vibration of a piezo-driven pendulum in liquid Damping is directly related to viscosity Frequency is related to density	< 40 bar	0 to 200 °C	750-1100 kg/m^3 ±1 kg/m^3 or 0.1 %	0-50 cP ±2 % or 0.5 cP
Centec Rhotec [43]	Density	Liquid flows through a thin U-shaped tube inside the sensor which is excited to oscillate at the resonant frequency. This frequency depends on the fluid density.	< 50 bar	-25 to 125 °C	0-3000 kg/m^3 ± 0.1 kg/m^3	n/a
Parker FPS2000 [36]	Density Viscosity Also mentions dielectric constant measurements	Uses tuning fork technology	< 25 bar	-40 to 150 °C	650-1500 kg/m^3 ±3 %	0.5-50 cP ±5 % (accuracy)

4.4 Conductivity and Capacitance Measurements

The literature search found few conductivity/capacitance sensors that were rated for high pressures (>100 bar) and that would therefore be potential candidates for subsea installation. The two sensors that appeared suitable (from Emerson and CMR) are summarised in Table 6.

CMR's conductivity/salinity sensor is shown in Figure 12. Limited information was available about the operating principles of both the CMR and the Emerson sensors.

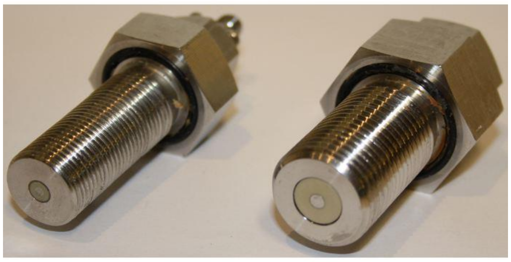


Figure 12– CMR Conductivity/Salinity Sensor [44]

Various standard conductivity sensors exist (Table 7) that are rated for lower pressures. There are two techniques for measuring conductivity: contacting and inductive

<u>Contacting</u>

With contacting conductivity sensors, an alternating voltage is applied to the electrodes and the resulting current is measured. Ohm's law is used to calculate the resistance of the fluid, which allows conductance to be determined since it is the reciprocal of resistance.

<u>Inductive</u>

Inductive conductivity sensors (also known as toroidal or electrodeless) consist of two wire-wound metal toroids encased in a plastic body (Figure 13). One toroid is the drive coil and the other is the receive coil. An alternating voltage is applied to the drive coil and this induces a voltage in the fluid surrounding the coil. This voltage causes an ionic current to flow that induces an electric current in the receive coil, which is measured. This induced current is directly proportional to the conductivity of the solution.

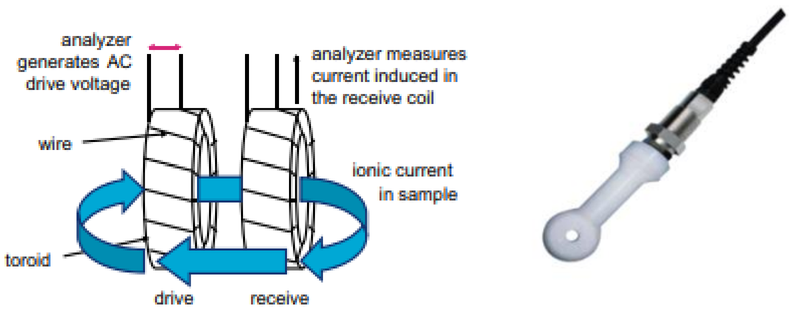


Figure 13– Inductive conductivity sensor measurement principle and example sensor [45] [46]

Table 6 – Conductivity/capacitance sensors for subsea applications (>100 bar)

Company/Product	Properties Measured	Technique	Pressure limit	Temperature limits	Operating Conditions	Uncertainty
Emerson Roxar Multiphase Salinity System [22]	Conductivity (and salinity)	Microwave technology	< 350 bar	-20 to 130 °C	Water transition point to 100% WLR	0.5 S/m (0.5% for salinity)
CMR Salinity and Water-Liquid Ratio Sensor (high frequency EM) [44]	Conductivity (and salinity) Water Liquid Ratio Permittivity	High-frequency electromagnetic sensor	'Tested in high pressure flow loops'	No information	Designed for multiphase and wet gas flows	No information

Table 7 – Conductivity sensors for non-subsea applications

Company/Product	Properties Measured	Technique	Pressure limit	Temperature limits	Operating Conditions	Uncertainty
Yokogawa - various models: Inductive (Torodial, Electrodeless) Conductivity Sensor ISC40 2-electrode conductivity sensor (and analyser/transmitter e.g. Inductive Conductivity Converter ISC450) [47] [48] [49] [50] [45]	Conductivity	Contacting and inductive	< 20 bar	-20 to 130 °C	Conductivity range 1 µS/cm to 2 S/cm (All data based on ISC40 sensor)	0.5% ± 0.5 µS/cm
Honeywell - various models: 5000TC Toroidal (electrodeless) conductivity sensor 4905 series (and analyser/transmitter e.g. APT2000) [51] [52]	Conductivity	Contacting and inductive (see below)	< 14 bar	-10 to 125 °C	Conductivity range 0.2 mS/cm to 2 S/cm (All data based on 5000TC sensor)	1 % ± 0.02 mS/cm
Emerson - various models: Rosemount 228 Toroidal conductivity sensor Rosemount 400 (and analyser/ transmitter e.g. Rosemount 1056) [53] [54]	Conductivity	Contacting and inductive (see below)	< 20 bar	< 200 °C	< 2 S/cm (All data based on Rosemount 228 sensor)	1 % ± 10 µS/cm

5 FEEDBACK FROM MANUFACTURERS

5.1 General

The manufacturers in Table 4 to Table 7 were contacted for more information about their sensor operation with a view to acquiring the sensors for performance testing at NEL in multiphase flows. The main issues discussed with the manufacturers were:

- Velocity/flow rate limitations
- Pressure rating
- Ease of integration into a pipeline
- Suitability for use with gas
- Availability.

5.2 Density and Viscosity Measurements

5.2.1 Rheonics DVP Sensor

The Rheonics DVP sensor appears to be the most suitable of the density and viscosity sensors for this application. This sensor is inserted into the pipeline through a threaded boss and provides continuous density and viscosity measurements. It has various pressure models available (up to 700 bar).

The sensor has been tested for liquid velocities up to 7 m/s in small diameter pipe and 4 m/s in 4 inch pipe and was expected to be suitable for the liquid velocities in the test programme (up to around 5 m/s). Rheonics suggested that expected gas velocities (up to 30 m/s) should not be an issue unless they result in very strong vibrations, although they did express concern about bubbles of gas in the flow and specifically how the bubbles would interfere with the measurement principle.

The manufacturer has limited experience of the sensor with multiphase flows but said some customers have used it under these conditions.

5.2.2 Schlumberger InSitu Density and InSitu Viscosity

Although initially appearing suitable, discussion with Schlumberger suggested otherwise. The system is only suitable for low flow rates and would therefore require a bypass which would introduce the issue of the bypass fluid not being representative of the bulk flow. The product was also not ready to ‘plug’ into existing pipework and requires considerable specialist equipment.

5.2.3 E&H TrueDyne, AveniSense Devil, VAF ViscoSense 3D and Centec Rhotec

These systems are only suitable for low fluid velocities (lower than those that will be used for testing). Although VAF and AveniSense sensors are suitable for direct installation into a pipe system, the flow rates/velocities experienced in the test programme were too high.

These sensors would therefore require a bypass which would introduce the issue of the bypass fluid not being representative of the bulk flow.

5.2.4 Parker FPS2000

While the sensor appeared suitable for the test liquid velocities, further information suggested it is suitable for oil only flows and is therefore not suitable for multiphase fluids.

5.3 Conductivity and Capacitance Measurements

5.3.1 Emerson Roxar Multiphase Salinity System

It was decided not to pursue this system further as it was already an advanced system (designed for addition onto existing or new multiphase meters) and would be outside the scope of the project.

5.3.2 CMR Salinity and Water-Liquid Ratio Sensor

This system was not commercially available but CMR indicated that it could be used for research purposes in high pressure gas loops for oil/water/gas multiphase flows.

5.3.3 Yokogawa Inductive Sensor

Yokogawa indicated that their Inductive (Toroidal, Electrodeless) Conductivity Sensor ISC40 and transmitter/analyser (ISC450) could be suitable as a low pressure option. They suggested that the sensor would be suitable for the test liquid velocities of up to 5 m/s. They have no gas velocity data but know that the torque at breaking point is approximately 100 Nm. This suggested that the sensor would be suitable for the gas velocities in the test programme. The sensor can be threaded into a standard pipe fitting but is only suitable for up to 10 barg. A flanged connection with a higher pressure rating was also available that is more appropriate for NEL's multiphase test facility.

6 FINAL CANDIDATE SELECTION

Sensor technologies that are designed to measure water cut were excluded from the final selection as being outside the scope of this project.

For density and viscosity measurements, the Rheonics DVP sensor was chosen. This was due to its apparent suitability and the elimination of all other density/viscosity sensors due to velocity limitations. For the initial trials in NEL's multiphase test facility, the lower pressure model (suitable for up to 70 bar) will be used.

For conductivity measurements, Yokogawa's Inductive (Toroidal, Electrodeless) Conductivity Sensor ISC40 and transmitter/analyser (ISC450) was chosen (flanged connection). Although not suitable for pressures above 20 bar, it was still suitable for the initial trials in NEL's multiphase test facility.

It should be noted that none of these sensors is designed for gas/liquid multiphase mixtures. The Rheonics density and viscosity sensors were classified as 'subsea ready' since they are rated for typical subsea pressures and temperatures. The Yokogawa conductivity sensor is rated for lower pressures and is therefore not 'subsea ready'.

6.1 Rheonics Density and Viscosity Sensors

Figure 14– Rheonics SRD (left) and DVP (right) sensors

The Rheonics SRD and DVP sensors work on similar principles, with resonant frequency and damping used to determine the fluid density and viscosity respectively, as described in 4.3 above (Figure 14).

It should be noted that if the fluid contains particles, droplets or other contaminants which will be deposited onto the sensor, the sensor head will require regular removal and cleaning to maintain an accurate reading. In particular, the DVP sensor is not suitable if magnetic particles are present in the fluid.

The DVP sensor has higher accuracy claims than the SRD sensor and was recommended over the SRD by the manufacturer. The SRD was proposed as a secondary choice if the DVP proved unsuitable. It was decided to test both sensors.

The sensors tested were suitable for pressures up to 70 bar. Higher pressure models are available: the SRD model is available for pressures up to 350 bar and the DVP model for up to 700 bar. Performance claims of the sensors are summarised in Table 8. The most significant difference between the sensors is the viscosity range with the SRD being capable of measuring much higher viscosities than the DVP.

Table 8 – Rheonics sensors performance claims [30] [55]

Property	SRD	DVP
Material of wetted parts	316L	Titanium Grade 5
Temperature measurement	Pt1000 (DIN EN 60751 Class B)	Pt1000 (class AA)
Surrounding fluid minimum requirement	Cylinder 1 in diameter x 2.5 in long	Not stated. Assumed similar to SRD sensor requirement.
Density range	400 - 1500 kg/m^3	Up to 1500 kg/m^3
Density accuracy	Standard: 10 kg/m^3 1 kg/m^3 and higher accuracy available (~1-1.25 % of liquid densities in test)	Standard: 1 kg/m^3 Higher accuracy available (~0.1-0.125 % of liquid densities in test)
Viscosity range	1 - 3000 cP	0.2 - 300 cP
Viscosity accuracy	Standard: 5 % of reading 1% and higher accuracy available	0.1 cP below 1 cP Standard: 5 % of reading Higher accuracy available
Reproducibility	Better than 1% of reading	Better than 1% of reading

6.2 Yokogawa Conductivity Sensor

Figure 15 – Yokogawa ISC40 inductive (toroidal, electrodeless) conductivity sensor

The Yokogawa ISC40 inductive conductivity sensor consists of two wire-wound metal toroids encased in a plastic body (PEEK or PFA) (Figure 15). One toroid is the drive coil and the other is the receive coil. An alternating voltage is applied to the drive coil and this induces a voltage in the fluid surrounding the coil. This voltage causes an ionic current to flow that is proportional to the conductance of the fluid. The ionic current induces an electronic current in the receive coil, which is measured. This induced current is directly proportional to the conductance of the solution.

Table 9 – Yokogawa ISC40 performance claims [50] [56]

Property	Range
Conductivity range	0 - 2000 mS/cm
Conductivity accuracy	0.5% of reading ± 1.0 µS/cm
Surrounding fluid minimum requirement	25 mm
Temperature range	-20 °C to 130 °C
Dynamic response	PEEK: t_{90} < 5 min PFA: t_{90} < 10 min
Pressure rating	PEEK: 0 – 20 barg PFA: 0 – 15 barg

7 TEST PROGRAMME

Details of the Low Pressure Multiphase Rig are given in Appendix A.

7.1 Sensor Installation

For the majority of data collected in this report, the sensors were installed in a 4 inch schedule 40 pipe spool, approximately 30 diameters downstream from a vertical installation, as shown in Figure 16 and Figure 17.

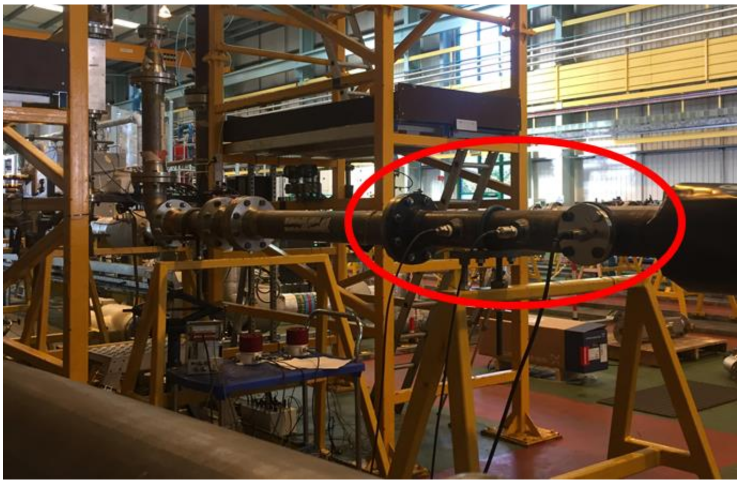


Figure 16 – Sensor pipe spool location in test line

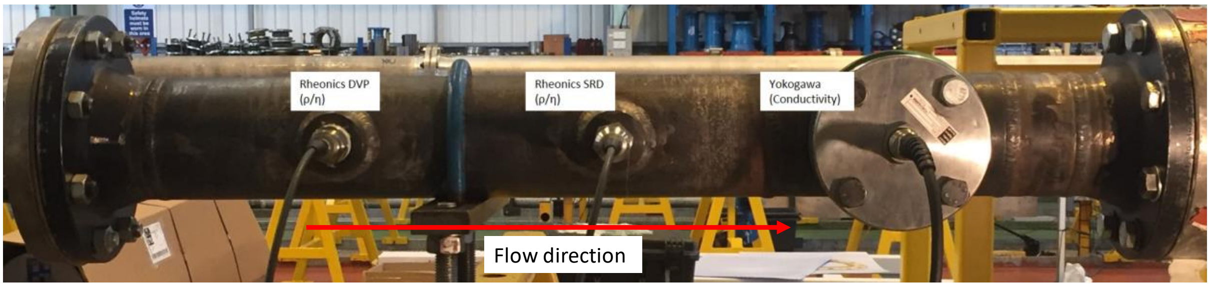


Figure 17 – location of sensors in pipe spool

The test layout upstream of the sensor installation differed for a small number of test points towards the end of testing when a 4 inch Coriolis meter was installed approximately 40 diameters upstream of the sensor location.

7.2 Test fluids

The test fluids used for this test programme are shown in below.

Table 10 – Test fluids and properties at ambient pressure and temperature

Fluid	Description	Density	Viscosity	Conductivity
Oil	Paraflex HT 9 refined oil	827 – 831 kg/m^3	14 – 18.77 cP	Non-conductive
Water	Aqueous solution of magnesium sulphate of concentration 90 g/l (based on $MgSO_4.7H_2O$)	1029 – 1043 kg/m^3	1.06 – 1.27 cP	Conductive
Gas	Nitrogen	5.5 – 22.7 kg/m^3	0.018 cP	Non-conductive

7.3 Test Matrix

The tests covered a broad range of flow conditions, allowing the sensor performance to be assessed across a range of ‘typical’ multiphase conditions, summarised in Table 11. The Rheonics SRD and Yokogawa sensors were present for all tests. The Rheonics DVP sensor was included later in the test sequence.

Table 11 – Test conditions summary

Property	Range
Test temperature	20 - 25 °C
Test pressure	10 barg
Gas flow rate	Up to 135 m^3/h
Gas superficial velocity	Up to 5 m/s
Liquid flow rate	Up to 110 m^3/h
Liquid superficial velocity	Up to 4 m/s
Water cut	0 - 100%
Gas volume fraction	0 - 100%
Number of liquid only points	Rheonics SRD and Yokogawa: 52 Rheonics DVP: 42
Number of gas and liquid points	Rheonics SRD and Yokogawa: 276 Rheonics DVP: 166

8 TEST RESULTS

8.1 Rheonics Density and Viscosity Sensors

The Rheonics density and viscosity sensors performed well for density measurements in liquid only conditions (oil only, water only or oil/water mixtures) (Figure 18) but did not perform well when gas was present (Figure 19). This was expected since the sensors are designed and calibrated for liquids. The y axis of the figures is the absolute value of the average error of the sensor compared to the reference measurements.

