Information

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Revision History

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EXECUTIVE SUMMARY

Multiphase flow meters (MPFMs) are commonly used for well test, allocation and production management in the oil and gas industry. More recently these devices have been deployed for subsea or other challenging environments where they are not easily accessed. As a result, there is a growing need for validating the performance of these MPFMs in-situ.

One method identified, that can potentially offer a solution for in-situ verification of MPFMs, particularly when deployed in challenging environments, is the tracer dilution technique. The current study provides a review on the subject covering the following aspects:

- Applicable tracer dilution techniques
- Current and potential market for tracers and associated equipment
- Previous research work conducted, and patents filed
- Recommendations for future research

Tracer dilution techniques have been applied to check flow measurement both in the oil and gas, and geothermal industries. For most of the applications and studies done, manual spot sampling was used. These studies have shown some evidence that it may be sufficiently accurate to be used potentially as a traceable method to verify MPFMs in-situ.

Various tracer techniques have been used and investigated by end users and service providers. But data published from these investigations are thought to be of limited value. A search on patents filed on the subject has revealed that those involved in developing the techniques seem to anticipate the use of such a technique for MPFMs verification in situ in the future as both tracer chemistry and sensor developments advance.

It is recommended that a thorough cross-discipline scientific investigation to systematically assess the potential of the techniques to be conducted, given the emerging market interest and its current state of development. Potential avenues to consider:

- Flow loop testing
- Theoretical study of tracer diffusion and flow regime effect
- CFD analysis

Initially the aim should be to establish achievable phase flow rate measurement uncertainties, susceptibility to flow regime and rangeability. Subject to the outcome of this initial work, the concept of using tracer dilution techniques for MPFM verification is then developed to a Technology Readiness Level 2 (TRL 2) with practical issues of implementation under challenge environments investigated.
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<th>Description</th>
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<tbody>
<tr>
<td>BARC</td>
<td>Bhabha Atomic Research Centre</td>
</tr>
<tr>
<td>CFD</td>
<td>Computational Fluid Dynamics</td>
</tr>
<tr>
<td>DAQ</td>
<td>Data Acquisition System</td>
</tr>
<tr>
<td>ESMER</td>
<td>Expert System for Multiphase Flow Regime Identification and Metering</td>
</tr>
<tr>
<td>FAT</td>
<td>Factory Acceptance Test</td>
</tr>
<tr>
<td>FBA</td>
<td>Fluorinated derivatives of benzoic acid</td>
</tr>
<tr>
<td>GVF</td>
<td>Gas Volume Fraction</td>
</tr>
<tr>
<td>LDV</td>
<td>Laser Doppler Velocimetry</td>
</tr>
<tr>
<td>MMSCFD</td>
<td>Million Standard Cubic Feet per Day</td>
</tr>
<tr>
<td>MPFM</td>
<td>Multiphase Flow Meter</td>
</tr>
<tr>
<td>NIST</td>
<td>National Institute of Standards and Technology</td>
</tr>
<tr>
<td>PIV</td>
<td>Particle Image Velocimetry</td>
</tr>
<tr>
<td>PPM</td>
<td>Parts Per Million</td>
</tr>
<tr>
<td>PPB</td>
<td>Parts Per Billion</td>
</tr>
<tr>
<td>TRL</td>
<td>Technology Readiness Level</td>
</tr>
<tr>
<td>UKAS</td>
<td>United Kingdom Accreditation Service</td>
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</table>
2 INTRODUCTION

2.1 Background

There is a growing need for validating real-time monitoring of exceptionally complex multiphase flow in remote and inaccessible subsea applications. Process conditions can vary significantly, and extreme temperature and pressure can be prevalent along with varying water and oil ratio, gas volume fraction and solids content. Providing accurate flow measurement of the various components can prove to be challenging.

The issue is further complicated by the fact that subsea installations of multiphase flow meters (MPFMs) do not permit straightforward access and interrogation. Due to their hostile installation location, subsea meters cannot be simply removed and sent onshore for a ‘calibration’ at one of the multiphase flow facilities located around the world.

In-situ validation of MPFMs is critical to maintain confidence in the measured flow rates for end users. MPFMs can be essential for fiscal or allocation measurement, reservoir monitoring and for optimising the production from a well. A multiphase flow meter located in remote, subsea oil and gas production systems could be expected to perform accurately over the lifetime of the asset. Yet there is little information and few standardised procedures for performing MPFM in-situ validation.

Common practice for validating topside or subsea MPFMs prior to installation is via a Factory Acceptance Test (FAT) at a multiphase flow laboratory. These acceptance tests are often referred to as a ‘calibration’ and are typically agreed between the end user and the multiphase flow meter manufacturer. Test conditions at the FAT might not cover the entire operational range of the device as specified. This can be due to a lack of the capability of the available test facility, cost, time, unknown operational range or a combination of all the above. Typical acceptance criteria during an FAT are ±5% for liquid measurements and ±10% for gas measurements (k=1.64).

In terms of in-situ validation, a subsea or topside MPFM may be validated using a test separator by way of ‘well test’. However, a test separator might not always be available to a particular asset due to cost, location, installation complexities or a host of other reasons.

Another option is for the subsea MPFM to be compared with a topside MPFM. Again, this might not be a viable option depending upon the installation. In some circumstances, the production might be wholly subsea with no test separator to provide a validation of the production data. Furthermore, the subsea production could be part of a tie-back system to another development potentially owned and operated by a different oil & gas operator. This further highlights the importance of accurate measurements and in-situ verification of measurement devices.
The challenge for the oil and gas industry is to take the process of verification from laboratory and move it to ‘in-situ’. In essence, an ‘in-situ’ verification is a verification of flow meter performance that accounts for the environmental conditions and allows users to have ongoing confidence in the measurements.

One potential method of achieving this is through the use of tracer dilution techniques, in which a substance is injected into the flow and measured. This report will focus on reviewing tracer methods for their applicability in verifying MPFMs in subsea oil and gas applications.

2.2 NEL

NEL is an independent industrial research establishment specialising in 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 / research involving water, oil, gas, and multiphase flow measurement devices. All of the facilities are fully traceable to Primary National Standards and most are 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 operators and service companies among its clients. Consultancy work is carried out in a wide range of fields including multiphase and wet-gas applications; CFD modelling of fluid flow and erosion; uncertainty analysis of custody-transfer and allocation-metering systems; meter technology selection for a range of applications; meter system design and installation guidance etc.

2.3 Scope of Work

One method identified that can potentially offer a solution for in-situ verification for MPFMs deployed is the tracer dilution techniques. The current study provides a review on the subject covering the following aspects:

- Applicable tracer dilution techniques
- Current and potential market for tracers and associated equipment
- Previous research work conducted, and patents filed
- Recommendations for future research
3 TRACER BACKGROUND

3.1 General

The properties of a chemical compound in the fluid can be used as a chemical tracer, and characteristics such as temperature are physical tracers. Tracers may be artificially introduced, like dye tracers, or they may be naturally occurring such as radioactive materials.

Tracer methods are typically used where flow measurement or removal of flow measurement equipment for calibration is not possible due to e.g. size, time or a complex or inaccessible environment. Owing to typical uncertainty levels involved, tracer methods would normally be used to verify that a meter is operating within an acceptable tolerance rather than providing a traditional calibration. There are two main methods which are:

- Tracer dilution method
- Tracer transit time or Pulse method

These two methods typically involve the injection of a fluid which can be detected in the flow stream and used to measure the flowrate within the pipe. There are other techniques which use similar principles and have the potential for the measurement of multiphase flows.

- Particle Image Velocimetry
- Laser Doppler Velocimetry

3.2 Types of Tracers

Tracer is added either in a small batch or continuously, and its concentration or presence is monitored downstream. Although, in principle, any soluble material can be used as a tracer, in practice the main types of tracers are radioactive isotopes or fluorescent dyes.

3.2.1 Radioactive Isotopes

Radioactive materials have been considered as the best option since they can be detected in extremely low concentrations and in some cases the concentration may be detected without the need for sampling, depending on the type and equipment used.

The main difficulty however is having quantities of radioactive substances with high decay rates near pipelines, which can lead to environmental and personal hazard concerns. Also, to have relatively frequent measurements, large volumes of radioactive solutions would be necessary, and this presents considerable difficulties in installation, operation and maintenance, especially in challenging environments such as subsea.