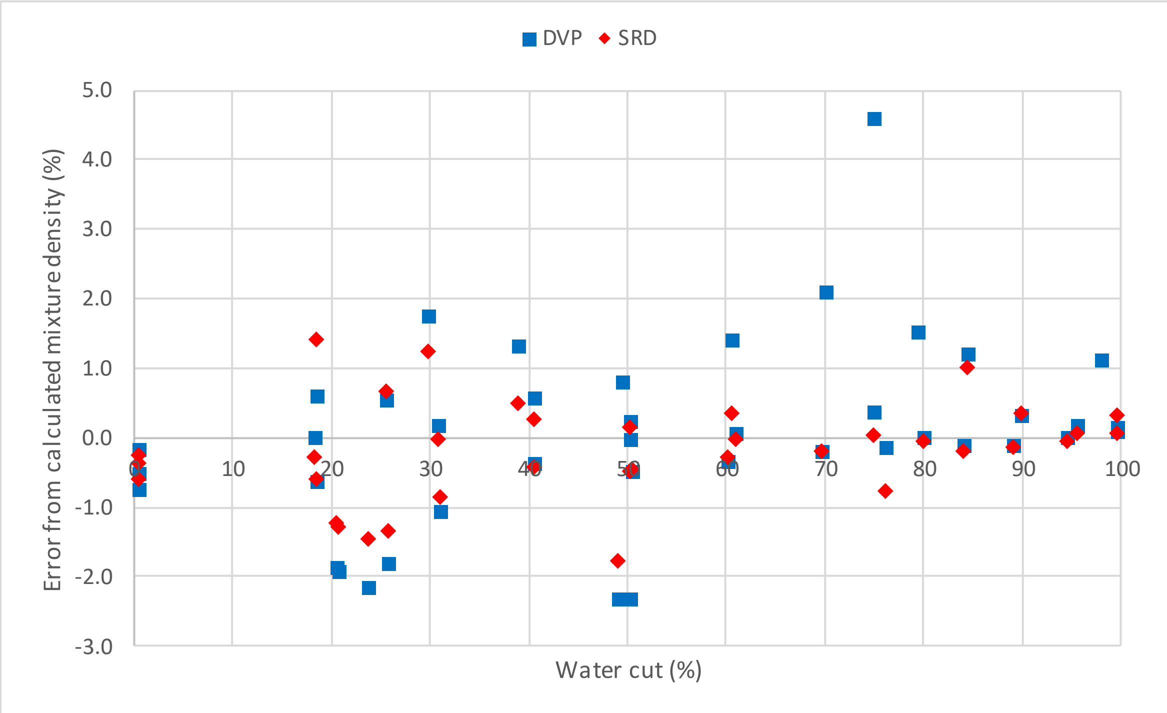


Figure 18 – Percentage error in measured density compared to reference liquid density for Rheonics sensors for liquid only test points (0% GVF)

Figure 18 shows that in all except one of the liquid only test points the density measured by the sensors differed by less than 2.5 % from the reference fluid density determined by NEL. The reason for the large error for the outlier is unknown but could potentially be related to flow regime or to a hysteresis effect with unrepresentative fluid remaining trapped in the sensor. The error did not show any significant trend with water cut. The average error was -0.06 % ± 2.1% to a 95% confidence level.

The SRD sensor was more susceptible to the signal dropping out which occurred during around 10 % of the liquid only test points. The reason for this is unclear but could be a feature of the signal processing if frequent changes in the mixture composition passing the sensor resulted in a signal that was not sufficiently stable to be reported. Theoretically the same effect could also have been caused by the presence of gas bubbles or solids, but this is considered highly unlikely during these test points. Figure 18 shows all the DVP sensor data and the SRD sensor data excluding the scans where the signal dropped out.

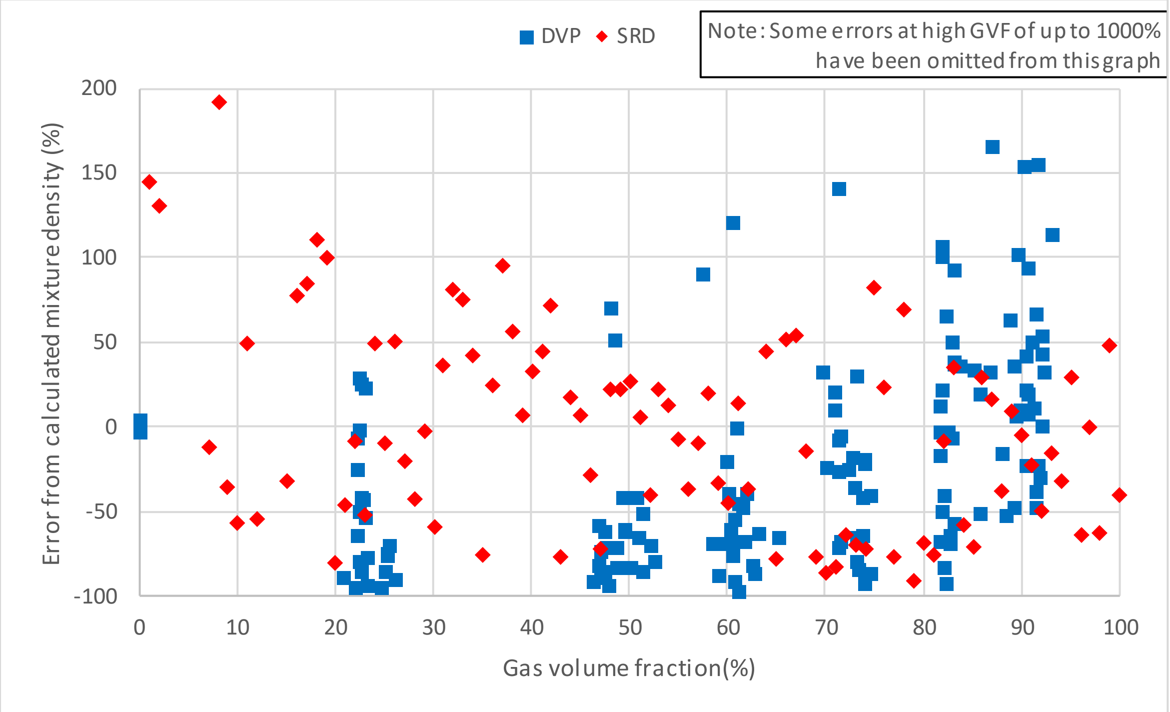


Figure 19 – Percentage error (absolute) in measured density compared to reference mixture density for Rheonics sensors for all test points (including liquid and gas)

Figure 19 shows that large density errors could occur when gas was present. As gas volume fraction increased, the maximum error increased, but at all test conditions with gas present the error could range between 0 % and over 100 % depending on the test conditions. The range of results is likely to reflect that the flow conditions at the sensor location were flow regime dependent and/or not always representative of the mixture.

For the fluids in the tests, the claimed 'accuracy' of the SRD and DVP sensors was approximately 1 - 1.25 % and 0.1 - 0.125 % respectively (Table 8). Combined with the uncertainties of the test facility flow measurement and a lack of certainty over whether the sensors were measuring a representative mixture, the average percentage difference in the liquid only tests of 0.6% between the sensors under test and the reference meters is likely to be within the uncertainty of the test facility flow measurements. This seems to be confirmed by the fact that there was no substantial difference between the SRD and DVP sensors' average errors when the sensors were operating correctly, despite the DVP sensor having a much lower uncertainty.

An additional source of error is that reference densities were based on temperature and pressure measurements at the facility test section where customer meters were installed. The sensor pipe spool was between 2 and 4 m away from these measurements depending on the configuration of the meter under test.

Viscosity measurements were less reliable and are more difficult to assess due to mixture effects on viscosity. General trends of viscosity increasing with decreasing water cut were noted as would be was expected since high viscosity emulsions do not form with these test fluids under normal operating conditions. Average errors of around 20 % were seen for single phase liquid measurements (Figure 20).

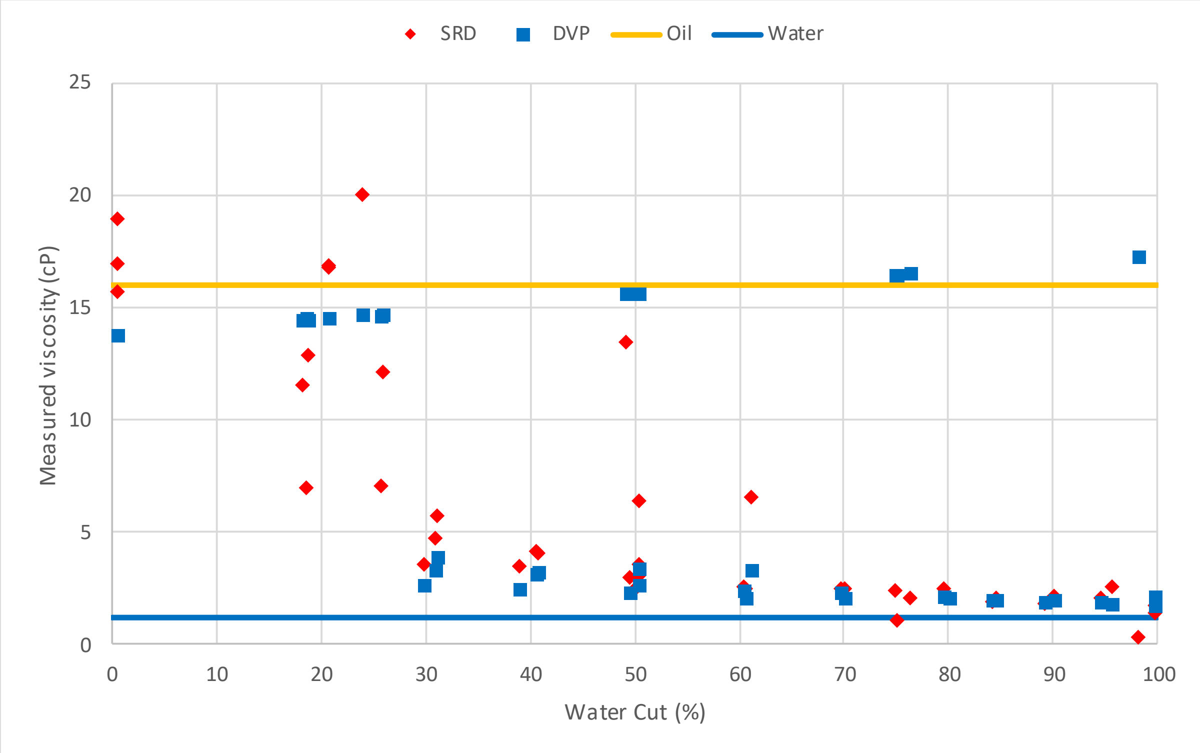


Figure 20 – Measured viscosity versus water cut for Rheonics sensors for liquid only test points

In terms of availability, robustness and ease of implementation, the Rheonics sensors met the work package requirements.

8.2 Yokogawa Conductivity Sensor

The test programme contained two separate series with slightly different water densities of 1030 kg/m^3 and 1043 kg/m^3. While this represents an insignificant change in density of 1.2 % compared to the variations seen by the Rheonics sensors, the increased magnesium sulphate concentration has a significant effect on the conductivity varying from 19.0 mS/cm for the low density case to 24.5 mS/cm at high density.

However, these conductivity values are for a pure magnesium sulphate solution. Some tests in the facility are carried out, at a client's request, with a sodium chloride solution which, for the same density, has a much higher conductivity (63 mS/cm and 82 mS/cm respectively).

Although care is taken when draining down and refilling the facility with the appropriate solution, some water of the previous solution inevitably remains trapped in the pipework. Some of the conductivity values for the high density tests exceed the pure magnesium sulphate value and this is presumed to be due to cross-contamination. For the low density tests, tests were not carried out at above 75% water cut and therefore the effects of any cross-contamination are not readily apparent.

For the vast majority of the test work carried out at NEL the water density is the key parameter, not the conductivity, and this is reflected by the absence of an in line reference conductivity measurement in the test loop. Where the conductivity needs to be monitored, this is done by testing samples of the water at intervals. For the high density 100 % water cut liquid points the conductivity measured by the sensor was within 5 % of a water sample taken from the test facility and measured using a separate conductivity instrument.

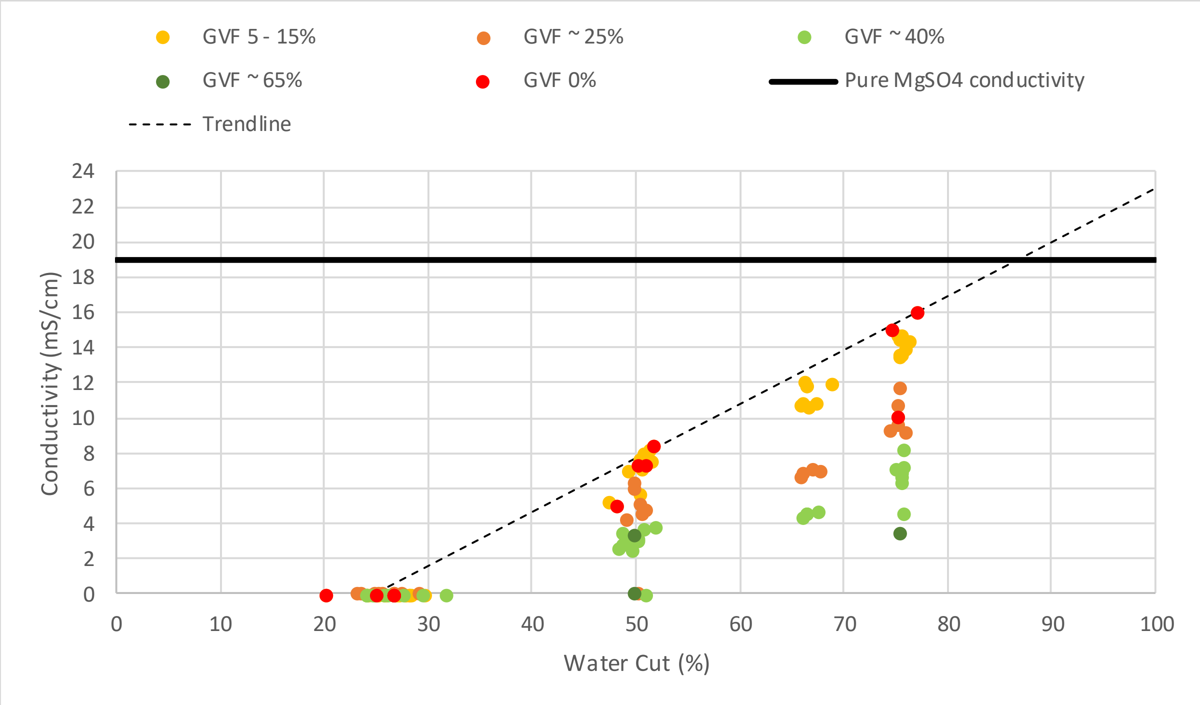


Figure 21 – Measured conductivity versus water cut for Yokogawa conductivity sensor for the low conductivity test points (including liquid and gas)

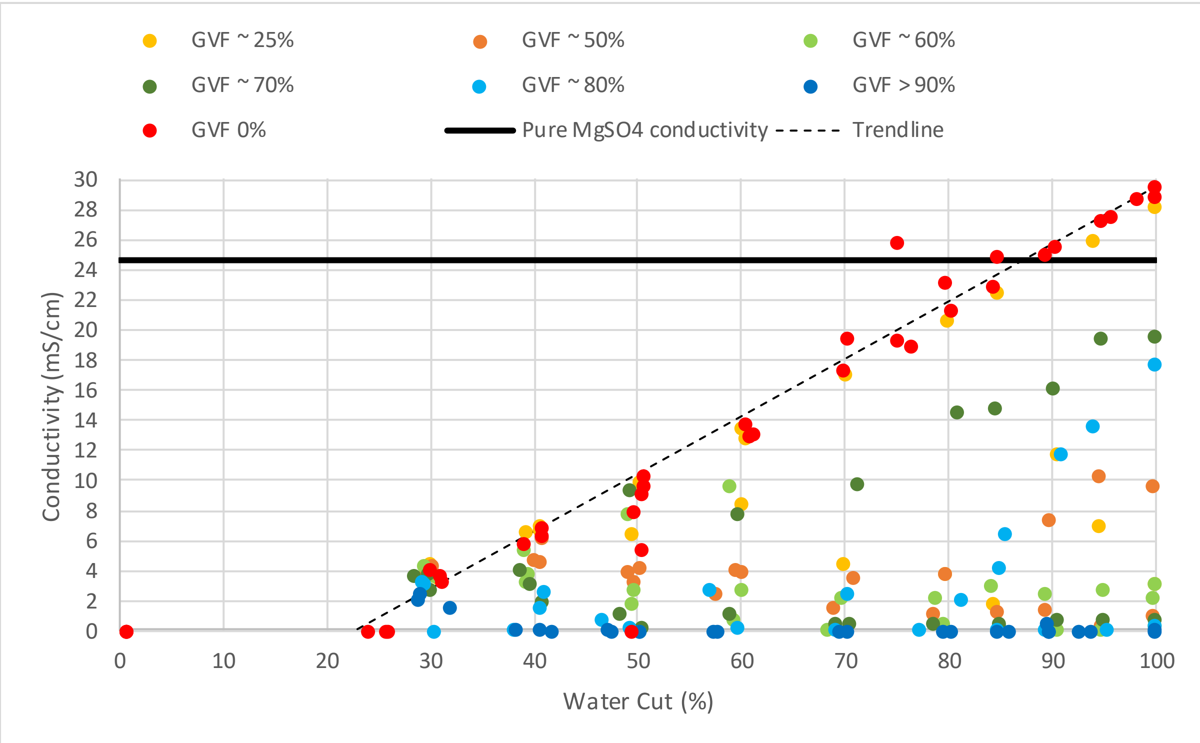


Figure 22 – Measured conductivity versus water cut for Yokogawa conductivity sensor for the high conductivity test points (including liquid and gas)

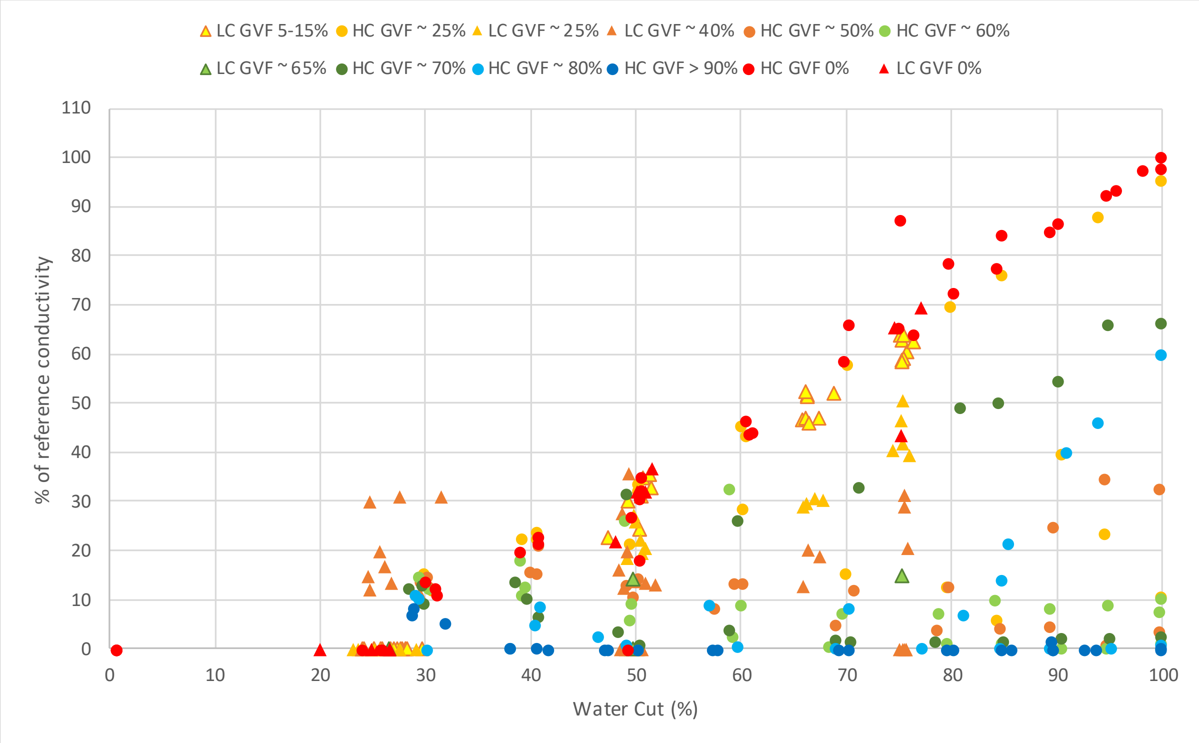


Figure 23 – Measured conductivity relative to reference versus water cut for Yokogawa conductivity sensor for all test points (including liquid and gas)

As with the Rheonics sensors, the Yokogawa sensor appeared to perform well for liquid only test conditions but not when large volumes of gas were present (Figure 23).

The measured conductivities for liquid only test points showed a clear trend of conductivity decreasing linearly with decreasing water cut.

For water cuts below 25 %, the sensor no longer gave a reading, assumed to be due to the fluid becoming oil continuous.

For GVFs up to 20 % the sensor gave the same readings as in the liquid only tests (apart from one outlier at 70 % water cut), assumed to be due to the flow regime with gas restricted to the top of the pipe and the sensor fully submerged.

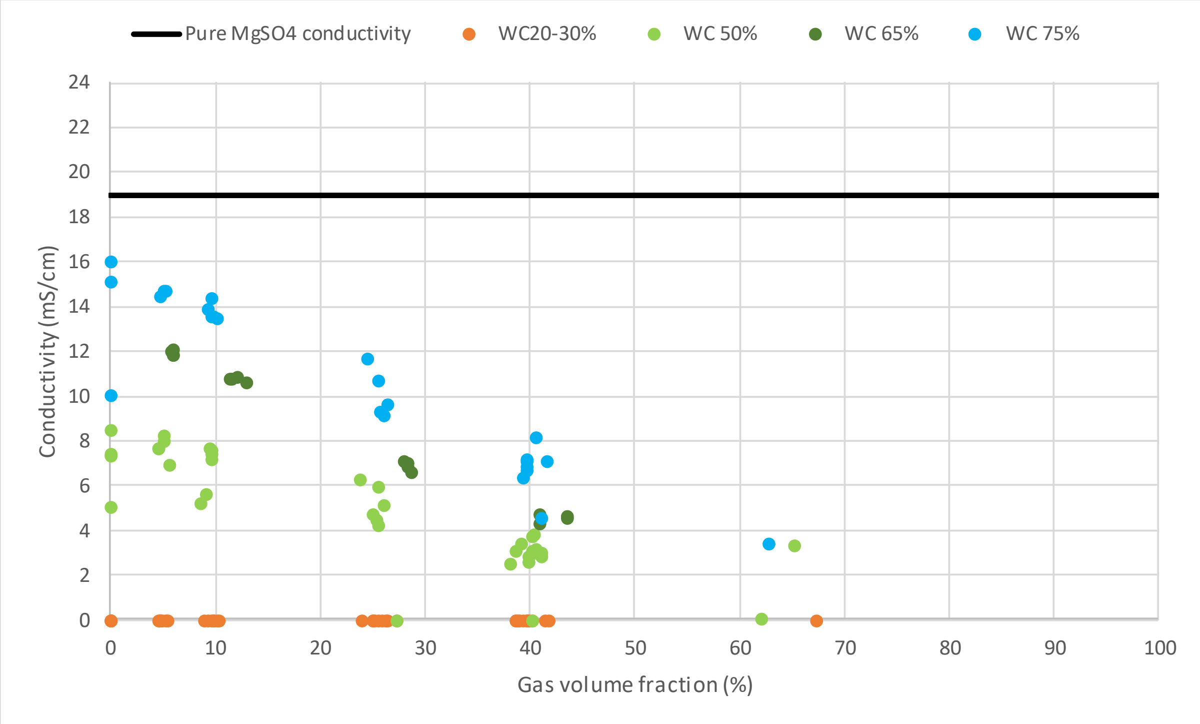


Figure 24 – Measured conductivity versus gas volume fraction for Yokogawa conductivity sensor for the low conductivity test points (including liquid and gas)

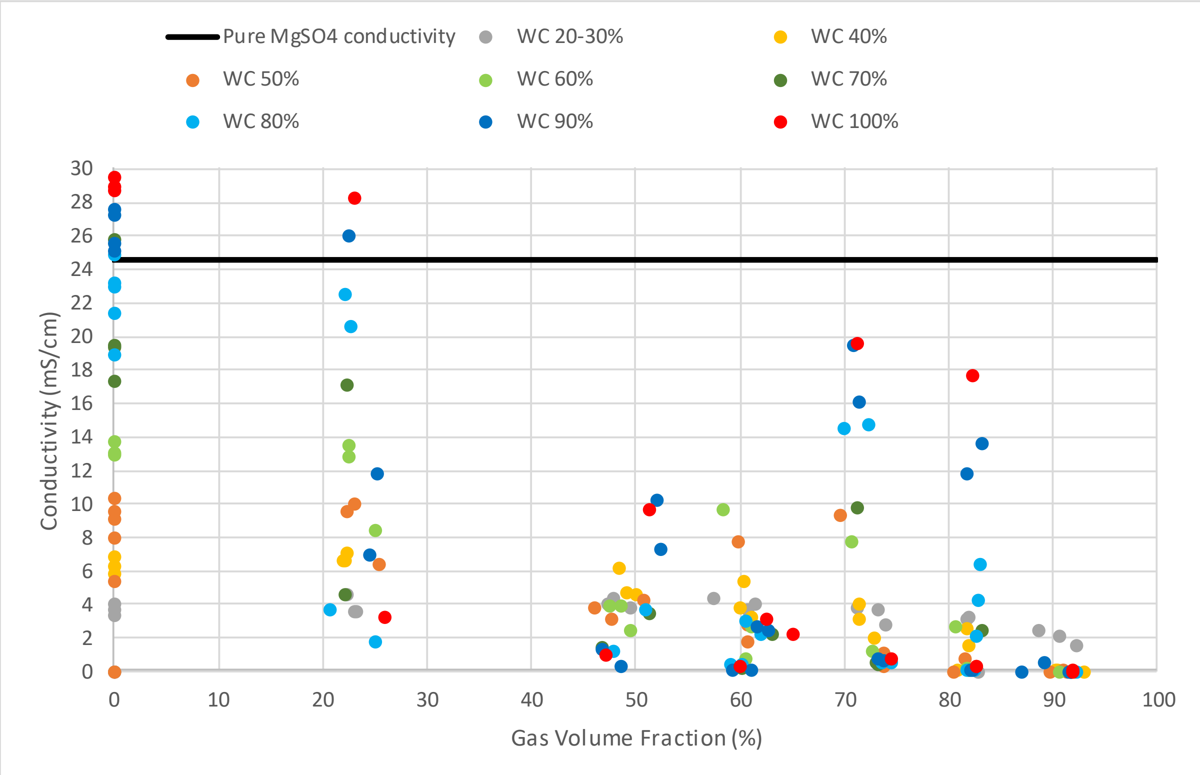


Figure 25 – Measured conductivity versus gas volume fraction for Yokogawa conductivity sensor for the high conductivity test points (including liquid and gas)

8.3 Potential Uses of Sensors to Infer Flow Information

The Rheonics sensors can be used to give density and viscosity measurements in liquid flows. The wide variability in readings with the presence of gas makes their readings unreliable, although this is likely to be flow regime dependent.

The Yokogawa sensor could be used to provide conductivity measurements in liquid flows and infer water cut in water continuous conditions if the water only conductivity is known. The ability to function in three phase flow is dependent on flow regime, i.e. whether the sensor remains fully submerged in the liquid.

9 CONCLUSIONS

Overall, none of the sensors tested appear suitable for accurate fluid property measurements in multiphase flows with high GVF. This was expected since none of the sensors tested are designed for gas/liquid flows. However, all sensors performed well under most liquid only test conditions and provided some useful data at low GVF.

These sensors have the potential to be used in low GVF flows if mounted in a suitable location and coupled with a tomography system to confirm whether the sensor is fully submerged in the liquid phases and therefore when their output can be relied on.

10 REFERENCES

[1] C. Mills, “Multiphase Flow Meter Diagnostics,” NEL, 2018.

[2] NEL, Multiphase and Wet Gas Flow Measurement Training Course, NEL, 2016.

[3] NEL, Good Practice Guide: An Introduction to Multiphase Flow Measurement, National Measurement System.

[4] NEL, Principles and Practice of Flow Measurement Course Notes, NEL, 2015.

[5] “Agar Corporation- MPFM- 50 SERIES,” [Online]. Available: http://www.agarcorp.com/literature/MPFM50.html.

[6] “Emerson- Multiphase Metering Principles,” [Online]. Available: http://www.emerson.com/en-us/automation/measurement-instrumentation/flow-measurement/multiphase-meters.

[7] Emerson, “Roxar Watercut Meter Product Data Sheet, RX-PS002227, Rev A,” Jun 2019.

[8] “Weatherford Multiphase Flow Measurement,” [Online]. Available: http://www.weatherford.com/en/products-services/production/flow-measurement/multiphase-flow-measurement#.

[9] “FMC Technologies- Multiphase Meters,” [Online]. Available: http://www.fmctechnologies.com/en/Multiphase-meters/Benefits.aspx.

[10] “ABB- Oil, gas, and water flow rate in real-time – measurement becomes multiphase,” [Online]. Available: http://new.abb.com/products/measurement-products/flow/multiphase-flowmeters/oil-gas-and-water-in-real-time-flow-rate.

[11] “Schlumberger- Vx Spectra Multiphase Flowmeter,” [Online]. Available: http://www.slb.com/services/characterization/testing/multiphase/spectra.aspx.

[12] “Pietro Fiorentini- Multiphase Flow Measurement,” [Online]. Available: https://www.fiorentini.com/media/files/143_756_flowatch_2013_1.pdf.

[13] M-Flow, “M-Flow Multiphase Monitoring,” M-Flow, 2018. [Online]. Available: http://www.m-flow-tech.com/applications/wellhead-multiphase-monitoring/.

[14] Abbon, “Abbon 3PM Multiphase Flow Meter,” 2018. [Online]. Available: http://abbon.com/abbon3pm/.

[15] Expro, “Expro Sonar Monitor,” Expro, 2018. [Online]. Available: https://www.exprogroup.com/products-services/meters/permanent-well-flow-monitoring-expro-meters-sonarmonitor.

[16] Solartron, “Solartron Dualstream,” 2018. [Online]. Available: http://www.solartronisa.com/products/dualstream/dualstream-2.

[17] Neftemer, “Neftemer Multiphase Meter,” 2018. [Online]. Available: http://www.neftemer.com/multiphase-meters.html.

[18] L. Zhao, Y. Hu, T. Wang, J. Ding, X. Z. Liu and Z. Jiang, “A MEMS Resonant Sensor to Measure Fluid Density and Viscosity under Flexural and Torsional Vibrating Modes,” *Sensors,* vol. 16, no. 6, 2016.

[19] K. Folgero and J. Kocback, “Uncertainty analysis of multiphase flow meters used for allocation measurements: Field experiences and future...,” in *31st Int. North Sea Flow Measurement Workshop*, 2013.

[20] C. Harrison, S. Ryu, A. Goodwin, K. Hsu, E. Donzier, F. Marty and B. Mercier, "A MEMS Sensor for the Measurement of Density-Viscosity for Oilfield Applications," *Reliability, Packaging, Testing, and Characterization of MEMS/MOEMS V,* vol. 6111, 2006.

[21] G. Milller, B. Pinguet, P. Mosknes and B. Theuveny, "The Influence of Liquid Viscosity on Multiphase Flow Meters," in *8th South East Asia Hydrocarbon Flow Measurement*, 2009.

[22] A. Gryzlov, E. Undheim, E. Nyfors and L. Jordaan, "Challenges with salinity measurements in multiphase flow metering- Emerson," in *Norwegian Society For Oil and Gas Measurement*, 2015.

[23] M. J. da Silva, "Impedance Sensors for Fast Multiphase Flow Measurement and Imaging," TU Dresden , 2008.

[24] B. Pinguet, C. Gang and M. Fiore, "An Innovative Salinity Tracking Device for Multiphase and Wet Gas Meters for any GVF and WLR," in *South East Asia Flow Measurement Conference*, 2016.

[25] E. Paez, M. Azpura, C. Tremola and R. Callarotti, "Uncertainty Minimization In Permittivity Measurements In Shielded Dielectric Resonators," *Progress In Electromagnetics Research M,* vol. 26, pp. 124-141, 2012.

[26] K. Elkow and K. Rezkallah, "Void fraction measurements in gas–liquid flows using capacitance sensors," *Measurement Science and Technology,* vol. 7, pp. 1153-1163, 1996.

[27] Schlumberger, "InSitu Density- Reservoir fluid density and viscosity sensor," Schlumberger, 2015. [Online]. Available: http://www.slb.com/~/media/Files/evaluation/product_sheets/wireline_open_hole/insitu_fluid/insitu_density_ps.pdf.

[28] Schlumberger, "InSitu Viscosity- Reservoir Fluid Viscosity Sensor," Schlumberger, 2014. [Online]. Available: http://www.slb.com/~/media/Files/evaluation/product_sheets/wireline_open_hole/insitu_fluid/insitu_viscosity_ps.pdf.

[29] Rheonics, "Rheonics Vibrational Sensor Technology Whitepaper," 2015.

[30] Rheonics, "Rheonics SRD Sensor Datasheet," 2017.

[31] T. Sensors, "Data sheet: Technical description and installation instructions- Density module for liquid hydrocarbons," 2017.

[32] E. TrueDyne, *Installation of TrueDyne Sensor,* 2017.

[33] AveniSense, "Devil Liquid Density and Viscosity Meter Brochure," 2017.

[34] VAF, "VAF ViscoSense 3D Brochure," 2017.

[35] Centec, "Process Density Transmitter Rhotec TR Instruction Manual," 2012.

[36] Parker, "Fluid Property Sensor FPS2000- Installation guide and specifications," 2013.

[37] M. O'Keefe, S. Godefroy, R. Vasques, A. Agenes, P. Weinheber, R. Jackson, M. Ardila, W. Wichers, S. Daungkaew and I. De Santo, "In-Situ Density and Viscosity Measured by Wireline Formation Testers," in *2007 Society of Petroleum Engineers Asia Pacific Oil and Gas Conference*, 2007.

[38] A. Goodwin, E. Donzier, M. Manrique, S. Pelham and G. Meeten, “Fluid Property Sensors (Schlumberger)”. Patent US 7,434,457 B2, 2008.

[39] B. Ochoa, T. Kruspe and J. Goodbread, “A New Sensor for Viscosity and Fluid Density Measurement for Oil Well Drilling Applications,” in *Sensors and Measurement Systems*, 2014.

[40] B. Ochoa, T. Kruspe and M. Meister, “A New Sensor for Viscosity and Fluid Density Measurement at High Temperature and High Pressure in a Wireline and Lwd Tool,” in *Annual Logging Symposium*, 2014.

[41] Rheonics, “Rheonics DVM Brochure,” Rheonics, 2015.

[42] Rheonics, “Rheonics SRV Brochure,” Rheonics, 2015.

[43] Centec, “Rhotec- Measurement of Density and Concentration,” 2017.

[44] CMR, “Salinity and Water-Liquid Ratio Sensor,” 2017. [Online]. Available: http://cmr.no/projects/10442/salinity-and-water-liquid-ratio-sensor/.

[45] Yokogawa, “ISC40 Inductive Conductivity sensor and fittings- General Specification,” 2017.

[46] Emerson, “Theory and Application of Conductivity,” 2010.