One possibility is to generate radioactive tracer in situ. Potential tracers may be generated from substances that are naturally produced from the reservoir by techniques such as neutron irradiation. This approach has been used in production logging service.
Table 1 displays a list of some generic radioactive isotopes that are commonly used for tracer techniques.

**Table 1 – List of Typical Radioactive Isotopes for Tracer Measurements** [1]

<table>
<thead>
<tr>
<th>Radioactive Isotope</th>
<th>Abbreviation</th>
<th>Typical Half-life</th>
</tr>
</thead>
<tbody>
<tr>
<td>Iridium-192</td>
<td>Ir-192</td>
<td>73.8 days</td>
</tr>
<tr>
<td>Iridium-194</td>
<td>Ir-194</td>
<td>19.3 days</td>
</tr>
<tr>
<td>Scandium-46</td>
<td>Sc-46</td>
<td>83.81 days</td>
</tr>
<tr>
<td>Antimony-124</td>
<td>Sb-124</td>
<td>60.2 days</td>
</tr>
<tr>
<td>Antimony-122</td>
<td>Sb-122</td>
<td>2.7 days</td>
</tr>
<tr>
<td>Sodium-24</td>
<td>Na-24</td>
<td>14.96 days</td>
</tr>
<tr>
<td>Iodine-131</td>
<td>I-131</td>
<td>8.1 days</td>
</tr>
<tr>
<td>Bromine-82</td>
<td>Br-82</td>
<td>1.5 days</td>
</tr>
<tr>
<td>Cobalt-60</td>
<td>Co-60</td>
<td>5.3 days</td>
</tr>
<tr>
<td>Gold-198</td>
<td>Au-198</td>
<td>2.7 days</td>
</tr>
</tbody>
</table>

3.2.2 **Fluorescent Chemicals (dyes)**

Fluorescent chemicals are essentially standard dyes which produce fluorescence light when excited by an energy source (such as ultraviolet light). This allows devices such as fluorometers to be used to measure the amount of fluorescence which can be related to the concentration of the fluorescent dye.

Fluorescent dyes have been previously used in water systems due to their availability and non-hazardous nature. Care should be taken in Oil and Gas systems, as some organic compounds in produced hydrocarbons can also fluoresce.

Typically, fluorescent dyes used are: Amino G acid, Photine CU, Fluorescein, Lissamine FF, Pyranine, Rhodamine B, Rhodamine WT, and Sulpho rhodamine B [2][3].

3.2.3 **Fluorobenzoic Acids (FBA)**

Fluorinated derivatives of benzoic acid (FBA’s) are a type of aromatic compound which can be utilised as tracers. Table 2 lists types of FBA’s that are typically utilised.
Table 2 – List of Typical FBA Tracers [4]

<table>
<thead>
<tr>
<th>Chemical</th>
<th>Molecular Weight</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>2-Fluorobenzoic acid</td>
<td>140</td>
<td>C\textsubscript{7}H\textsubscript{5}FO\textsubscript{2}</td>
</tr>
<tr>
<td>3-Fluorobenzoic acid</td>
<td>140</td>
<td>C\textsubscript{7}H\textsubscript{5}FO\textsubscript{2}</td>
</tr>
<tr>
<td>4-Fluorobenzoic acid</td>
<td>140</td>
<td>C\textsubscript{7}H\textsubscript{5}FO\textsubscript{2}</td>
</tr>
<tr>
<td>2,3-Difluorobenzoic acid</td>
<td>158</td>
<td>C\textsubscript{7}H\textsubscript{4}F\textsubscript{2}O\textsubscript{2}</td>
</tr>
<tr>
<td>2,4-Difluorobenzoic acid</td>
<td>158</td>
<td>C\textsubscript{7}H\textsubscript{4}F\textsubscript{2}O\textsubscript{2}</td>
</tr>
<tr>
<td>2,5-Difluorobenzoic acid</td>
<td>158</td>
<td>C\textsubscript{7}H\textsubscript{4}F\textsubscript{2}O\textsubscript{2}</td>
</tr>
<tr>
<td>2,6-Difluorobenzoic acid</td>
<td>158</td>
<td>C\textsubscript{7}H\textsubscript{4}F\textsubscript{2}O\textsubscript{2}</td>
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</tr>
<tr>
<td>2,3,4-Trifluorobenzoic acid</td>
<td>176</td>
<td>C\textsubscript{7}H\textsubscript{3}F\textsubscript{3}O\textsubscript{2}</td>
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<tr>
<td>2,3,6-Trifluorobenzoic acid</td>
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<td>C\textsubscript{7}H\textsubscript{3}F\textsubscript{3}O\textsubscript{2}</td>
</tr>
<tr>
<td>2,4,5-Trifluorobenzoic acid</td>
<td>176</td>
<td>C\textsubscript{7}H\textsubscript{3}F\textsubscript{3}O\textsubscript{2}</td>
</tr>
<tr>
<td>2,4,6-Trifluorobenzoic acid</td>
<td>176</td>
<td>C\textsubscript{7}H\textsubscript{3}F\textsubscript{3}O\textsubscript{2}</td>
</tr>
<tr>
<td>3,4,5-Trifluorobenzoic acid</td>
<td>176</td>
<td>C\textsubscript{7}H\textsubscript{3}F\textsubscript{3}O\textsubscript{2}</td>
</tr>
<tr>
<td>2,3,4,5-Tetrafluorobenzoic acid</td>
<td>194</td>
<td>C\textsubscript{7}H\textsubscript{2}F\textsubscript{4}O\textsubscript{2}</td>
</tr>
<tr>
<td>Pentafluorobenzoic acid</td>
<td>212</td>
<td>C\textsubscript{7}HF\textsubscript{5}O\textsubscript{2}</td>
</tr>
</tbody>
</table>

Detection limits for FBA’s have been achieved previously down to 10 parts per billion in studies conducted for groundwater investigations [5]. These tracers have also been commonly used in studies related to geothermal and enhanced oil recovery applications [4] [5].

3.2.4 Other

A large number of other types of chemicals can also be used as a tracer, each depending on the specific fluid to be measured. A few of these types is listed below:

- Inorganic solutes
- Inert volatiles and gases
- Metal complexes
- Bacteriophages and microspheres

Limited information can be found in the public domain on these types of tracers in comparison to the ones listed in sections 2.1.1 to 2.1.3.
3.3 Applications

Potential applications for using tracers in the oilfield are great. Some of these applications are listed below:

- Single or Multiphase flow measurement
- Drilling muds
- Reservoir management
- Production logging
- Flare gas / Emissions monitoring
- Corrosion / Wear detection
- Leak detection
- Facility operations

Outside the oil and gas industry, tracers are commonly used within other industrial sectors.

- Medical / Biological
- Geological survey
- Waste water / sewage handling
- Nuclear

3.4 Market Summary

Table 3 shows a summary of the companies found during the research that either provide services using tracer techniques or manufacturers of tracer chemicals for the oil and gas industrial sector.
### Table 3 – Companies Offering Services Using Tracers

<table>
<thead>
<tr>
<th>Company</th>
<th>Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>TracerCo [6]</td>
<td>Multiple tracer services</td>
</tr>
<tr>
<td>SGS [7]</td>
<td>Multiple tracer services</td>
</tr>
<tr>
<td>Haelixa [8]</td>
<td>Reservoir Monitoring and product authentications</td>
</tr>
<tr>
<td>Resman [9]</td>
<td>Downhole tracer technology and tracer provider</td>
</tr>
<tr>
<td>Flow-tronic [10]</td>
<td>Flo-tracer dilution flowmeter</td>
</tr>
<tr>
<td>Spectrum Tracer Services [12]</td>
<td>Multiple tracer provider and RA tracing</td>
</tr>
<tr>
<td>Expro [13]</td>
<td>Petrotech MultiTrace</td>
</tr>
<tr>
<td>PetroKnowledge [14]</td>
<td>On-site tracer services</td>
</tr>
<tr>
<td>Schlumberger [15]</td>
<td>PERFORM Tracer Dyes</td>
</tr>
<tr>
<td>Turner Designs [16]</td>
<td>Fluorescent dyes and fluorometers</td>
</tr>
<tr>
<td>ThermoChem [17]</td>
<td>Multiple tracer services</td>
</tr>
<tr>
<td>Core Laboratories [18]</td>
<td>Reservoir / Drilling / Completion tracer services</td>
</tr>
<tr>
<td>Restrack [19]</td>
<td>Reservoir tracer services</td>
</tr>
<tr>
<td>Chemical Flooding Technologies [20]</td>
<td>Multiple tracer services</td>
</tr>
</tbody>
</table>
4 TRACER TECHNIQUES

4.1 General

As described previously, there are several techniques that utilise tracers for the measurement of flow. This section briefly describes the procedure of four techniques of interest and discusses their advantages and limitations. The techniques have been chosen as they are widely regarded as the most promising, easiest to implement and most reliable.