[47] Yokogawa, “Yokogawa Conductivity Sensors,” 2017. [Online]. Available: https://www.yokogawa.com/solutions/products-platforms/process-analyzers/liquid-analyzers/conductivity-sensors/.

[48] Yokogawa, “Model SX42 General Specification,” 2016.

[49] Yokogawa, “2-Wire Dual Channel Transmitter/Analyzer FLEXA,” 2017. [Online]. Available: https://www.yokogawa.com/solutions/products-platforms/process-analyzers/liquid-analyzers/ph-analyzers/two-wire-transmitter-analyzer-flxa21/#Downloads.

[50] Yokogawa, “Inductive Conductivity Converter ISC450 General Specification,” 2017.

[51] Honeywell, “Series 5000TC Operation and Maintenance Manual”.

[52] Honeywell, “APT2000 Toroidal Conductivity Transmitter Manual,” 1999.

[53] Emerson, “Rosemount™ 228 Toroidal Conductivity Sensor Product Data Sheet,” 2017.

[54] Emerson, “Rosemount™ 1056 Dual-Input Intelligent Analyzer Manual,” 2017.

[55] Rheonics, “Rheonics DVP Sensor Datasheet,” 2017.

[56] Yokogawa, “ISC40 Inductive Conductivity Sensor and Fittings General Specification,” 2017.

APPENDIX A NEL LOW PRESSURE MULTIPHASE FLOW FACILITY

A.1 Test Facility Layout

A schematic of the NEL Multiphase Facility is shown in Figure A1. The facility is based around a 3 phase separator which contains the working bulk fluids. The oil and water are re-circulated around the test facility using two variable speed pumps at pressures up to 15 barg. For safety reasons, nitrogen is used as the gas phase and can be delivered at up to 0.5 kg/s by evaporation of liquid nitrogen on demand. The delivery pressure of the nitrogen is up to 17 bar at the reference measurement location. After passing through the test section, the nitrogen is exhausted to atmosphere from the separator.

A test section of up to 30 m long and 12 m high can be accommodated in the 60 m horizontal pipe. The line sizes installed in the test section are typically between DN25 to DN150. A wide range of flanges can be accommodated.

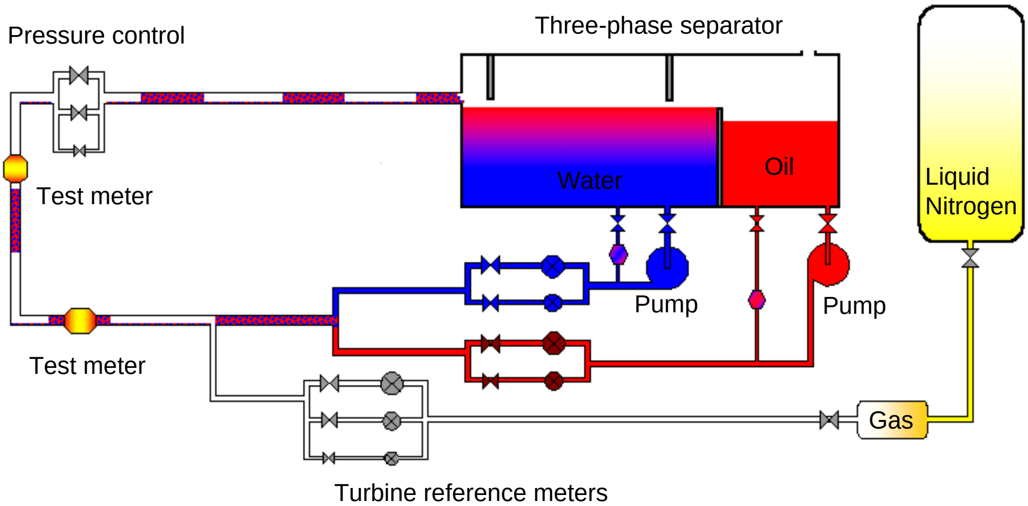


Figure A1 - Schematic of NEL Multiphase Flow Facility

A.2 Test Fluids

Unless a client has different requirements, the fluids used in the facility are:

- Paraflex HT 9 refined oil.
- An aqueous solution of Magnesium Sulphate of concentration 90g/l (based on $MgSO_4.7H_2O$).
- Nitrogen gas

The viscosity of the oil can be altered to suit client requirements by heating or cooling the test fluids. Heat exchangers allow the temperature of the oil and water to be maintained at between 10° and 50°C within ±1°C. Normal operating temperatures are 20°C and 35°C.

The facility maximum flowrates are:

- Oil: 145 m^3/h
- Water: 145 m^3/h
- Nitrogen: 1500 Sm^3/h

A.3 Control

An automated SCADA system allows a single operator to control the entire facility from a PC workstation. The PC is linked to a PLC via an EtherNet connection which permits a response time from command to action of less than one second. Client instrument data and facility instrument information are collected via a separate data acquisition system.

A.4 Separation

At the centre of the facility is a large three-phase gravity separator, which contains approximately 25 m^3 of water and 20 m^3 of oil. This acts as the storage vessel for the liquids currently under test, in addition to separating the fluids for recirculation. Various devices are employed inside the separator to speed up separation including baffles and parallel plate pack systems. The liquids can be re-circulated indefinitely across much of the operating envelope of the facility. The level of liquid cross-contamination is continually monitored and the reference liquid flowrates corrected. The separator is equipped with transfer pumps to move settled liquids between the water and oil compartments.

A.5 Reference Flowrate Measurements

The oil and water are separately drawn from the separator and pumped through the oil and water metering circuits respectively. Both metering circuits have a choice of two flowmeters, according to the flowrate required. Oil is metered using Faure Herman helical blade turbine meters, with the following calibrated ranges:

1¼-inch turbine meter	0.43 to 5.5 l/s
3-inch turbine meter	4.42 to 39.9 l/s

The water is metered using flat-blade turbine meters with the following calibrated ranges:

1½-inch turbine meter	0.54 to 7.99 l/s
3-inch turbine meter	4.75 to 40.0 l/s

The nitrogen is metered through a choice of three gas turbine meters according to the flowrate required. The calibrated ranges of these flow meters are:

½-inch turbine meter	0.59 to 2.18 l/s
1-inch turbine meter	1.6 to 11.9 l/s
3-inch turbine meter	8.8 to 29.5 l/s

To allow testing below the range of the facility gas turbine meters, an additional Endress & Hauser DN8 Coriolis meter can be installed in series, with a flow range of 0.7 to 15 g/s.

The gas flowrate is measured at the gas supply pressure (typically 16 bar). By operating the test section at reduced pressures it is possible to cover the full range of gas volume fractions (GVFs), with gas superficial velocities up to 20 m/s in the 4-inch test section.

A.6 Cross-contamination Monitoring

An additional bypass stream flows through monitors to measure the cross- contamination of the liquid phases. This sample loop is taken from the main pump outlet, passed through a densitometer and returned to the separator. Prior to commencing a test programme clean test fluid samples are drawn from the separator and their densities are determined over a range of temperatures using an Anton Paar DMA5000 laboratory densitometer. Cross contamination in the sample loops is calculated by:

$$Water\ cut = \frac{\rho_{indicated} - \rho_{oil}}{\rho_{water} - \rho_{oil}}$$

The water-in-oil content of the oil flow stream and the oil-in-water content of the water stream are determined from an online density measurement using a Parr Scientific vibrating tube densitometer.

A.7 Pressure and Temperature

For accurate volumetric metering of the gas phase, it is necessary to correct for expansion of the gas in the test section, so that the gas volume fraction and gas flowrate at the device under test (DUT) can be calculated. The pressure and temperature of the gas and of the multiphase mixture are therefore measured at a number of locations around the facility:

- At the reference gas meters
- At the inlet to the multiphase test section
- At intervals along the multiphase test section
- At the multiphase meter test location

Volume and, consequently, water cut (WC) corrections are applied to local conditions at the test location.

A.8 Traceability of Reference Measurements

The instrumentation provided for the facility is of the highest accuracy practicable, and these instruments are calibrated against accurate standards, with a traceable record of the calibrations being maintained.

Most reference instruments are calibrated annually. The oil and water reference turbine meters are calibrated against the UK primary national standard facilities at NEL. The gas reference turbine meters are calibrated against reference sonic nozzles traceable to international standards under ISO/IEC 17025. The pressure transmitters and platinum resistance thermometers are calibrated against standard equipment held in the multiphase laboratory.

The densities of the separate oil and water phases are determined off-line prior to a customer's evaluation or test. These fluid densities are determined using an Anton Paar DMA5000 laboratory densitometer and are used in conjunction with the contamination measurement densitometers to correct the reference liquid flowrates. The conductivity of the water phase can be determined using a standard conductivity meter.

A.9 Uncertainty Analysis

It is also important to be aware of the uncertainties which are present in the reference flowrates, taking into account the uncertainties of the calibrated instruments, observed fluctuations in flowrates during tests, and combination of the readings of a number of instruments to give the final values.

The exact uncertainties of a particular reference flowrate will depend on the values of the individual gas, oil and water flowrates and the ratio between them as well as pressure, temperature and liquid cross-contamination levels.

During 2010, NEL carried out a complete review of the uncertainty of the multiphase flow facility and achieved accreditation for the facility to ISO 17025. NEL is satisfied to quote a combined uncertainty that covers all aspects of the flow measurements including installation and process flow effects for this report. Over the majority of the operating range of the NEL multiphase flow facility the combined uncertainties are:

- Gas flow < 1.5%
- Liquid flow < 1.0%
- Water cut < 1.0% Absolute

One of the most significant contributing factors to the oil and water flowrate uncertainties is the uncertainty in the cross-contamination monitoring. This will lead to the greatest error in oil flowrate at high water cut and the greatest error in water flowrate at low water cut. The biggest contribution to the gas flowrate uncertainty is the test section pressure. The resulting error in gas flowrate is greatest at low test section pressure (which usually occurs when testing at high GVF). Since the uncertainties in water, oil and gas flow rate are uncorrelated, they are combined using the Root Sum Square method and the uncertainties in GVF and in total liquid flowrate are typically much smaller than the relative uncertainties for each stream.

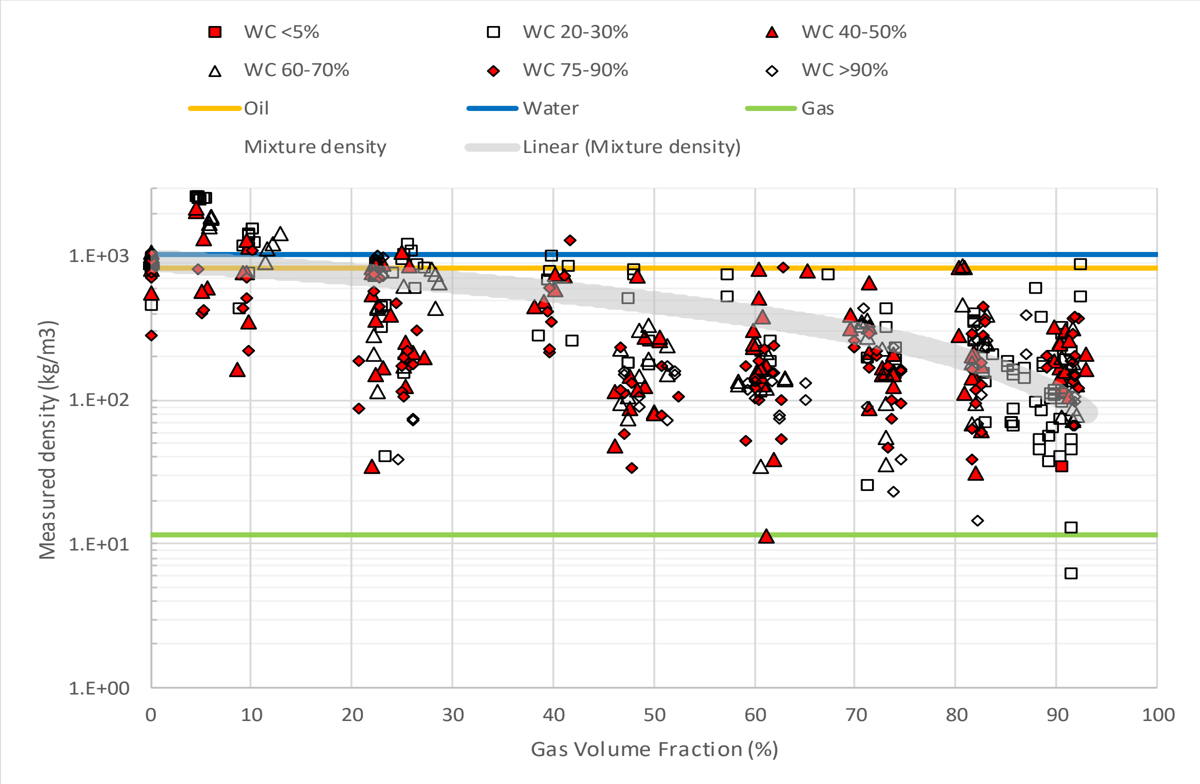
All uncertainties quoted are expanded uncertainties based on a standard uncertainty multiplied by a coverage factor k=2. This provides a level of confidence of approximately 95%.

APPENDIX B TEST RESULTS

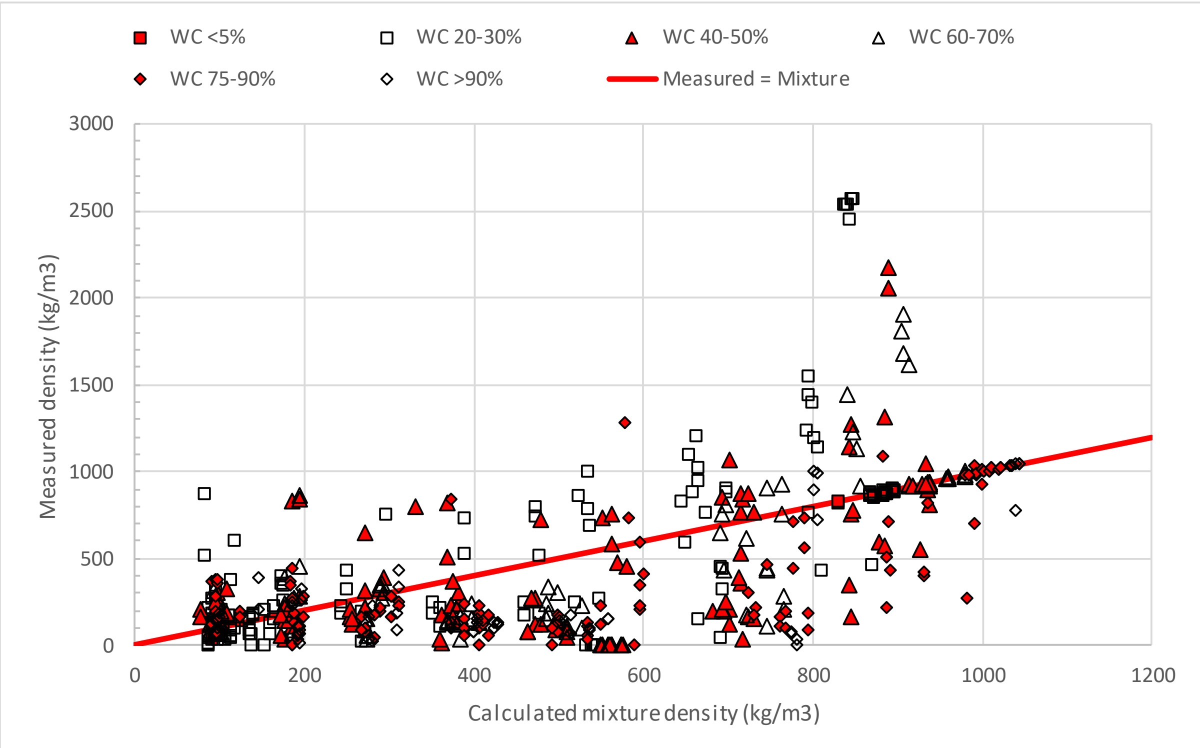
B.1 Density Measurements

Please note that the calculated mixture density below assumes a homogeneous mixture (with zero slip).

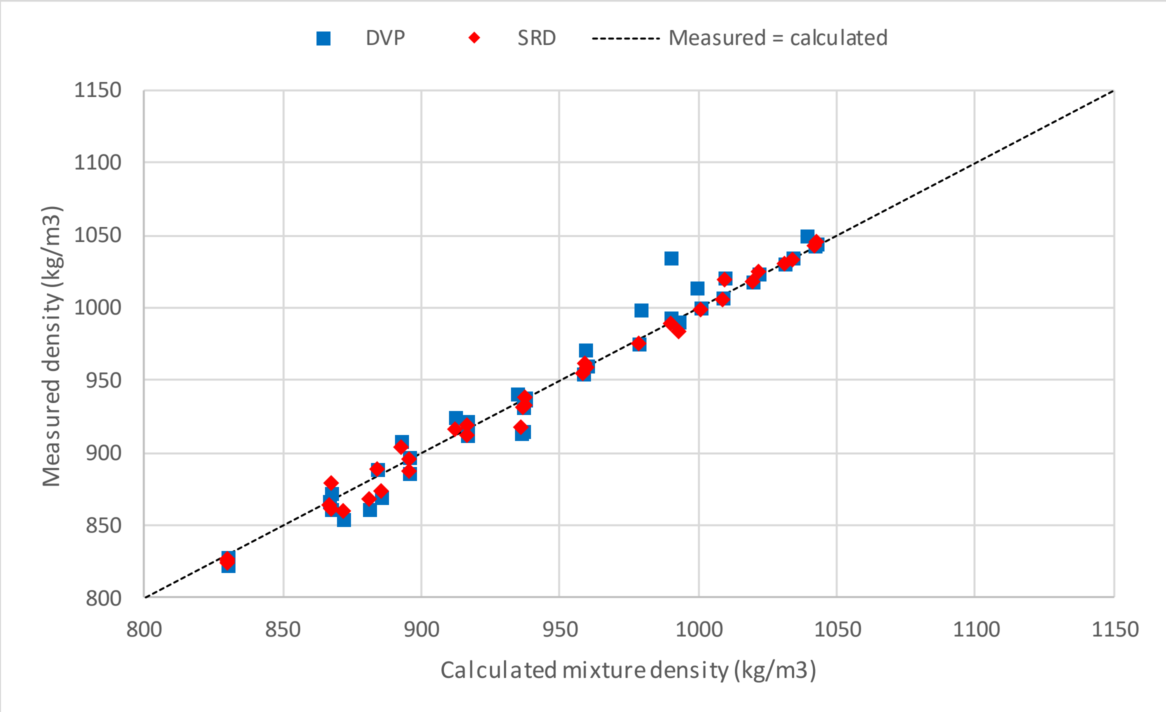
B1.1 All density data for both sensors



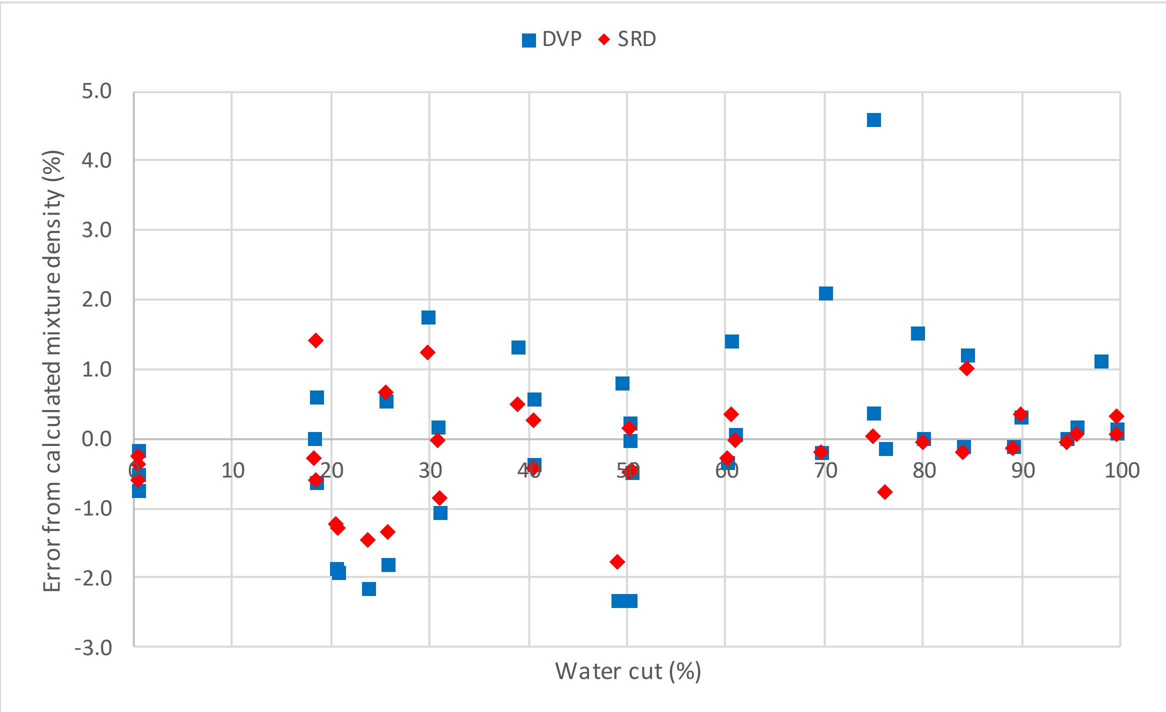
B1.2 Measured density against calculated mixture density – all points



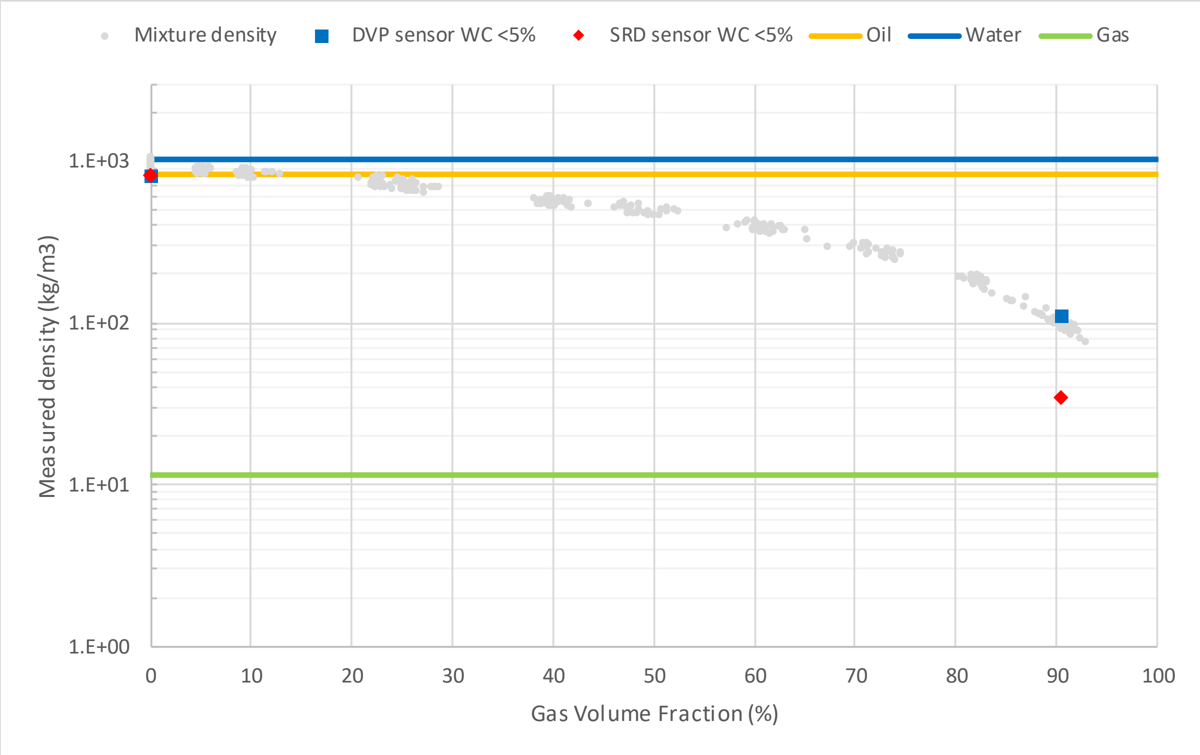
B1.3 Measured density against calculated mixture density for 0% GVF



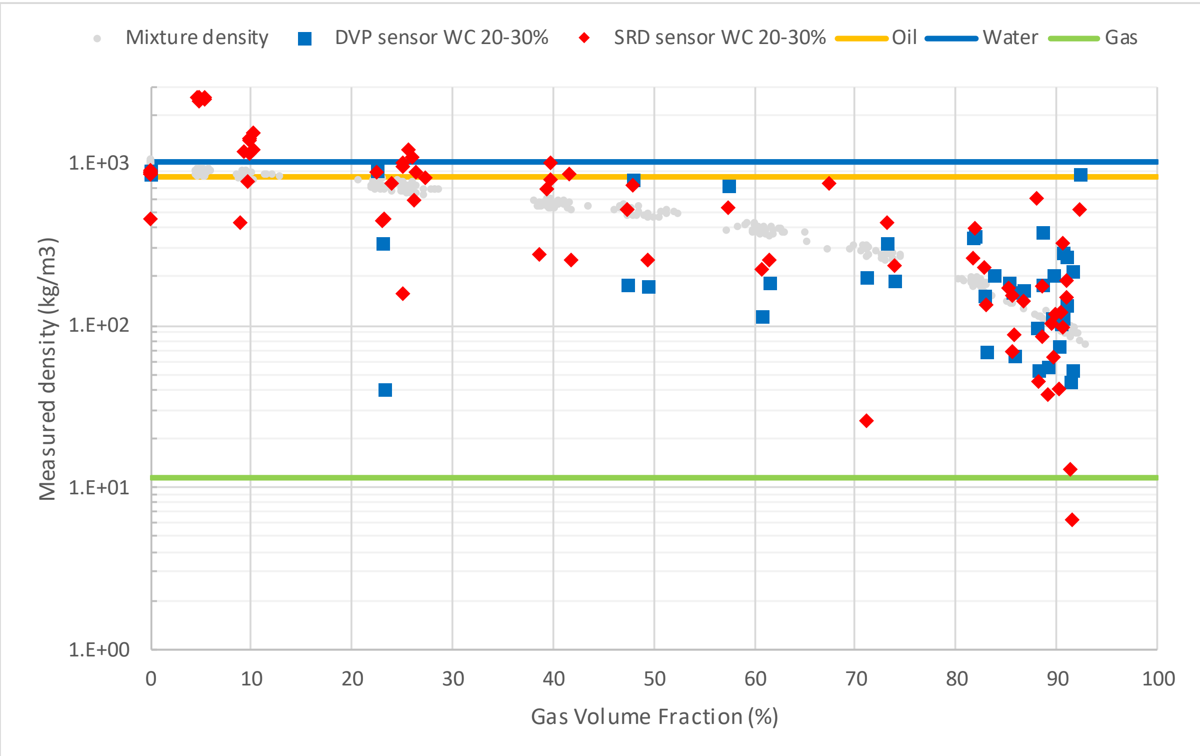
B1.4 Error in measured density for 0% GVF



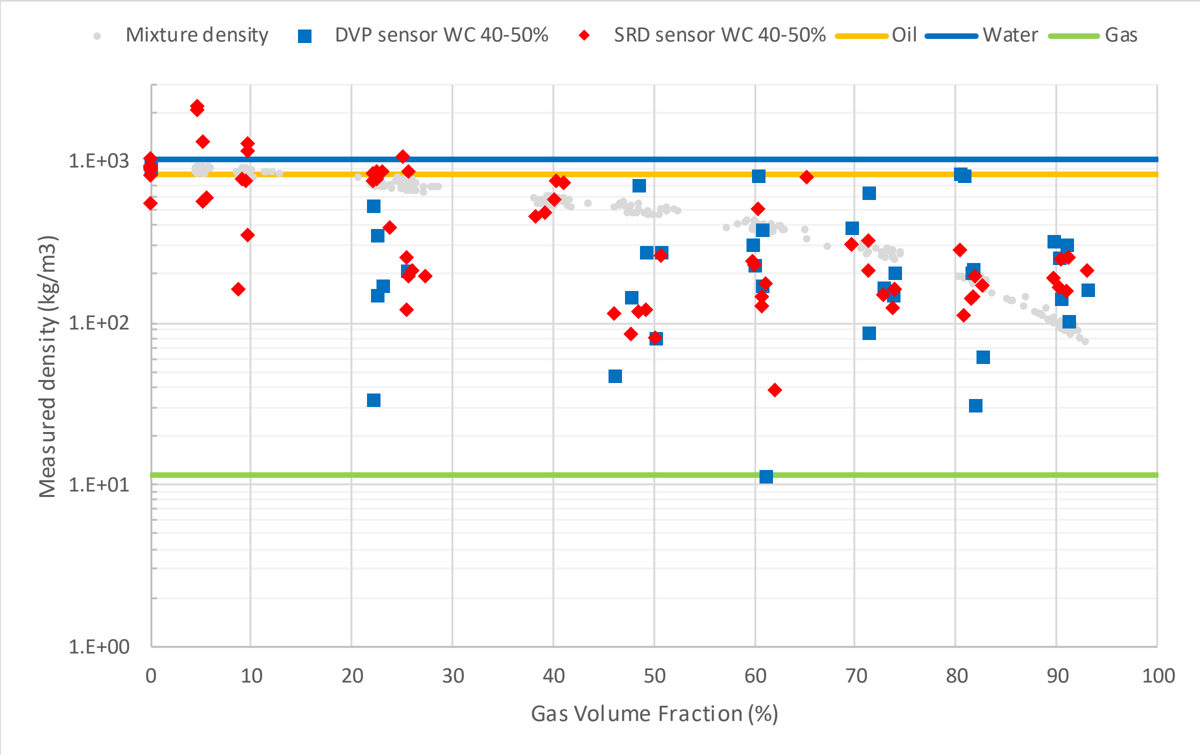
B1.5 Density Results for Water Cut <5%



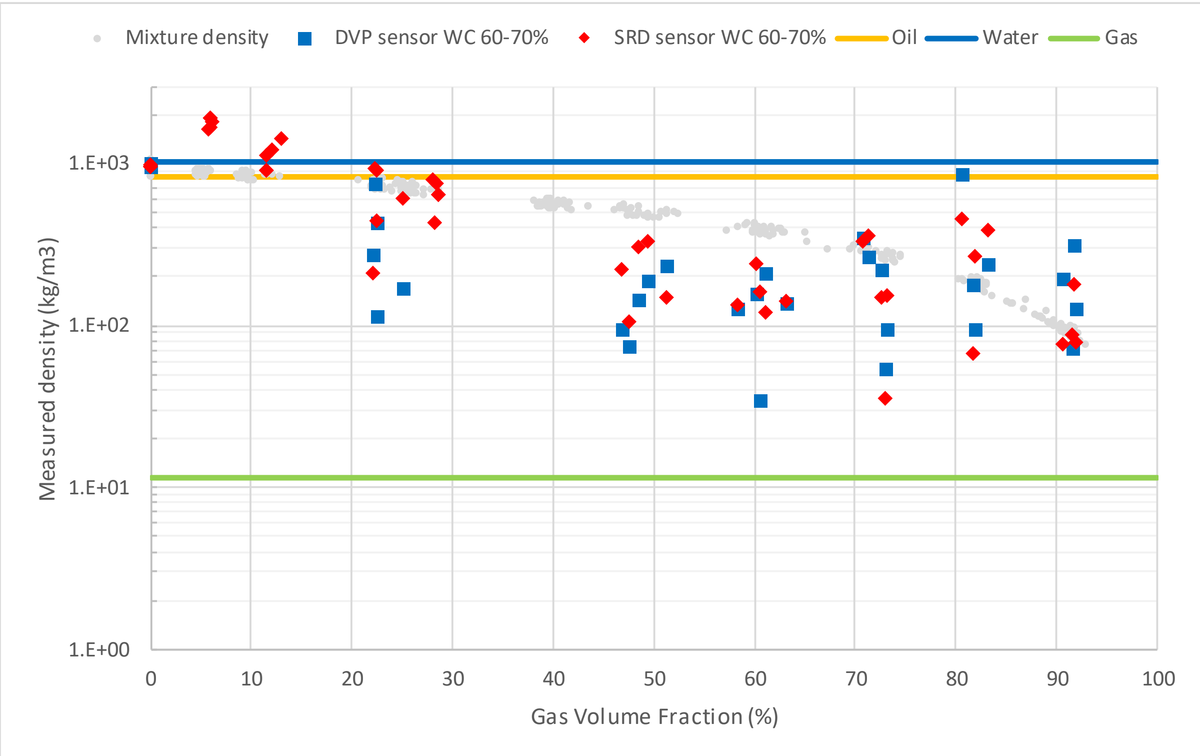
B1.6 Density Results for Water Cut 20-30%