4.2 Tracer Dilution Technique

Tracer dilution is a technique where a tracer is injected into the pipe at a known rate. Assuming a constant flowrate in the pipe, after a period of time the concentration at a downstream position becomes constant and can be measured. This measured concentration can then be used along with the injection rate to determine the overall flow rate of fluid between the injection and downstream positions.

In this method, a tracer whose concentration can be measured accurately to low levels is important, as the method’s primary focus is the amount of dilution between the injection position and downstream concentration measurement point.

To determine the flow rate of the target fluid, equation 1 (rearranged in equation 2), derived from the conservation of mass, can be used [21].

\[ Q C_b + q C_1 = (Q + q) C_2 \]  
\[ Q = \left( \frac{C_1 - C_2}{C_2 - C_b} \right) q \]

- \( Q \) = Target fluid flow rate
- \( q \) = Injected flow rate of tracer
- \( C_b \) = Background concentration of tracer in the target flow stream
- \( C_1 \) = Concentration of injected tracer flow rate
- \( C_2 \) = Measured tracer concentration

For accurate results, the tracer must be sampled after sufficient mixing has taken place. Typically, the sample is taken at a distance downstream of the injection point where the variation in tracer concentration along the cross-sectional area of the pipe is below 0.5% [22]. Large static distances, such as 150 m [23], between injection and sampling point can also be used with the assumption that the fluids are fully mixed. Artificial mixing mechanisms can be used to reduce overall length of pipe required for complete mixing. This method can be utilised for both liquid and gas flows.
Figure 1 shows a simple set-up of a tracer dilution system, with the key components being:

- Tracer
- Meter to determine flow rate of tracer
- Detector of tracer concentration

The implementation in actual field conditions poses many challenges. For measurements of flow rate using the dilution method, factors such as injection rate, type of tracer, amount of tracer to be injected, mixing length for sufficient mixing of the tracer and dilution rates of injected tracer prior to measurement needs to be considered carefully before planning and conducting the tests.

In dilution methods the main source of error occurs in obtaining accurate determination of the tracer concentration in each fluid phase particularly if on-line determination is being used. However, it is noted that for sufficient mixing of the tracer in each phase, as close to homogenous flow conditions are preferred. Flow patterns such as slug or plug flow have been previously found to be a challenge for this method [24] [25].

4.3 Tracer Transit Time Technique

This method is similar to the tracer dilution technique, however, instead of utilising concentration as a method to determine overall flowrate, the actual presence of the tracer is monitored instead. The tracer transit time technique involves a pulse of tracer fluid being injected into the main line and the time taken for the tracer to pass between two detectors of known separation length measured. Thus, a velocity is determined from the length and time.

If the cross-sectional area of pipe between the two detectors is known, the volumetric flowrate of the target fluid can be estimated. In this method, radioactive isotopes with short half-lives have primarily been used owing to their relative effectiveness to be detected and having reduced health and environmental risks due to being below normal contamination limits [21].

The basic equipment arrangement for transit time techniques is shown in Figure 2. A tracer is injected into the process stream using an injection point. Two detectors are positioned sufficiently downstream of the injection point and as the tracer pulse passes the detectors, they respond to the presence of the tracer material and their output signals are sent to a data acquisition system. The time between the peaks of the response curves is the mean transit time of the tracer between the detectors, where the flow velocity is calculated. The linear
velocity can be converted to volume flowrate by multiplying it with the mean cross-sectional area of target pipeline.

*Figure 2 – Schematic of Simple Tracer Transit Time System* [26]

This method can be affected by flow regime [21][23] and flow profiles such as swirl can cause the peaks of the tracers to be difficult to determine leading to erroneous results. The application of tracers to multiphase flows indicates a number of potential issues with the methodology and subsequent measurements. For example, intermittent flow regimes such as slug flow are generally unsuitable for this method as the procedure assumes that a constant flow of each phase has passed during the time when the tracer is between both detectors. In addition, the velocity profile of each phase will not be uniform, this method essentially estimates a single velocity for all phases.

Another source of error comes from the uncertainty associated with the internal cross-sectional area of pipe between the two detectors. It is unlikely that this will be constant across the detectors and as such any deviations from the nominal pipe diameter will result in errors in the calculation of volumetric flowrate. In addition, the process conditions can influence the pipe geometry over time. For instance, some fluids have erosive or corrosive properties that may change the pipe diameter over time. If this is not accounted for the calculation errors will incur.

4.4 **Particle Image Velocimetry**

Particle Image Velocimetry (PIV) is a non-intrusive technique which can provide instantaneous velocity measurements in a cross-section of a flow. The technique can be used for both liquid and gas flow phases.

The target phase is seeded with tracer particles which are assumed to remain with the fluid and follow the fluid path. The velocity measurements are carried out by monitoring the motion of the tracer particles by taking two images in quick succession and determining the distance travelled by the particles. This initial calculation is described as the displacement field. The
velocity field is then determined by dividing the displacement field by the time between images [27].

A typical setup comprises of a camera, high power laser, an optical arrangement to convert the laser output light to a light sheet, tracer particles and a synchronizer as shown in Figure 3.

![Figure 3 – Schematic of PIV Set-up [27]](image)

The size of tracer particles used in PIV is important, smaller particles track the target fluid more closely, however if the particle is too small, the captured images will be difficult to analyse and cause mismeasurements. Any type of tracer particle can be used for PIV as long as it is able to scatter light and has similar physical properties to the target fluid. The greater number of particles used will give better velocity field measurements.

### 4.5 Laser Doppler Velocimetry

Similar to PIV, Laser Doppler Velocimetry (LDV) is a non-intrusive technique that can also be used to measure the instantaneous velocity of a target flow. The Laser Doppler Velocimeter sends a monochromatic laser beam toward the target and collects the reflected radiation.

LDV uses the Doppler Effect where the change in wavelength of the reflected radiation is a function of the targets relative velocity. Therefore, the velocity of the target can be obtained by measuring the change in wavelength of the reflected laser light, by creating an interference fringe pattern.
Again, similar to PIV, tracer particles that scatter light are injected into the target flow stream. However, in this case, a known frequency of laser light is used to illuminate the tracer particles in which the scattered light can then be detected by a photomultiplier tube. A photomultiplier tube is an instrument that generates a current proportional to absorbed energy of photons.

The difference between the incident and scattered light frequencies is called the Doppler shift. By analysing the Doppler-equivalent frequency of the laser light scattered by the tracer particles within the flow, the local velocity of the fluid can be determined.

**Figure 4 – Schematic of LDV Set-up [28]**
5 PREVIOUS RESEARCH WORK

5.1 Shell Design Procedure [23]

In 2008, Shell released a Design Procedure to standardise their methodology regarding flow rate measurement in wet gas environments. This utilises tracer dilution to determine the liquid content required in a wet-gas Venturi meter. The company has investigated and applied the technique in a number of gas-condensate fields [23].