B1.7 Density Results for Water Cut 40-50%

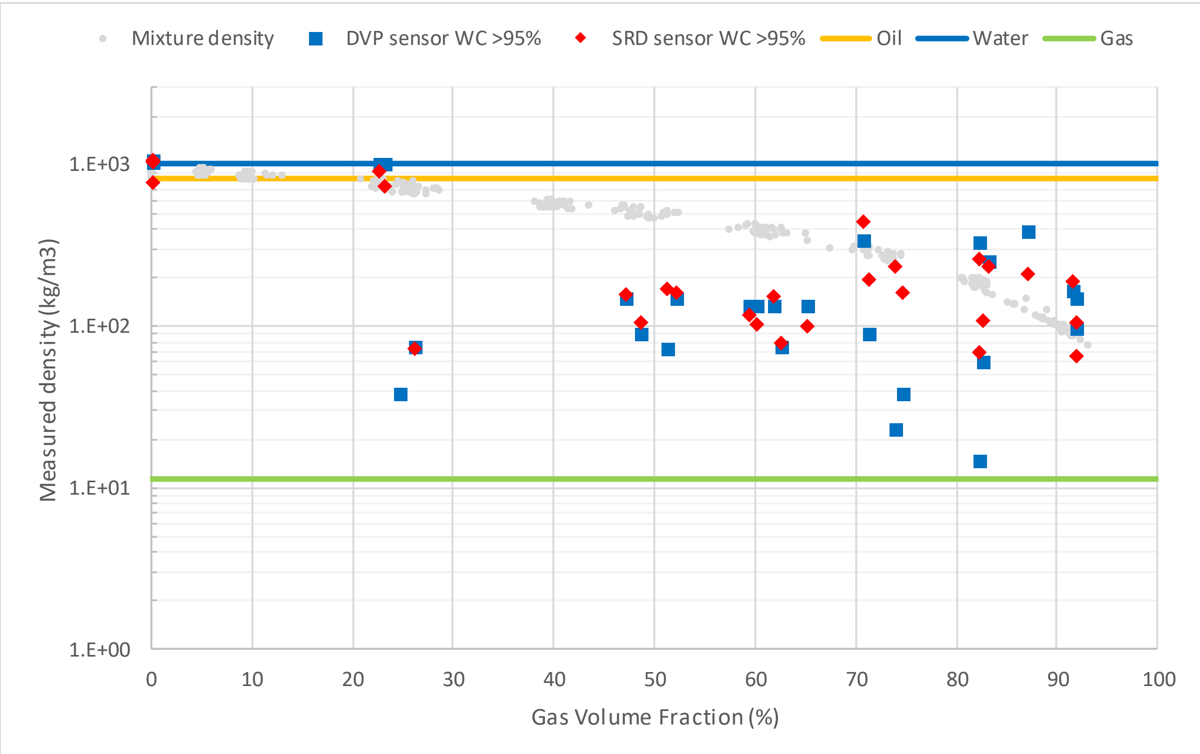


B1.8 Density Results for Water Cut 60-70%

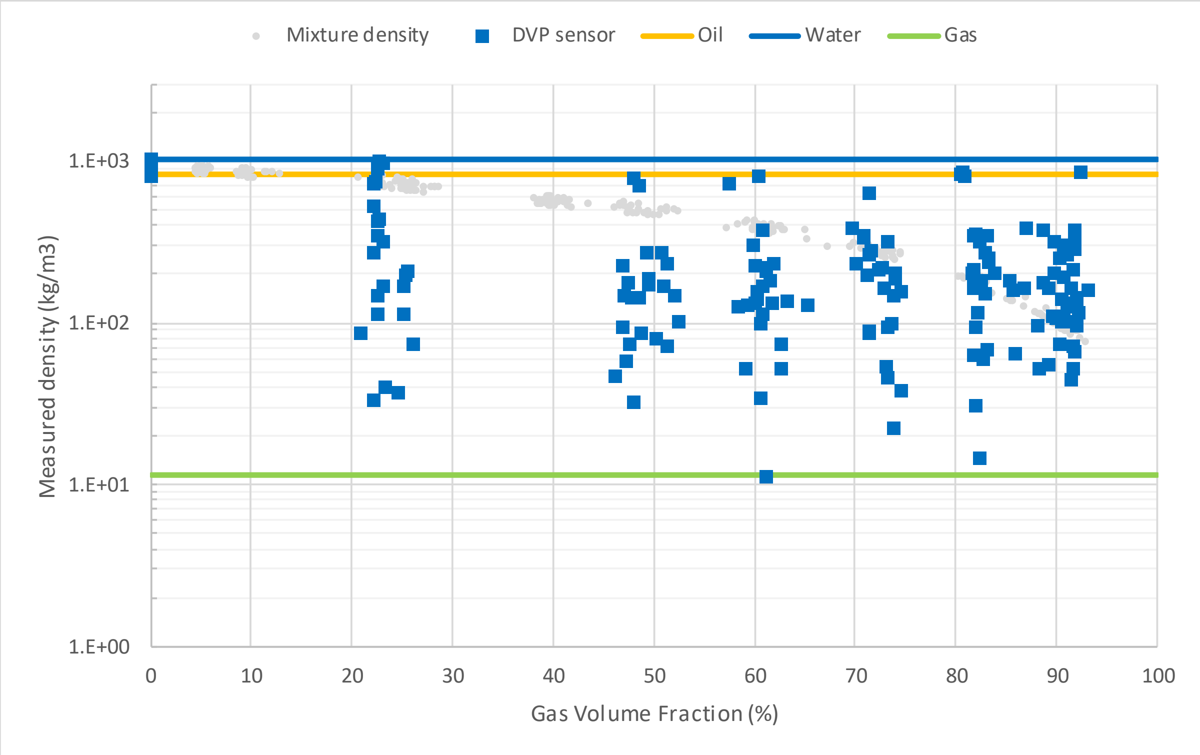


B1.9 Density Results for Water Cut 75-90%

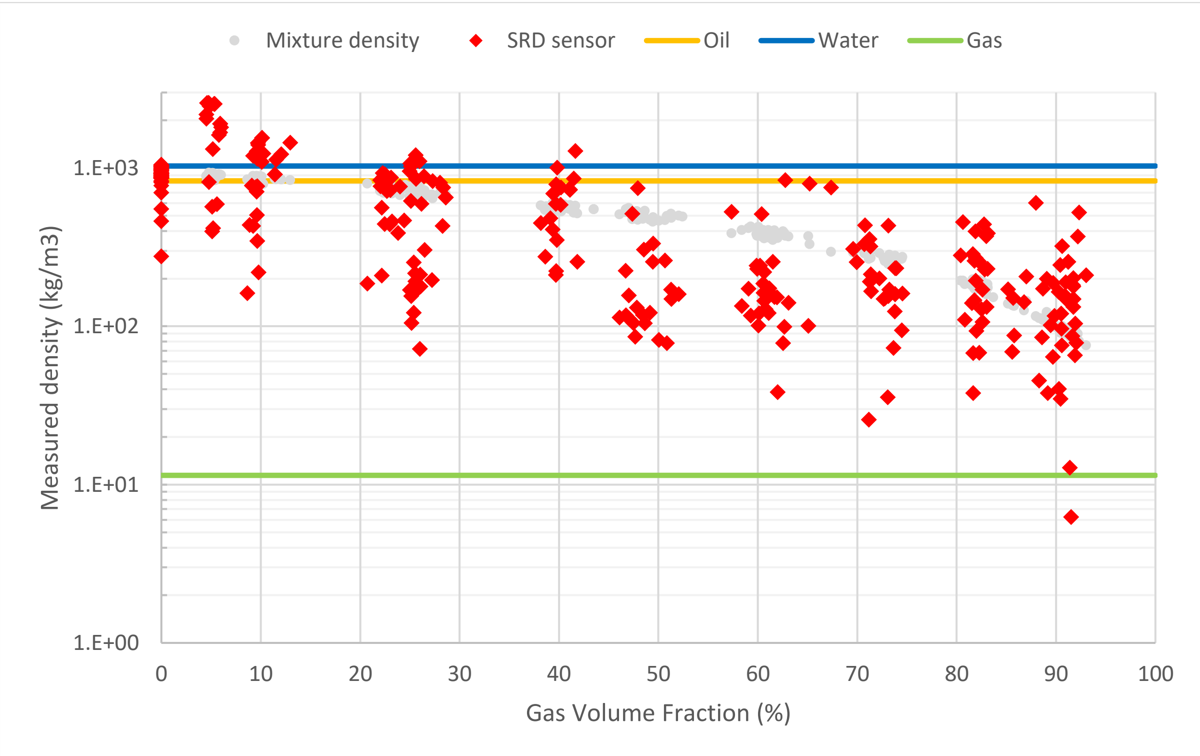
B1.10 Density Results for Water Cut >95%



B1.11 Density Results for DVP sensor at all Water Cuts

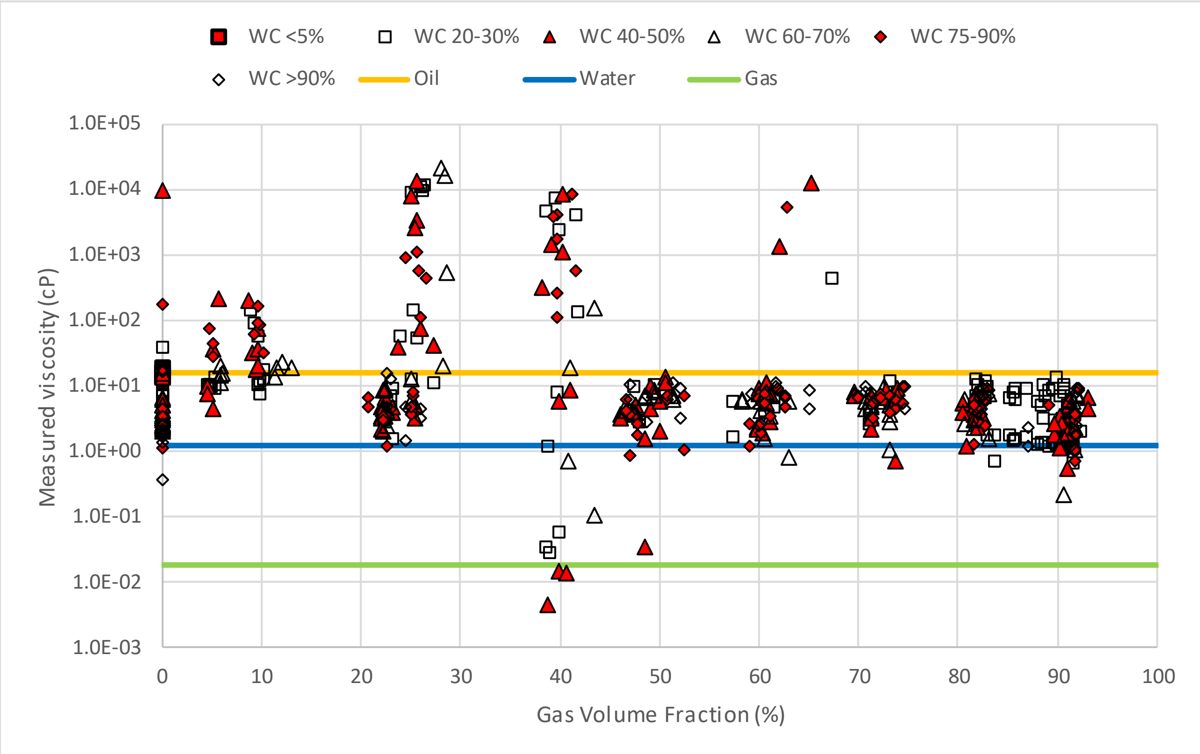


B1.12 Density Results for SRD sensor at all Water Cuts

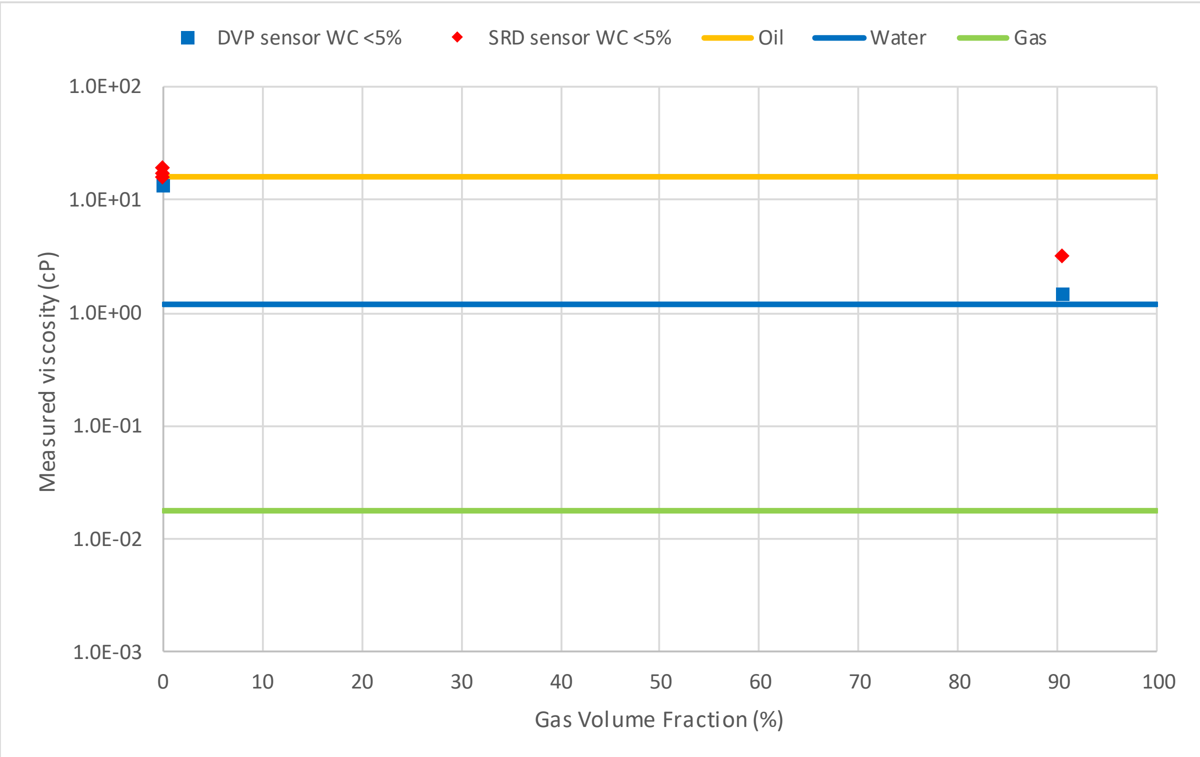


B.2 Viscosity Measurements

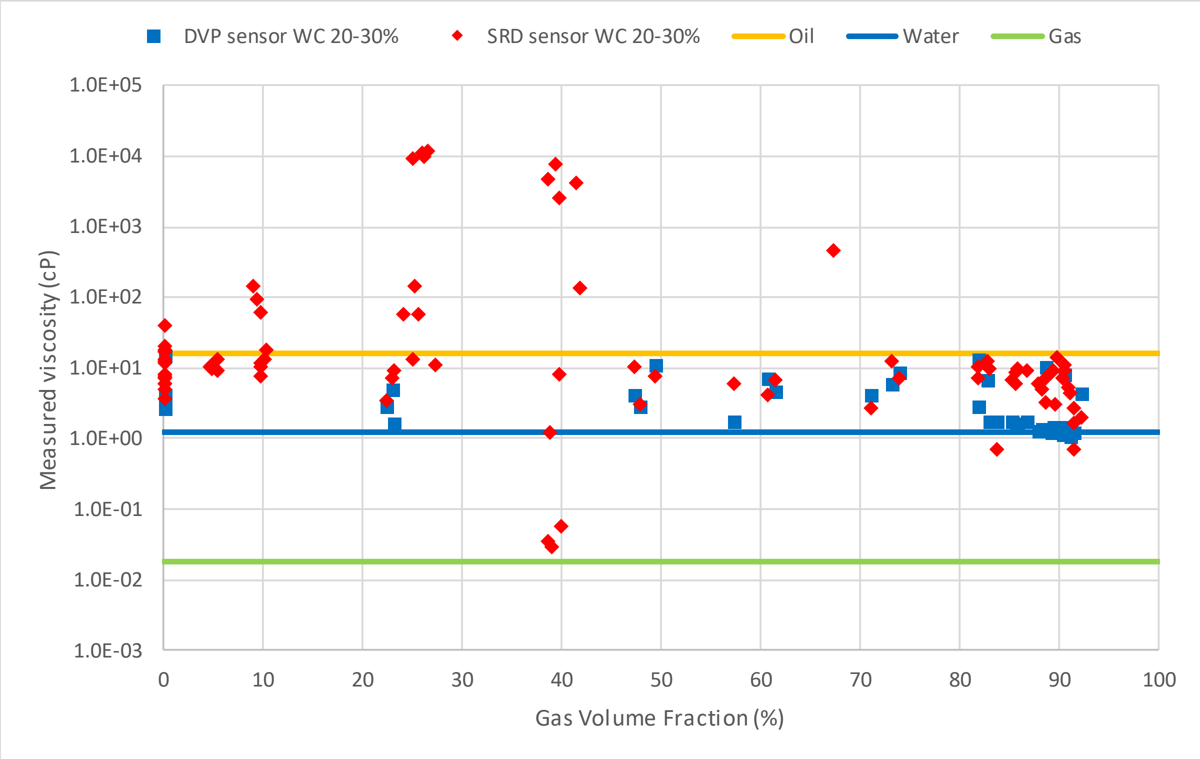
B2.1 All viscosity data for both sensors



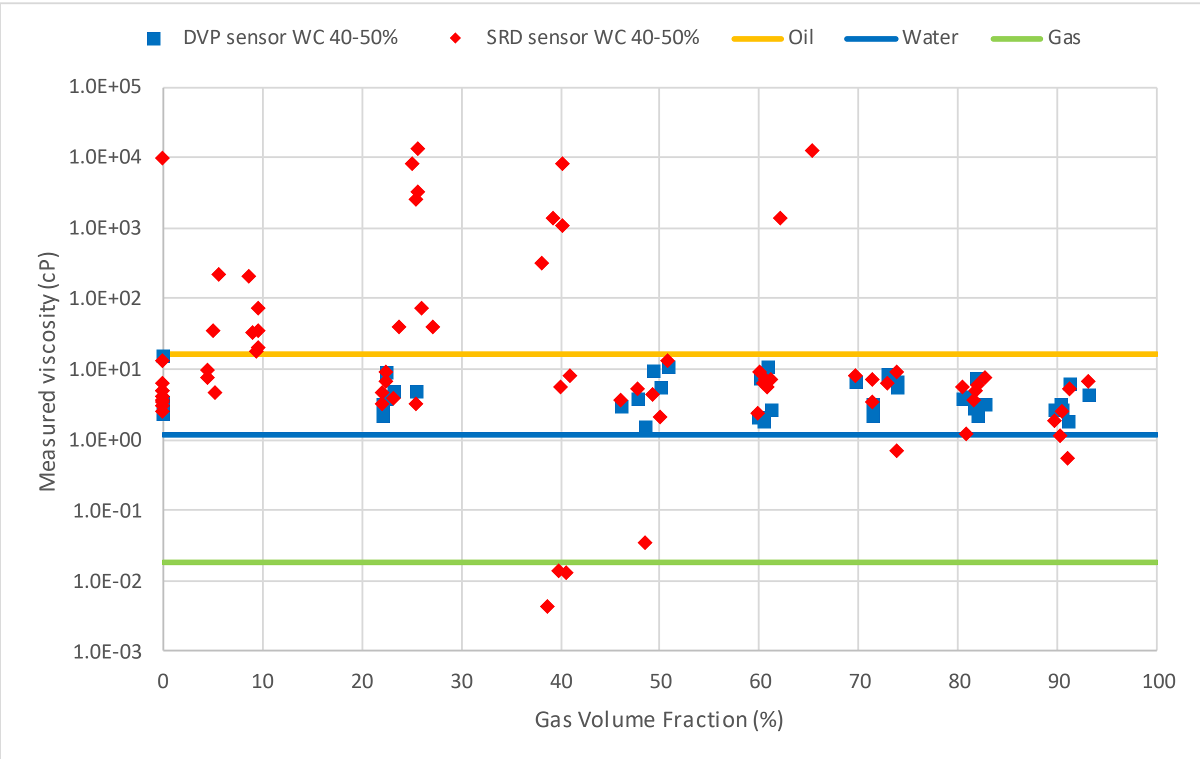
B2.2 Viscosity Results for Water Cut <5%