The recommended procedure states the use of two fluorescent tracers, one for monitoring hydrocarbons and the other for water. Once injected and after sufficient mixing, a sample can be taken and analysed to determine the dilution ratio and therefore the liquid flow rates using equation 3. The concentration of tracer under line conditions can be determined with equation 4.

\[
Q_c = \left( \frac{c_i \cdot Q_t}{c_i} \right) - Q_t \approx \frac{c_i}{c_c} Q_t \quad c_c \ll c_i
\]

\[
Q_c = c_s \cdot Sh
\]

\[Q_c\] = Volume flow rate of target fluid  
\[Q_t\] = Injection flow rate of tracer  
\[c_i\] = Concentration of injected tracer  
\[c_c\] = Concentration of tracer under line conditions  
\[c_s\] = Concentration of tracer under standard conditions  
[\text{Sh}] = Shrinkage factor

The composition and density of the oil phase at line conditions can be drastically different in comparison to ambient conditions at which the tracer concentrations are often determined. The reason is that at ambient conditions, a high proportion of light hydrocarbons evaporate and as a result, the volume of the oil phase is less than at line conditions. Also, the temperature at process conditions is generally higher than ambient and the cooling can also cause further shrinkage. The amount of reduced volume is expressed as the Shrinkage Factor as shown in equation 5. This also happens for the water.

\[
Sh = \frac{Vol_{ac}}{Vol_{tc}}
\]

\[Vol_{ac}\] = Volume of target fluid at atmospheric conditions  
\[Vol_{tc}\] = Volume of target fluid at line conditions

As the tracer is not volatile, this shrinkage increases the fluorescence of the sample inversely proportional to the shrinkage and needs to be considered. There are three ways to account for the shrinkage: PVT calculations, the use of a pressurised sample container, or the use of a test separator.

The fluorescence generated by the tracer should be above the background fluorescence. This is to ensure that the signal noise ratio does not add uncertainty.

\[
\frac{\Delta f_{tr}}{f_{tr}} = f_{tt} \cdot \frac{\Delta Sh}{Sh} = \frac{f_{tt}}{f_{tr}} \cdot \frac{\Delta Sh}{Sh}
\]
The target liquid flow rate is calculated depending on the tracer injection flowrate which should be measured with low uncertainty to ensure overall uncertainty for the main flowrate is reduced. The design procedure states that use of a Coriolis meter and a control loop is sufficient for injection flowrate measurement.

5.1.1 Mixing Methodology

To ensure sufficient mixing of the tracer into the target fluid occurs between the injection point and downstream sample point, turbulent flows are required to ensure this can be achieved within acceptable distances. The Shell procedure states that the distance between tracer injection and sample point should be at least 150 pipe diameters. Stratified flow regimes and stagnant zones should be avoided.

If these flow regimes are likely to occur, mechanisms should be put in place to ensure that any liquid layers are mixed sufficiently. Static mixers can be utilised along with valves and bends to ensure mixing of the tracer into the target fluid.

5.1.2 Sampling procedure

Prior to the start of any test, Shell stipulated a minimum of 500 cm³ must be taken for each of the water and oil phases as control samples to determine their background fluorescence measurement. A similar volume of sample is also required for each tracer injected.

After commencement of the test, the design procedure states that sampling should not occur for at least 10 minutes to ensure stability. Thereafter, a minimum of 8 to 10 samples should be taken at 5 to 10-minute intervals.

5.1.3 Uncertainty

As long as the background fluorescence is relatively small, Shell claims the error in the flow rate measurement results can be estimated to be below 5 %, provided the Design Procedure is closely followed. Table 4 shows a summary of the expected uncertainties using the method described in the Shell’s Design Procedure.
### Table 4 – Uncertainty Estimations for Tracer Dilution Method [23]

<table>
<thead>
<tr>
<th>Uncertainty Source</th>
<th>Water</th>
<th>Condensate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection flow rate</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td>Dilution Ratio</td>
<td>1.5%</td>
<td>1.5%</td>
</tr>
<tr>
<td>Shrinkage</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td>Detector readings</td>
<td>0.7%</td>
<td>0.7%</td>
</tr>
<tr>
<td><strong>Total uncertainty</strong></td>
<td><strong>2.2%</strong></td>
<td><strong>2.2%</strong></td>
</tr>
</tbody>
</table>

The total uncertainties shown as achievable in Table 4 would form a good reference basis for *in-situ* multiphase meter or virtual meter verification and calibration.

### 5.2 Saudi Aramco – Field Testing Multiphase Meters [29]

Eight different types of flow meters were tested to measure multiphase flows by Saudi Aramco for uses on remote onshore locations and unmanned platforms. The objective of the study was to validate the accuracy of each meter and their reliability in multiphase conditions.

One of the meters tested under this program was a high-GVF Wet Gas metering skid. As a method to periodically confirm the calculated liquid rates, tracer dilution technology was also tested. The technique involved injecting fluorescent tracers into the flowline and subsequently collecting a sample at a suitable distance downstream from the injection point.

The method utilised was the same method as laid out in the Shell Design procedure as discussed in the section 4.1. The wet-gas meter was evaluated at gas rates from 20 to 57 MMSCFD, with 1.5 to 6% liquids by volume. Tracer dilution technology tests were reported to be successful in determining both liquid phase flow rates to within ±15% in comparison to the conventional test-traps utilised, however no confidence level for this uncertainty was stated.

It was also reported that Saudi Aramco had plans to install Venturi systems on most new gas development wells with the tracer-dilution technique being periodically utilised to validate liquid flow rates.


The Expert System for Multiphase Flow Regime Identification and Metering (ESMER) is a multiphase meter that learns from operation rather than using conventional fluid mechanic models. In 1997, a field test was carried out where the ESMER was installed on the Shell Auk Platform as part of a field trial to validate the technology using a test separator and also tracer techniques.
Tracer flow measurements were carried out to determine reference flow rates using a service company. Two types of fluorescent dyes were used, one dye is soluble only in oil, the other in water only. The injection occurred for 100 to 120 minutes and required 100 pipe diameters between injection and sampling points to ensure sufficient mixing. A shorter distance was also used, which included pipe bends, and was considered suitable.

### Table 5 – Number of Samples for Each Test Parameter [24]

<table>
<thead>
<tr>
<th>Date/Time 1 May 1998</th>
<th>Production Condition as % of Operational Flow</th>
<th>Number of Separator Samples</th>
<th>Number of ESMER Samples</th>
<th>Number of Tracer Samples</th>
</tr>
</thead>
<tbody>
<tr>
<td>12:00 - 15:00</td>
<td>100%</td>
<td>3</td>
<td>52</td>
<td>10</td>
</tr>
<tr>
<td>15:00 - 16:30</td>
<td>Stabilisation time</td>
<td>-</td>
<td>24</td>
<td>-</td>
</tr>
<tr>
<td>16:30 - 19:00</td>
<td>75%</td>
<td>4</td>
<td>33</td>
<td>10</td>
</tr>
<tr>
<td>19:00 - 20:00</td>
<td>Stabilisation time</td>
<td>-</td>
<td>7</td>
<td>-</td>
</tr>
<tr>
<td>20:00 - 22:00</td>
<td>50%</td>
<td>6</td>
<td>38</td>
<td>-</td>
</tr>
</tbody>
</table>

Samples were collected at 10-minute intervals for a 90-minute trial period. Samples were given 3 to 4 hours separation time and then analysed under fluorescent light to determine amount of dye in each phase. Results from the trial are summarised in Table 6.

### Table 6 – Average Deviation between ESMER vs Tracer [24]

<table>
<thead>
<tr>
<th>Ref</th>
<th>Date/Time 29 Apr 1998</th>
<th>Production Condition as % of Operational Flow</th>
<th>Deviation (ESMER-Tracer)/ESMER*100% Oil flowrate</th>
<th>Deviation (ESMER-Tracer)/ESMER*100% Water Cut</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>13:45-15:15</td>
<td>100%</td>
<td>-6.3%</td>
<td>-3.2%</td>
</tr>
<tr>
<td>B</td>
<td>17:00-18:30</td>
<td>75%</td>
<td>17.4%</td>
<td>-7.8%</td>
</tr>
</tbody>
</table>
Problems and issues were experienced with the tracer technique when certain flow regimes, such as slug flow, occurred. To make this technique work, it requires as close to homogeneous conditions as possible. No tracer was considered for measurement of gas during this study.

5.4 Bhabha Atomic Research Centre (BARC) (2017) – Development and Application of Radiotracer Dilution Technique for Flow Rate Measurements [25]

In 2017 the Isotope and Radiation Application Division of BARC released an article on the use of radiotracer dilution as a technique for flow measurement. The paper explains the principle, as shown in Figure 6, and detailed steps required to use this technique.

![Figure 6 – Principle of Tracer Dilution Technique][25]

The steps listed include: radiotracer selection, determination of amount of tracer required, injection of tracer, monitoring of downstream concentration, sample collection, sample measurement and finally determination of flow rate of the target fluid.