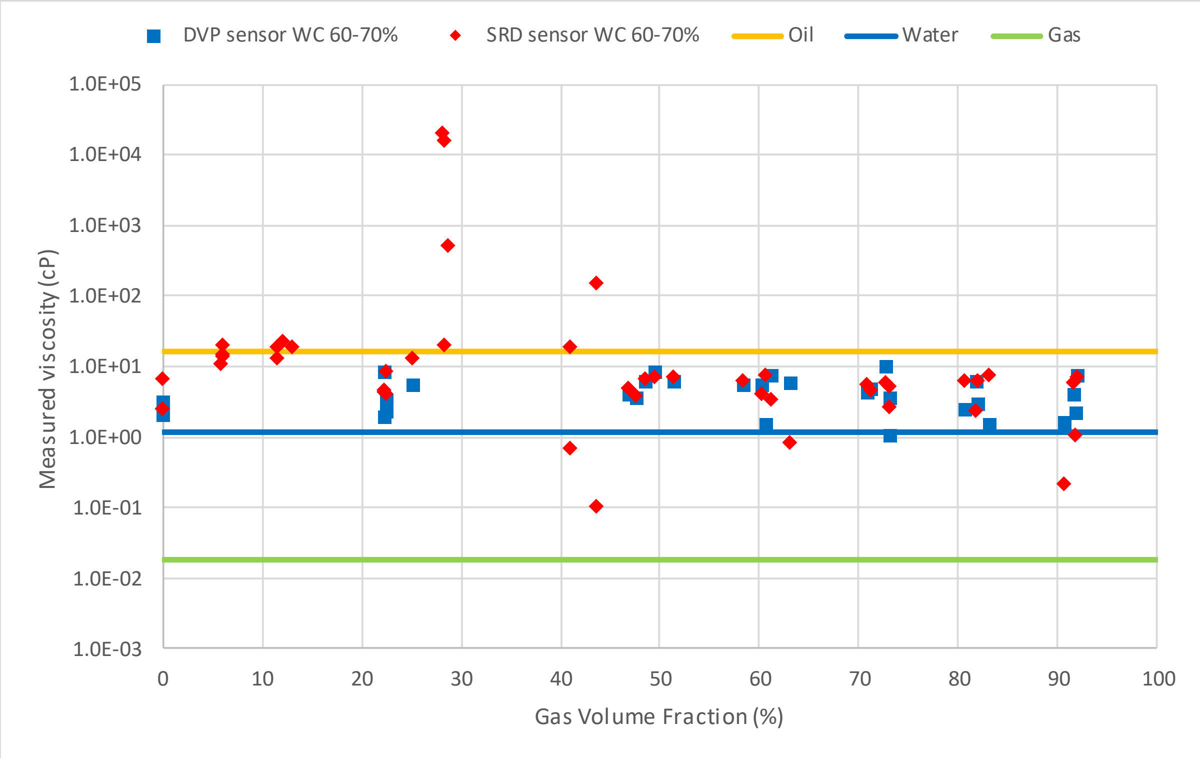
B2.3 Viscosity Results for Water Cut 20-30%



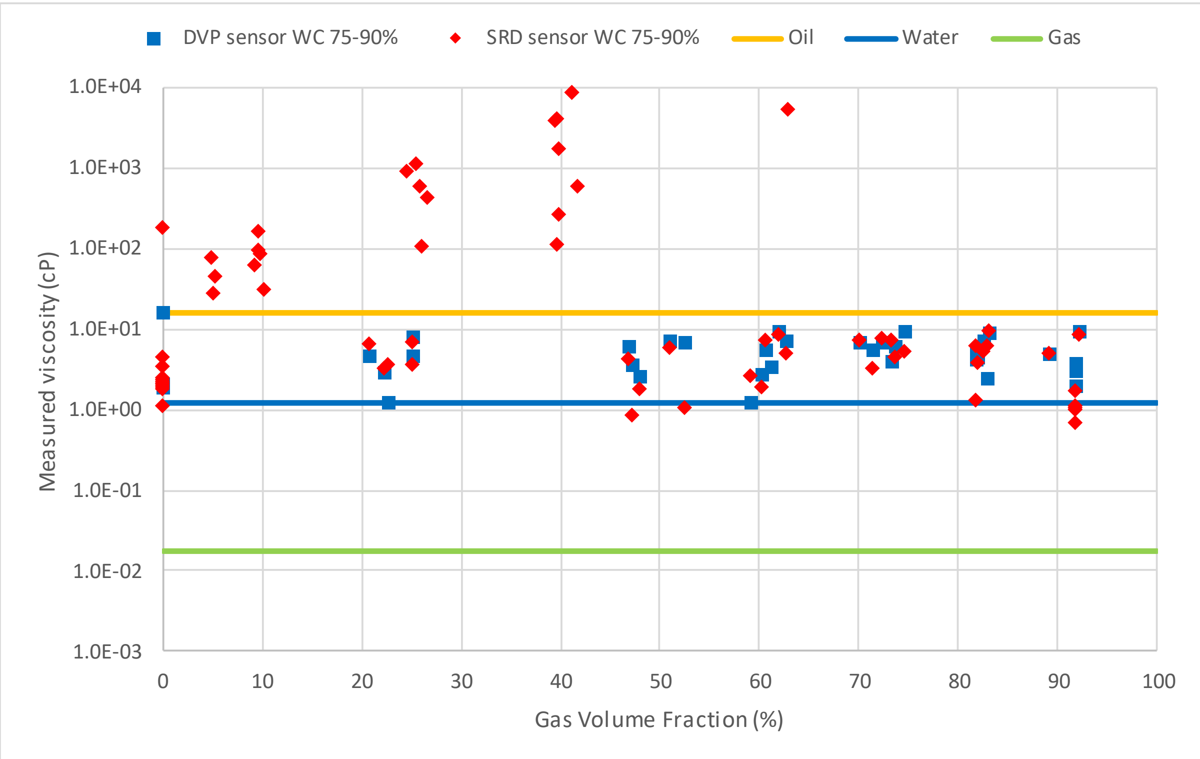
B2.4 Viscosity Results for Water Cut 40-50%



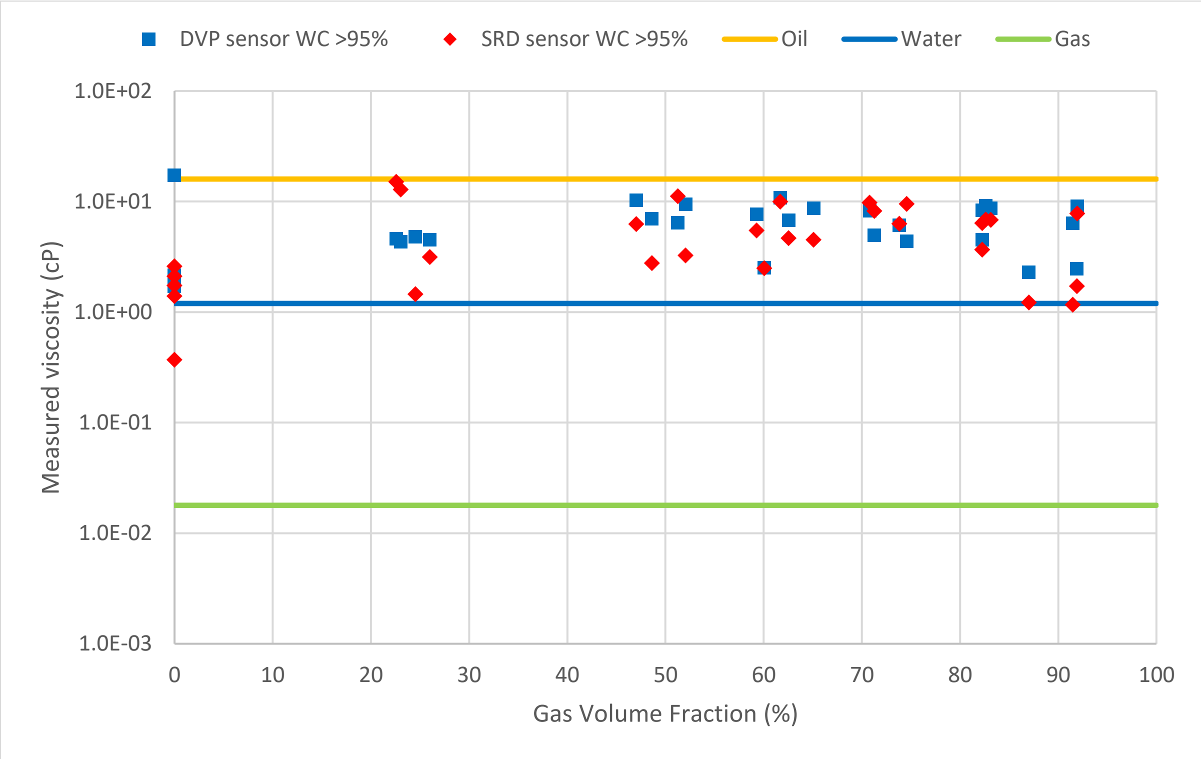
B2.5 Viscosity Results for Water Cut 60-70%



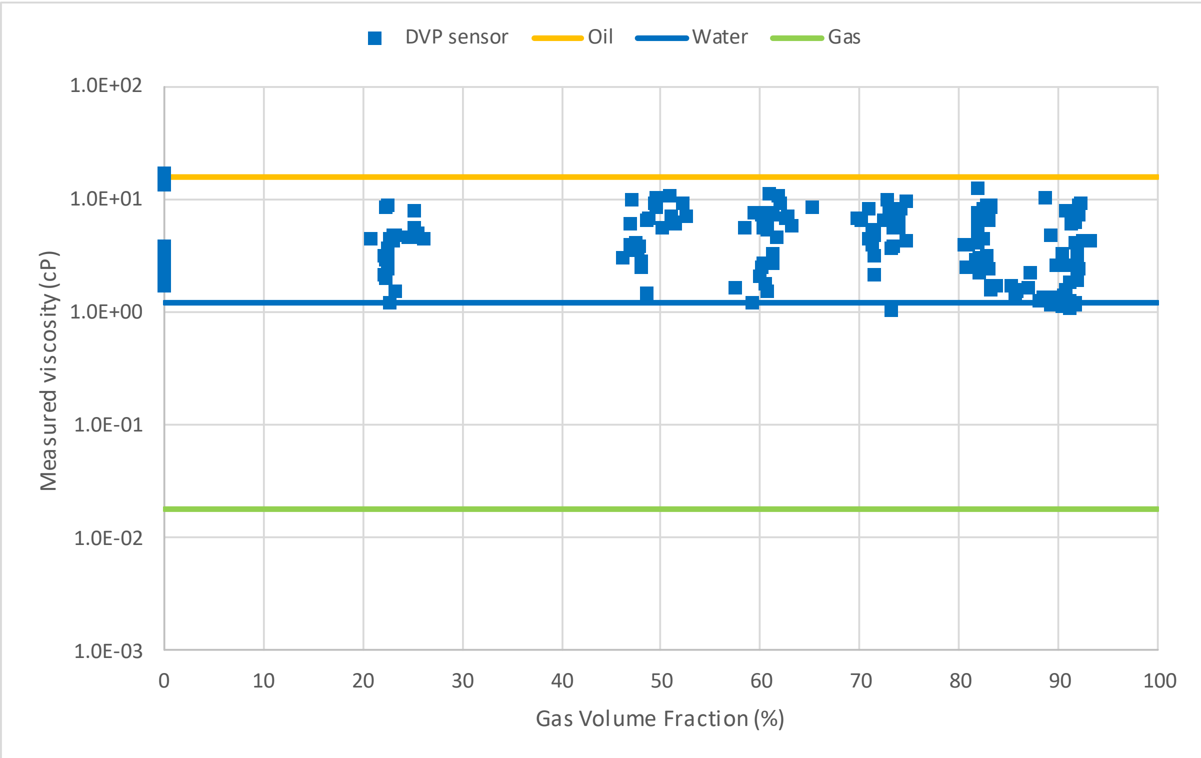
B2.6 Viscosity Results for Water Cut 75-90%



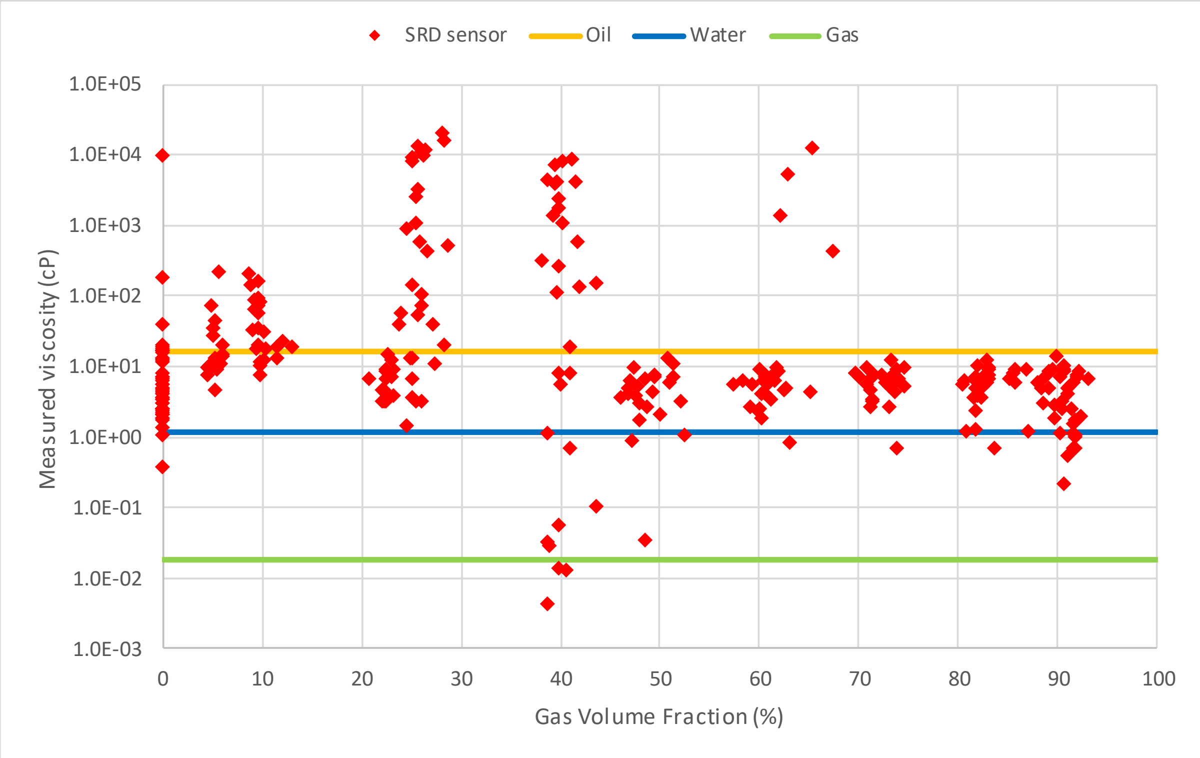
B2.7 Viscosity Results for Water Cut >95%



B2.8 Viscosity Results for DVP sensor at all Water Cuts

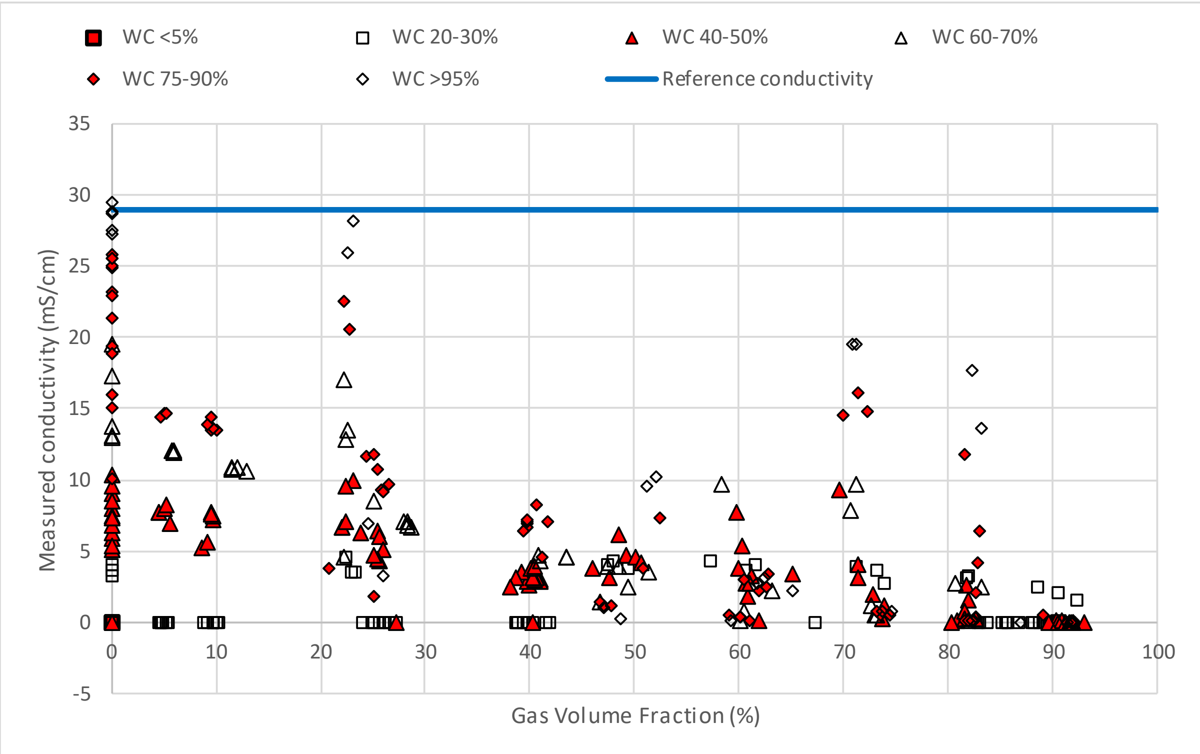


B2.9 Viscosity Results for SRD sensor at all Water Cuts

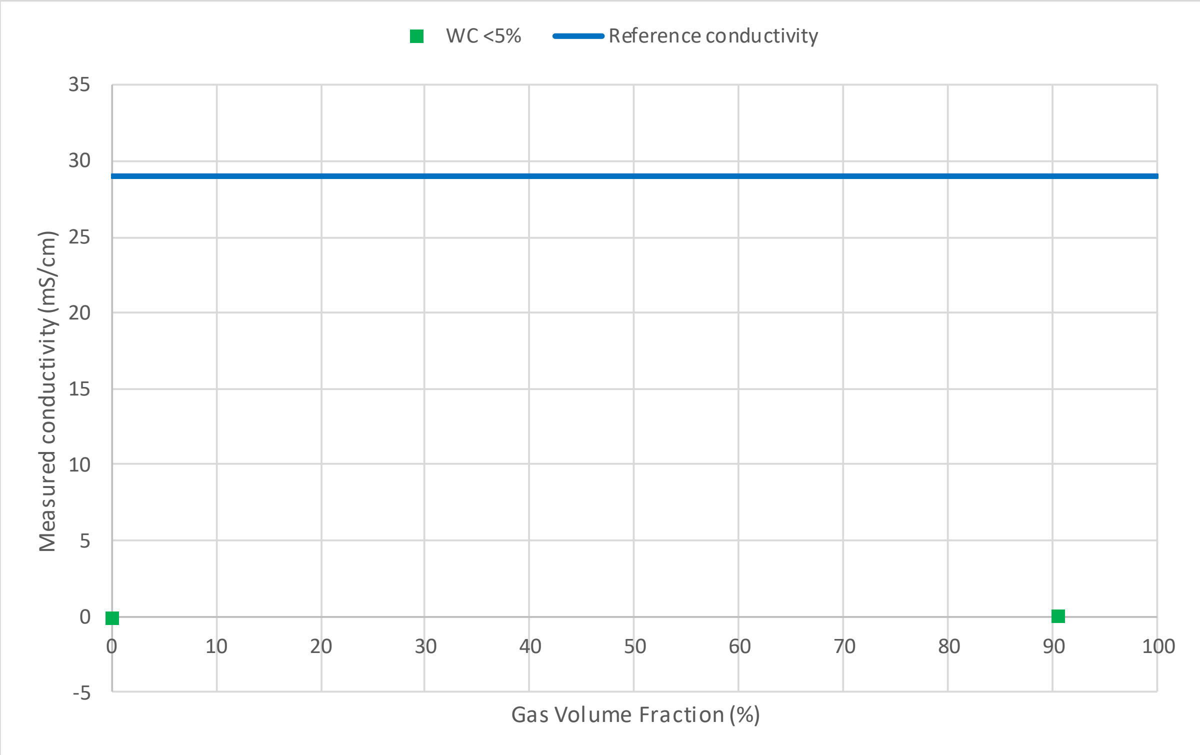


B.3 Conductivity Measurements

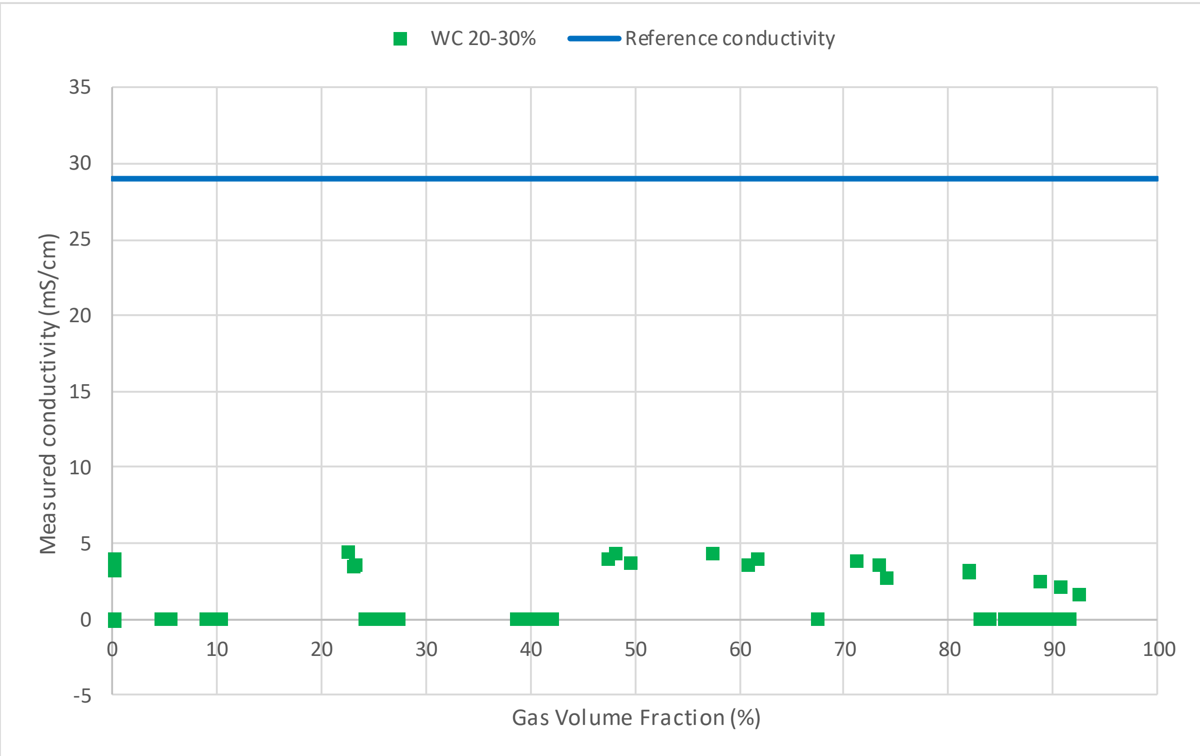
B2.1 All Conductivity Data



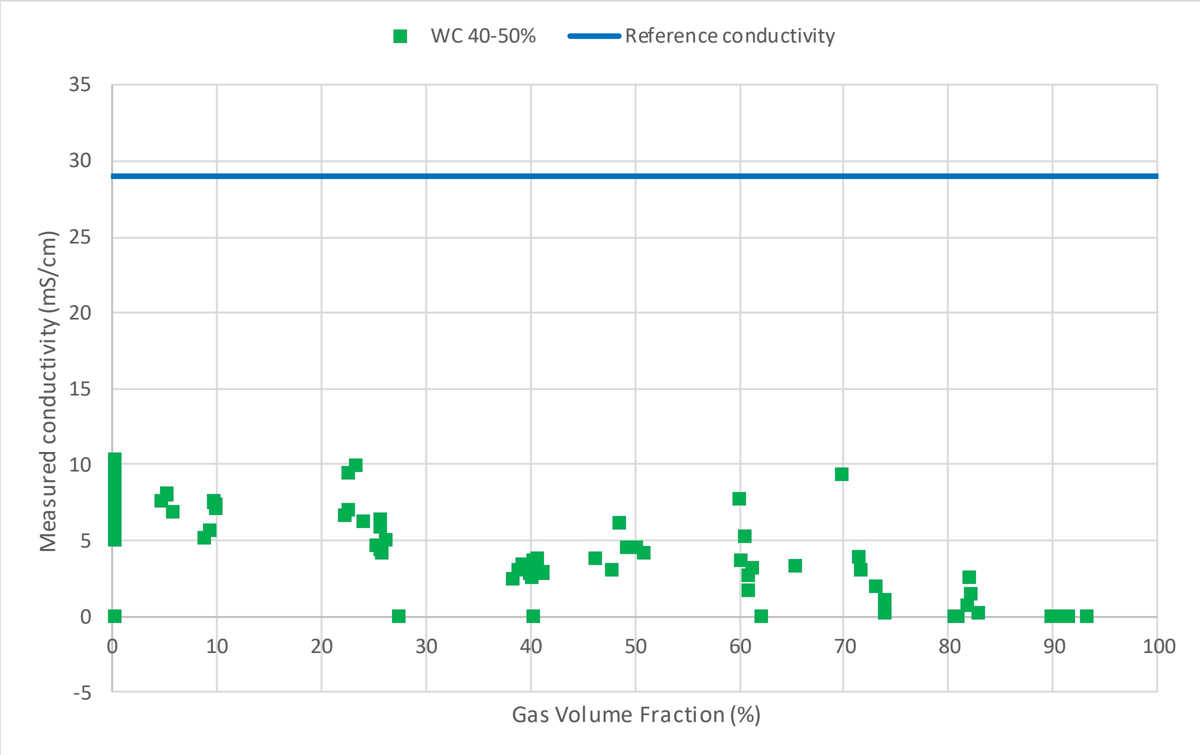
B2.2 Conductivity Results for Water Cut <5%



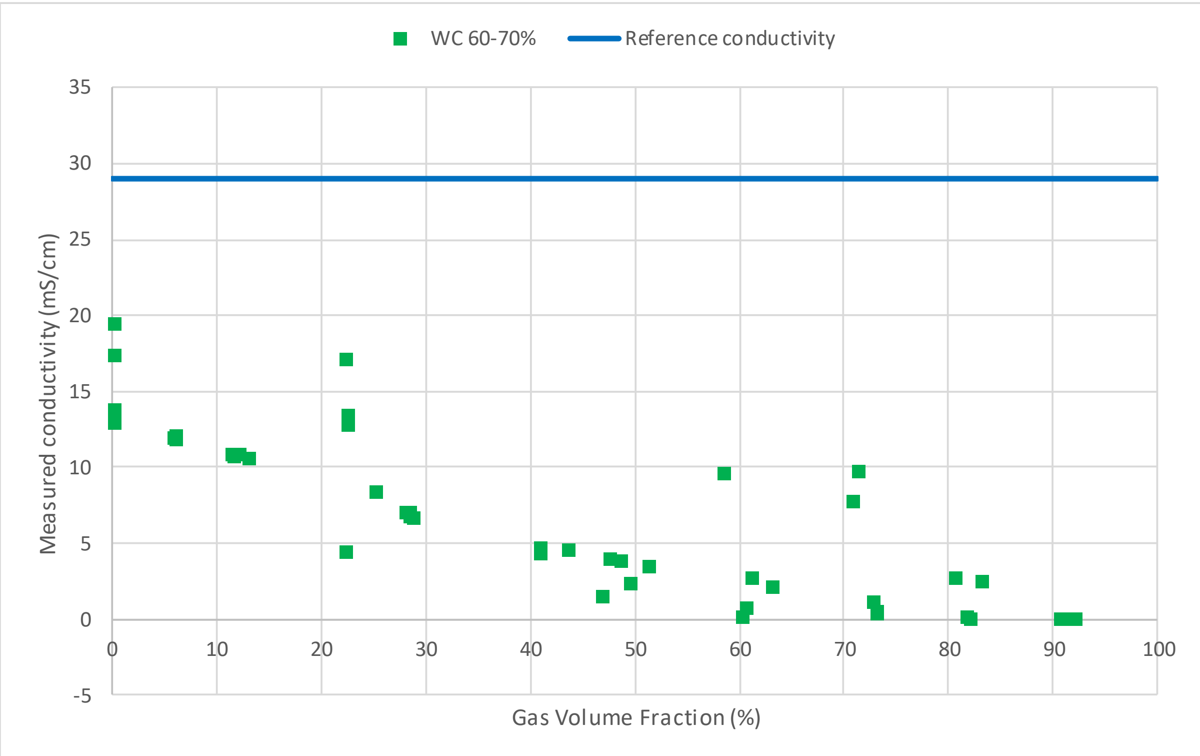
B2.3 Conductivity Results for Water Cut 20-30%



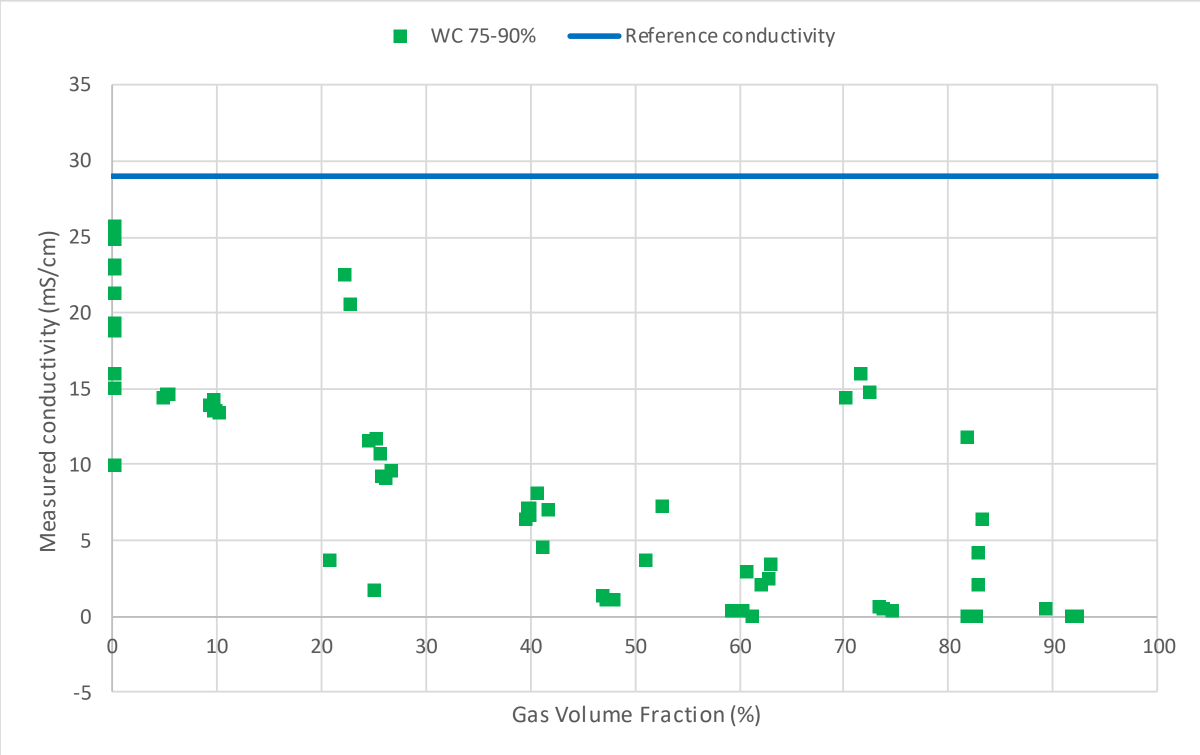
B2.4 Conductivity Results for Water Cut 40-50%



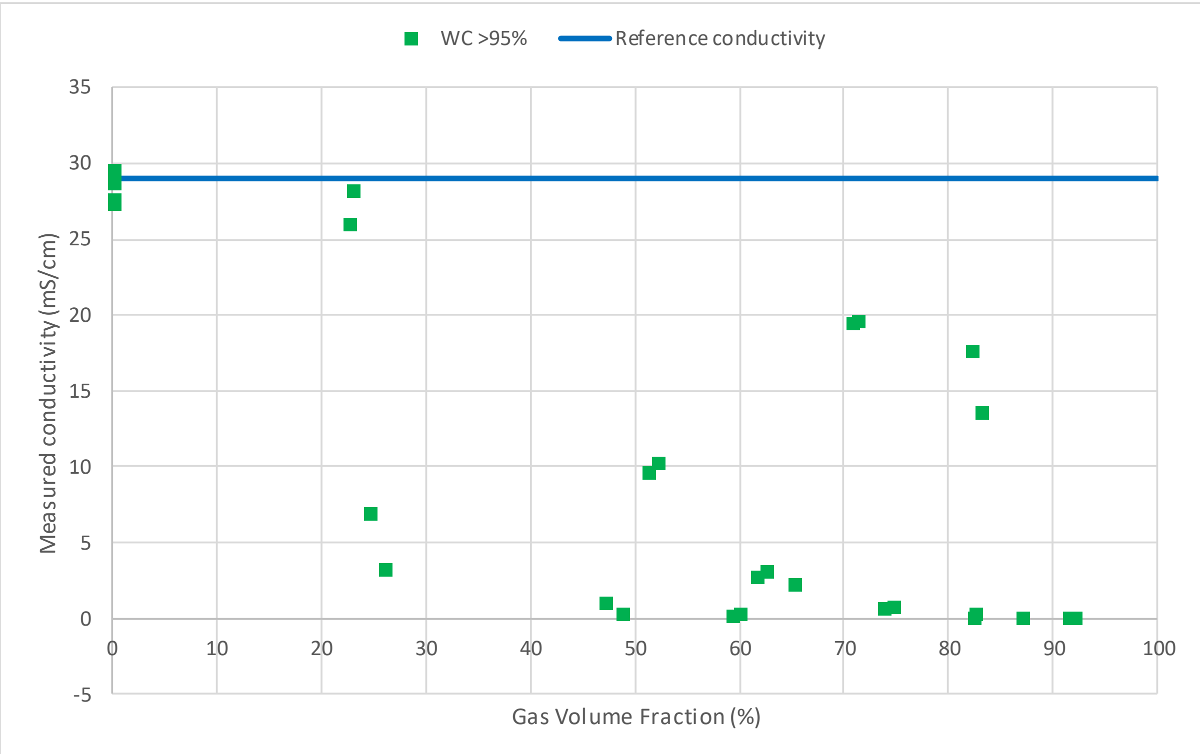
B2.5 Conductivity Results for Water Cut 60-70%



B2.6 Conductivity Results for Water Cut 75-90%



B2.7 Conductivity Results for Water Cut >95%



END OF REPORT

Partner with us today

TÜV SÜD National Engineering Laboratory

Point of contact: Sarah Jones

Tel: +44 (0) 1355 593700
Email: sarah.E.Jones@tuv-sud.co.uk

Web: www.tuv-sud.co.uk/nel