One of the most important steps is the selection of a suitable radiotracer which has the correct characteristics for a given application. Typical radiotracer characteristics to be noted are half-life time, type and energy of radiation, availability, specific activity and radiotoxicity. However, for online monitoring, the radiotracer is required to be gamma-emitting and to a sufficient activity level to be detected. Due to the hazardous nature of radioisotopes, characteristics such as half-life need to be carefully considered to ensure it is long enough to complete the measurements, but short enough to minimise exposure to surroundings.

This radiotracer dilution method was employed in two 3.6 m diameter pipelines at a power plant in India, used to transport sea water for cooling as shown in Figure 7.
For this application, Iodine-131 as sodium iodide was selected; the mixing length required was about 140 times the diameter of the pipeline as per ISO 2975. In the present case the sampling location, which was 1500 m away from the tracer injection point, was larger than the minimum mixing length required (504 m).

A challenge found was that the injection sample cannot be directly measured due to its high concentration. Hence the dilution of the collected aliquot was required before its measurement. To avoid the loss of radiotracer and to minimize the error due to dilution, a multistep dilution procedure was adopted as shown in Figure 8.

**Figure 7 – Schematic of Tracer Application** [25]
Error in the measurement of total flow rate was determined to be largely due to error in the measurement of injection rate of the tracer and the measurement of radiotracer concentration. Uncertainty contributions from individual parameters were estimated and subsequently, the uncertainty in the total measurement was estimated using equation 7.

$$\sigma_{Q_2} = \sqrt{\left(\frac{\sigma_{Q_1}}{Q_1}\right)^2 + \left(\frac{\sigma_C}{C_1}\right)^2 + \left(\frac{\sigma_C}{C_2}\right)^2}$$

- $Q_1$ = Injection rate of the tracer
- $Q_2$ = Target fluid flow rate
- $C_1$ = Concentration of injected radiotracer
- $C_2$ = Concentration of collected radiotracer sample
- $\sigma_{Q_1}$ = Measurement error of Injection rate of the tracer
- $\sigma_{Q_2}$ = Measurement error of target fluid flow rate
- $\sigma_{C_1}$ = Measurement error of injected radiotracer concentration
- $\sigma_{C_2}$ = Measurement error of collected radiotracer concentration

The uncertainty in the measurement of flow rates in four different tests was estimated using the above equation and were found to be ~3.0%. The summarised results and their associated uncertainties from the experiment are shown in Table 7.
Table 7 – Results of Flow Rate Measurements\,[25]

<table>
<thead>
<tr>
<th>Equipment Location</th>
<th>( Q ) (ml/min)</th>
<th>( C_1 ) (counts/2 min)</th>
<th>( C_2 ) (counts/2 min)</th>
<th>( Q ) (m(^3)/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit-1, Pump A</td>
<td>188.2</td>
<td>( 5.867 \times 10^{10} )</td>
<td>11875</td>
<td>15.43 ± 0.46</td>
</tr>
<tr>
<td>Unit-1, Pump A + B</td>
<td>187.2</td>
<td>( 3.755 \times 10^{10} )</td>
<td>4240</td>
<td>27.51 ± 0.82</td>
</tr>
<tr>
<td>Unit-2, Pump A</td>
<td>220.8</td>
<td>( 3.096 \times 10^{10} )</td>
<td>8044</td>
<td>14.10 ± 0.43</td>
</tr>
<tr>
<td>Unit-2, Pump A + B</td>
<td>185.1</td>
<td>( 6.626 \times 10^{10} )</td>
<td>8291</td>
<td>24.55 ± 0.78</td>
</tr>
</tbody>
</table>

Flow meters which were originally installed in the pipelines differed in results to the tracer dilution tests. Subsequent investigations found that the flow meters were malfunctioning and after repair and recalibration, the flow meters agreed with the tracer results, however details of the calibration and validation were not given.

The paper shows that use of the tracer dilution method for this application was successful, however, data from recalibrated flowmeters was not included which would verify this result.

5.5 Malaysian Nuclear Agency - Flow Rate Measurement in Multiphase Flow Rig: Radiotracer and Conventional\,[30]

A radiotracer, Molybdenum-99 was utilised to study the flow rate in a multiphase facility by the Malaysian Nuclear Agency. The multiphase facility consists of a 58.7 m long and 0.20 m diameter pipeline that holds up to 0.296 m\(^3\) of total liquid. The study consisted of using typical flow meters and compared the results with the chosen radiotracer using the total count method, a form of the tracer transit time technique. Even though the experiment was trialled in a multiphase facility, only single-phase water was utilised for the trial.

The facility consisted of pumps, flow meters, regulating valves, a test section and a liquid storage separator, which was designed to study different multiphase measurement techniques. A portable Doppler FD-400 ultrasonic flow meter was used alongside a Coriolis and turbine meter to measure the flow rate in the pipelines.
Before the start of the test, Rhodamine dye was injected for leak detection purposes and to estimate the injection time required to ensure a sufficient pulse was detected downstream. The total count method requires that the time the tracer takes to travel be monitored with high precision. Therefore, the time on the Data Acquisition system had to align with the injection time to ensure errors were not introduced.

Figure 10 shows an example of the time taken from injection of the tracer to the tracer being detected downstream at a detection point. The results from this experiment are summarised in Table 8.
Table 8 – Summary of Comparison Results [30]

<table>
<thead>
<tr>
<th>No.</th>
<th>Techniques</th>
<th>Equipment</th>
<th>Volumetric flow rates, Q (m³/h)</th>
<th>Error (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Coriolis meter</td>
<td>Flow meter</td>
<td>17.4</td>
<td>Reference</td>
</tr>
<tr>
<td>2</td>
<td>Doppler flow meter</td>
<td>Flow meter</td>
<td>17.7</td>
<td>1.7</td>
</tr>
<tr>
<td>3</td>
<td>Turbine meter</td>
<td>Flow meter</td>
<td>17.0</td>
<td>-2.2</td>
</tr>
<tr>
<td>4</td>
<td>Total count method</td>
<td>Radiotracer</td>
<td>17.1</td>
<td>-1.9</td>
</tr>
</tbody>
</table>

The results show that this tracer technique has been successful in the measurement of a single flow in comparison to traditional flow measurement techniques, with errors ranging from 1.7 to -2.2%. It should also be noted that the study confirms that the total count method was repeatable and reliable for this application. However, similar to other research work, this experiment only focussed on water.

5.6 CEESI – Flow Measurement Uncertainty Using Tracer Gas Dilution Method [31]

In 2011, a blind study was completed by Chevron to validate the use of different techniques for flare gas flow measurement. The objective was to improve current guidance, such as:

- API-14.10 (Measurement of Flow to Flares)
- API-22.3 (Testing Protocol for Flare Gas Metering)

The experiment included multiple path USM’s, an optical flow meter and a tracer gas dilution technique. The tracer gas selected for the experiment was Sulfur Hexafluoride (SF₆).

Figure 11 – Tracer Injection Set-up at CEESI Facility [31]

The testing was carried out at CEESI’s laboratory using air through a test section of 10-inch piping in a horizontal configuration, with velocities up to 45 m/s. Several notable observations were made during the project [31]:

- As expected, better mixing was achieved with more bends in the test section.
• The injection flow rate of the tracer constitutes a large part of the overall uncertainty.
• The uncertainty in flowrate of the calibration gas must be considered in the uncertainty calculations.
• Because concentration determination via sampling is a discrete single point measurement, large random errors are likely; so many samples are required to reduce random error.
• How well the tracer gases mix are hard to characterise.

The tracer gas dilution method error was found to be between -10 and 6% based on comparison with the gas flow rate reference measurement.

![Figure 12 – Percent Error vs. Velocity for Tracer Gas Dilution Method][31]

Overall uncertainty was estimated to be 8.3% using equation 8. This equation can be broken down into; Bias errors, Gas analyser uncertainty and random error due to the thermal mass meter (used to measure the injection rate of tracer gas).

\[
\frac{\partial T_F}{F_U} = \sqrt{\left[ \left( \frac{\Delta C_D}{C_I} \right)^2 + \left( \frac{\Delta F_I}{F_I} \right)^2 + \frac{\left( \frac{\Delta C_U}{C_D} + \frac{\Delta C_D}{C_U} \right)^2}{C_D - C_U} \right] + 2 \left[ \frac{\sum_{i=1}^{N} (F_I^i - F_1)^2}{(N - 1)F_I^2} + \frac{\sum_{i=1}^{N} (C_D^i - C_U^i - C_D + C_U)^2}{(N - 1)(C_D - C_U)^2} \right]}
\]  

(Equation 8)

- \( F_U \) = Upstream mass flow rate
- \( F_I \) = Injection concentration of gas tracer
- \( C_D \) = Downstream concentration of gas tracer
- \( C_U \) = Upstream concentration of gas tracer
- \( N \) = Sample number
The experiment was successful in showing that tracers can be utilised in certain situations to measure gas directly. However, in this study, only one type of tracer for gas was tested and only under a specific experimental set-up. Variances, such as detectors and sampling processes, were not discussed.

5.7 TracerCo – Field Test [26]

TracerCo has produced a number of case studies, showing applications of their services for both tracer dilution and tracer transit time. The case study summarised here is an example of TracerCo utilising the transit time methodology in an absorption tower to diagnose issues.

Under normal operation, spent liquor from an absorption tower passes through the bed of a regeneration tower and is removed using a draw tray, then goes through a heater. The heated liquor is then returned to the lower half of the tower, finally exiting at the tower bottom. However, a low temperature of the exit stream suggested that some flow might be bypassing the heater circuit.

In order to check this out, flow rate of the heated liquor and also that of the regenerated liquor were checked by pulse velocity measurements using the equipment layout shown in Figure 13.

![Figure 13 – Schematic of Absorption Tower](image)

Conclusion of the tests led to two main findings. The first was that no tracer pulse was detected by either of the detectors fitted on the loop with the heater element. This confirmed that there was no flow occurring through the heater and thus there was an issue with the draw tray. The second was that the measured velocity of the regenerated liquor via the tracer detectors fitted on the exit line of the absorption towers was much higher than expected, around four times greater than that was indicated by an orifice plate installed on the inlet to the tower, showing an error in the measurement of the inlet rate of the overall process.
This case study shows the versatility of tracers for the measurement of flow, even in a complex setup as shown here. However, as discussed previously, the use of transit time for accurate flow measurement may have higher uncertainties in comparison to the dilution technique.

5.8 Flow Measurement in Hydroelectric Stations Using Tracer Dilution Method – Case Studies [32]

Flow measurement remains a big challenge for field efficiency testing of turbines, especially in plants where provisions for flow measurement have not been made or the meters have become unusable.

The arrangement discussed for the flow measurement is shown in Figure 14 and Figure 15, involving the use of fluorescent dyes. Rhodamine WT was used as the dye as it is water soluble, harmless, highly detectable, inexpensive and reasonably stable.

![Diagram of tracer dilution technique](image)

**Figure 14 – Test Setup of Tracer Dilution Technique [32]**

Flow measurement in a pipeline with a diameter of 3.05 m and a length of 17.88 m was performed using the tracer dilution method.
The fluorometer was calibrated at 30 ppb before the commencement of dye injection. This enabled the reading of the sample to be around 25 to 50 ppb.

After flushing the tube and injection pump with the injecting dye, the suction side tube of the injection pump was slowly put inside the initially weighted volume jar with dye. The actual injection rate was measured during the test gravimetrically and varied between 0.7 to 1.06 cc/s, as shown in Table 9.

**Table 9 – Flowrate Measurements for Different Conditions** [32]

<table>
<thead>
<tr>
<th>% Loading</th>
<th>Injection rate cc/s</th>
<th>Mean concentration value, ppb $C_2 - C_0$</th>
<th>Discharge m³/s</th>
</tr>
</thead>
<tbody>
<tr>
<td>106.4</td>
<td>1.066</td>
<td>26.42</td>
<td>40.34</td>
</tr>
<tr>
<td>101.4</td>
<td>0.977</td>
<td>27.28</td>
<td>35.9</td>
</tr>
<tr>
<td>79.6</td>
<td>0.979</td>
<td>34.48</td>
<td>28.13</td>
</tr>
<tr>
<td>71.5</td>
<td>1.059</td>
<td>36.64</td>
<td>28.91</td>
</tr>
<tr>
<td>49.8</td>
<td>1.067</td>
<td>51.68</td>
<td>20.65</td>
</tr>
<tr>
<td>42</td>
<td>0.724</td>
<td>38.48</td>
<td>18.81</td>
</tr>
</tbody>
</table>

Dilution method is applicable only where the degree of mixing is within a tolerance limit. To ensure this, it is necessary to take different samples across the cross-section and determine the variation of tracer with respect to the pipe geometry. In this site, access to the tapping points was not possible and the only choice was to determine the concentration variation using the four tapping points of the draft tube. While injecting, readings were obtained from each tapping point by closing and opening the valves provided in the tapping points. An additional...
reading was obtained keeping all the values in the open condition. The results indicated a variation in the concentration at the draft tube as shown in Table 10.

### Table 10 – Concentration of Tracer at Each Tapping [32]

<table>
<thead>
<tr>
<th>Tapping No.</th>
<th>Concentration (ppb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.92</td>
</tr>
<tr>
<td>2</td>
<td>1.10</td>
</tr>
<tr>
<td>3</td>
<td>2.15</td>
</tr>
<tr>
<td>4</td>
<td>7.20</td>
</tr>
<tr>
<td>All the above four</td>
<td>3.20</td>
</tr>
</tbody>
</table>

Results from the different tapping points indicated that mixing was clearly not sufficient. The degree of mixing, using equation 9 given in ISO 9555-1, was determined to be only 55.57%. The target degree of mixing percentage as per the standard should be above 98%. [32].

\[
X = 100 \left[ 1 - \frac{\sum_{i=1}^{m} |C_{2i} - \overline{C}_2|}{2m\overline{C}_2} \right] \tag{9}
\]

- \(X\) = Degree of Mixing
- \(C_{2i}\) = Mean dye concentration (ppb) for tapping position \(i\)
- \(\overline{C}_2\) = Mean dye concentration for all tappings
- \(m\) = Number of tappings

A second study was also completed using the same methodology with a pipe diameter of 5.75 m and a length of 240 m. This test showed much better results due to an increased pipeline length for mixing. The degree of mixing was determined to be 98.46%, with an overall uncertainty of 3.09%.

Overall, the study confirm that dye tracer dilution technique can be used successfully for flow measurement in cases where other methods are not feasible.

The required mixing length as determined in standard guidelines for a single point injection demonstrate an error in mixing of 2%. This is very similar to the 3% error in mixing achieved in case 2.

The measurement of case 2 still remained within limits of the standard even though the concentration of injected dye in water was greater than the recommended range of up to 15%.

The research work shows the importance of making suitable provisions during the design and construction stage to ensure that accessibility is considered for access to tapping points and other required parts of the plant.
5.9 Particle Image Velocimetry Measurements of Stratified Gas-liquid Flow in Horizontal and Inclined Pipes [33]

Two phase gas and liquid flows using Particle Image Velocimetry were studied to determine the differences in velocity profiles in various horizontal pipes inclined from 5° upward to 5° downward. Figure 16 shows a schematic of the test set-up used in the research.

![Figure 16 – Experimental Test Schematic][33]

The experiments were performed in a 15 m long pipe with a diameter of 56 mm at ambient temperature and pressure. The fluids utilised during the testing are summarised in Table 11.

### Table 11 – Summary of Test Fluids [33]

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Gas</th>
<th>Oil</th>
<th>Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density at 15°C</td>
<td>1.22 kg/m³</td>
<td>793 kg/m³</td>
<td>999 kg/m³</td>
</tr>
<tr>
<td>Viscosity at 25°C</td>
<td>0.018 mPa·s</td>
<td>1.3 mPa·s</td>
<td>0.89 mPa·s</td>
</tr>
<tr>
<td>Surface tension at 25°C</td>
<td>25.9 mN/m</td>
<td>72.0 mN/m</td>
<td></td>
</tr>
</tbody>
</table>

Measurements were made at mixture velocity, 5 m/s for different inlet liquid fractions. The cross-sectional distribution of phase fractions was measured using a traversable single-beam gamma densitometer.

Particle Image Velocimetry was utilised to determine instantaneous velocity measurements of the phases, and thus mean velocities and Reynolds stresses can be determined. The PIV set-up used is shown in Figure 17.
The measurements covered two-phases, air/water and air/oil flow regimes with liquid fractions ranging from 0.1% to 1.0%, and five pipe inclinations from -5° to +5°. The measured velocity and turbulence profiles showed a strong dependency with pipe inclination. The results demonstrated that the PIV technique can be successfully utilised for measurement of two-phase flows in inclined pipes.

5.10 Advancements in Tracer Flow Testing; Development of Real-Time Technology for Flow and Enthalpy Measurements [34]

The measurement of enthalpy is important for geothermal applications as it is commonly used as a metric for determining changes in reservoir conditions. Several techniques have been previously used for online measurement of enthalpy in the geothermal industry. However, the most common methods are either conventional flow metering of each phase or by use of tracer dilution.

For the tracer technique, the mass flow rate of the target phase can be determined using equation 10, with the total enthalpy of the system calculated then using equation 11.

\[
Q_{L\text{ or } V} = \frac{Q_T}{(C_T - C_B)} \tag{10}
\]

\[
H_T = \frac{(Q_V \times H_V) + (Q_L \times H_L)}{(Q_V + Q_L)} \tag{11}
\]

- \(Q_L\) = Mass flow rate of liquid phase
- \(Q_V\) = Mass flow rate of vapour phase
- \(Q_T\) = Mass flow rate of tracer
- \(C_T\) = Concentration of tracer by weight
- \(C_B\) = Background concentration of tracer
- \(H_V\) = Enthalpy of vapour phase
- \(H_L\) = Enthalpy of liquid phase
- \(H_T\) = Total enthalpy of two-phase system

For two phase flow and enthalpy measurements, Tracer Flow Testing (TFT) has become a standard tool in the geothermal industry for reservoir and power plant monitoring. An online version of this, Continuous Tracer Flow Testing (CTFT) has recently been made possible as
a result of new tracer developments and improvements in an online method for the analysis of gas phase tracers.

Currently, the largest challenge for online tracer dilution techniques to measure the mass flow rate of liquid phases has been finding the right tracers and equipment that possess the sensitivity and speed required for continuous measurement. Table 12 displays some common tracers which have been trialled in the field previously.

Table 12 – Tracers Evaluated for TFT and CTFT Application

<table>
<thead>
<tr>
<th>Liquid Phase</th>
<th>Vapour Phase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluoride (as KF)</td>
<td>Propane</td>
</tr>
<tr>
<td>Bromide (as NaBr)</td>
<td>Sulfur hexafluoride (SF₆)</td>
</tr>
<tr>
<td>Fluorescein dye</td>
<td>Freon-12</td>
</tr>
<tr>
<td>Sodium Benzoate</td>
<td>Helium</td>
</tr>
<tr>
<td>Rhodamine WT dye</td>
<td>Isopropanol</td>
</tr>
<tr>
<td>1,5-napthalene disulfonate</td>
<td></td>
</tr>
<tr>
<td>2,7-napthalene disulfonate</td>
<td></td>
</tr>
<tr>
<td>Proprietary TT</td>
<td></td>
</tr>
</tbody>
</table>

Recent developments of a fluorescent tracer denoted TT, derived from polyaromatic sulfonates, allow it to be measured by a continuous brine monitoring system using direct fluorescence. This made online continuous enthalpy measurements possible.

Figure 18 displays a period of unstable flows monitored during testing and shows the tracer measurements fluctuating between the span of the flow range. The figure also clearly portrays the response time of the tracer technique.
In unstable flows, the use of the online tracer measurements shows a much higher resolution in comparison to standard sampling, as shown in Figure 19. This higher resolution allows for having a much clearer picture of what is actually occurring, as standard sampling approach produces much less details.

For the measurement of the steam phase, online determination of sulfur hexafluoride (SF₆) was carried out using a continuous steam monitor. During the test, the continuous steam monitor was able to provide tracer concentration in the steam phase in 60 second intervals.
In cases where well flow is relatively stable, data obtained using online continuous monitoring compares well with data from an offline tracer method. A comparison of average steam flow, brine flow, and total fluid enthalpy for the test is shown in Table 13.

### Table 13 – Comparison of TFT and C-TFT Results

<table>
<thead>
<tr>
<th>Flow Test Method</th>
<th>Average Steam Flow (KPH)</th>
<th>Average Brine Flow (KPH)</th>
<th>Average Total Fluid Enthalpy (btu/lb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TFT</td>
<td>166.9</td>
<td>518.2</td>
<td>558.5</td>
</tr>
<tr>
<td>C-TFT</td>
<td>169.8</td>
<td>520.7</td>
<td>560.4</td>
</tr>
<tr>
<td>%RSD</td>
<td>1.20%</td>
<td>0.35%</td>
<td>0.24%</td>
</tr>
</tbody>
</table>

The data from the gas tracer for steam and the liquid tracer for brine can be simply combined to determine the real time total enthalpy of the system.

![2-Phase Flow Rates and Fluid Enthalpy for Well-2](image)

**Figure 20 – Total Enthalpy Measurement from CTFT and TFT** [34]

More experimental data are shown in Figure 20 where flow rates and total fluids enthalpy obtained using the respective offline (represented by the dots) and online tracer methods (represented by the solid lines) are presented. It is clear that the online tracer technique has a much higher resolution in comparison to standard sampling tracer method.

Online method has clear advantages over the standard offline technique, however further improvements are still required, such as the detection limits for tracers in both the gas and liquid phases.

### 5.11 Tracer Dilution Measurements for Two-Phase Geothermal Production: Comparative Testing and Operating Experience [35]

A tracer dilution method was trialled in several geothermal projects in two locations; Roosevelt Hot Springs and Salton Sea. The projects investigated the use of tracer dilution in two-phase
geothermal applications in comparison to using a conventional single-phase orifice plate, measuring each stream individually.

The first project was carried out in 1992 at Roosevelt covering three wells. Two tracers, propane and potassium fluoride, were utilised during the trial. Table 14 shows the individual flow rate results obtained from the tracer dilution method and conventional orifice plate measurements. For the tracer dilution method, samples were collected downstream of a test separator.

Table 14 – Tracer vs. Orifice Measurements Downstream

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Steam Flowrate (kg/s)</th>
<th>Liquid Flowrate (kg/s)</th>
<th>Total Enthalpy (kJ/kg)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Orifice</td>
<td>Tracer</td>
<td>Δ%</td>
</tr>
<tr>
<td>R – 1</td>
<td>20.2</td>
<td>20.8</td>
<td>3.08</td>
</tr>
<tr>
<td>R – 2</td>
<td>18.1</td>
<td>17.8</td>
<td>-2.11</td>
</tr>
<tr>
<td>R – 3</td>
<td>11.8</td>
<td>11.6</td>
<td>-1.93</td>
</tr>
</tbody>
</table>

Table 15 summarises similar results, however with samples being taken upstream of the production separator. It should be noted that steam samples could not be captured for wells, R-1 and R-2 due to lack of sufficient sample points.
Table 15 – Tracer vs. Orifice Measurements Upstream

| Well Name | Steam Flowrate (kg/s) |  |  
|-----------|-----------------------|---|---|
|           | Orifice | Tracer | ∆% |
| R – 1     | 20.2    | -      | -  |
| R – 2     | 18.1    | -      | -  |
| R – 3     | 11.8    | 13.2   | 11 |

| Well Name | Liquid Flowrate (kg/s) |  |  
|-----------|-----------------------|---|---|
|           | Orifice | Tracer | ∆% |
| R – 1     | 103     | 105    | 2.17 |
| R – 2     | 94.3    | 97.6   | 3.41 |
| R – 3     | 61.5    | 149    | 83  |

Due to a lack of sufficient mixing time, an 83% deviation was noted for the liquid flow rate on well R-3. Only 7 m between injection and sample point was available, compared to up to 150 m for R-1 and R-2, which clearly shows the importance of having a sufficient mixing time to achieve reliable results for the measurements of liquid phase using the tracer dilution technique. The steam phase however, had a much lower deviation of 11%, which is thought to be due to the efficiency of mixing and dispersion for vapour phases. The degree of mixing within the liquid phase over a short pipe run may be limited by the large mass of water and with a slug flow nature.

The second project was carried out in the Salton Sea geothermal field in 1993. Propane and sodium bromide tracers were injected immediately downstream of the wellhead with the distance between the injection point and sampling points fixed at approximately 150 m.

Table 16 summarises the comparative test results for steam and brine mass flowrates and total enthalpy. The enthalpy calculation involves a correction for the salt content of the brine, which at 20% by weight causes a significant deviation from the enthalpy of pure water at the same temperature and pressure.
Table 16 – Tracer vs. Orifice Measurements Upstream

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Production Separator Samples</th>
<th></th>
<th></th>
<th>Δ%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Orifice</td>
<td>Tracer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Steam, kg/s</td>
<td>21.5</td>
<td>20.7</td>
<td></td>
<td>-3.86</td>
</tr>
<tr>
<td>Brine, kg/s</td>
<td>147</td>
<td>152</td>
<td></td>
<td>4.61</td>
</tr>
<tr>
<td>Enthalpy, kJ/kg</td>
<td>1019</td>
<td>1003</td>
<td></td>
<td>-1.60</td>
</tr>
</tbody>
</table>

A statistical error analysis for the tracer dilution technique was performed based on the known limits of error in the tracer injection rate, the analytical error in measuring the concentration of tracer in samples, and the estimated errors attributed to tracer mixing and sample collection.

The tracer injection rates were determined by instruments that were regularly calibrated against primary standards traceable to the National Institute of Standards and Technology (NIST). The tracers were analysed using the same standards and procedures as the geothermal fluid samples. The calculated uncertainty analysis results are summarised in Table 17.

Table 17 – Tracer Dilution Method Error Analysis

<table>
<thead>
<tr>
<th>Steam Phase</th>
<th>Cumulative Error</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Tracer Conc.</td>
<td>Calibration</td>
</tr>
<tr>
<td>±2.0%</td>
<td>±1.5%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Liquid Phase</th>
<th>Cumulative Error</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquid Tracer Conc.</td>
<td>Calibration</td>
</tr>
<tr>
<td>±1.0%</td>
<td>±0.5%</td>
</tr>
</tbody>
</table>

Cumulative Error in Total Enthalpy ±3.4%
Based on errors estimated, the tracer dilution method has been proven to be a potential alternative measurement method for mass flowrate of gas, and liquid and also total enthalpy of two phase flows.

5.12 Multiphase Flow Measurement Using Tracer Technology at Dulang Oil Field, Malaysia [36]

A tracer dilution technique was trialled in the Dulang field in Malaysia to measure wellhead multiphase flow rates in over 65 wells. The trial covered a wide range of conditions, which have been summarised in Table 18.

**Table 18 – Summary of Test Conditions**

<table>
<thead>
<tr>
<th>Property</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas flow rate (sm³/d)</td>
<td>0</td>
<td>165,900</td>
</tr>
<tr>
<td>Oil flow rate (m³/d)</td>
<td>20</td>
<td>319</td>
</tr>
<tr>
<td>Water flow rate (m³/d)</td>
<td>0</td>
<td>489</td>
</tr>
<tr>
<td>Water cut (%)</td>
<td>0</td>
<td>93</td>
</tr>
</tbody>
</table>

Other than the tracer technique, two traditional methods were also employed, a test separator and multiphase meter, with the data being utilised to cross-reference the results of the tracer technique. Figure 21 shows a schematic of the test set-up used for the tracer dilution method.

![Tracer Dilution Test Setup](image)

**Figure 21 – Tracer Dilution Test Setup** [36]

Using the tracer dilution method, as discussed previously, the liquid phase flow rate can be determined using equation 12.
\[ Q = \frac{q_t}{\beta} \]  \hspace{1cm} (12)

\( Q \) = Target fluid flow rate  
\( q_t \) = Tracer injection rate  
\( \beta \) = Tracer dilution factor

The tracer dilution factor is determined using the tracer concentration measured in target sample compared to the background reference sample, and is calculated using equation 13:

\[ \beta = \frac{\beta_o (F_S - F_B)}{(F_R - F_B)} \]  \hspace{1cm} (13)

\( F_S \) = Analysis signal from sample  
\( F_B \) = Background signal  
\( F_R \) = Reference signal

In comparison to calculating the liquid flow rate, the gas flow rate is considered more challenging to measure due to the fact that gas tracers may partition into the liquid phases. Partitioning is where part of the gas tracer becomes dissolved in the liquid phase, which can cause significant errors in the gas flow measurement. This effect does not occur for the liquid tracers as they generally do not partition into the gas phase.

It was stated that tracer partitioning into the gas phase was negligible during these trials as the pressure was less than 20 bar; partitioning becomes more severe at higher temperatures and pressures. Assuming partitioning does not occur, equation 14 can be utilised to determine gas flow rate:

\[ Q_g = \frac{q_i}{(C - B_g)} \]  \hspace{1cm} (14)

\( Q_g \) = Gas flow rate  
\( q_i \) = Gas tracer injection rate  
\( C \) = Gas tracer mole fraction  
\( B_g \) = Background gas tracer mole fraction

Sources of uncertainties in the measured flow rate using the tracer method can be divided into four parts; measured injection rate, mixing efficiency, tracer partitioning and tracer concentration analysis.

The measured injection rate uncertainty is typically less than 1% when a Coriolis meter or similar is used for measuring the liquid tracer injection rate. However, it can be up to around 3% to 4% for the gas tracer injection rate.

The uncertainty associated with insufficient mixing of the tracer is challenging to estimate. Tracer dilution techniques rely on complete mixing of the selected tracers with their target phases at the sampling point. Previously 150 diameters of straight pipe have been mentioned to be sufficient.
For gas tracers the partial loss of tracer into the liquid phases means that the gas flow rates obtained will be on the high side. In Figure 22, this systematic error is plotted against the liquid molar fraction for two different pressures. At pressures larger than approximately 100 bar, the partitioning will start to be noticeable at low liquid mole fractions, with the amount of gas tracer lost into the liquid being dependent on the liquid fraction present in the flow.

\[ E = 100 \times \left( \frac{x}{1 + (1 - x)(K - 1)} \right) \]  

(15)

\( E \) = Partition Error (%)  
\( x \) = Liquid mole fraction

Figure 22 – Partitioning Effect for Different Pressures Using Helium [36]

Figure 23 – Partitioning Effect for Different Pressures Using Argon [36]
\( K \) = Thermodynamic equilibrium constant

Based on the flow calculation shown in equation 12 previously, the individual uncertainties of each factor can be determined using the following methodology [36].

Uncertainty in injection rate:

\[
\frac{\delta Q}{\delta q_i} \left( \frac{\Delta q_i}{Q} \right) = \frac{\Delta q_i}{q_i}
\] (16)

Uncertainty in dilution factor:

\[
\frac{\delta Q}{\delta \beta_0} \left( \frac{\Delta \beta_0}{Q} \right) = -\frac{\Delta \beta_0}{\beta_0}
\] (17)

Uncertainty for signals:

\[
\frac{\delta Q}{\delta F_R} \left( \frac{\Delta F_R}{Q} \right) = \frac{\Delta F_R}{(F_R - F_B)}
\] (18)

\[
\frac{\delta Q}{\delta F_S} \left( \frac{\Delta F_S}{Q} \right) = \frac{\Delta F_S}{(F_S - F_B)}
\] (19)

\[
\frac{\delta Q}{\delta F_B} \left( \frac{\Delta F_B}{Q} \right) = \frac{\Delta F_B}{(F_S - F_B) - (F_R - F_B)}
\] (20)

It was noted that uncertainties are typically in the range of 3% to 5%, however no confidence levels were given.

The tracer results from the trials are shown in Tables 19 and 20. Overall, for site Dulang A, 12 trials were performed on 12 wells and on site Dulang B, 20 trials were performed on 17 wells.
Table 19 – MultiTrace Tracer Test Results for Dulang A

<table>
<thead>
<tr>
<th>No.</th>
<th>Well</th>
<th>MultiTrace</th>
<th>Gas Trace</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Oil Rate (Sm$^3$/d)</td>
<td>Water Rate (Sm$^3$/d)</td>
</tr>
<tr>
<td>1</td>
<td>15L</td>
<td>91.46</td>
<td>67.96</td>
</tr>
<tr>
<td>2</td>
<td>19</td>
<td>75.82</td>
<td>65.42</td>
</tr>
<tr>
<td>3</td>
<td>8</td>
<td>64.15</td>
<td>86.65</td>
</tr>
<tr>
<td>4</td>
<td>7</td>
<td>93.69</td>
<td>Trace</td>
</tr>
<tr>
<td>5</td>
<td>26S</td>
<td>104.74</td>
<td>82.52</td>
</tr>
<tr>
<td>6</td>
<td>27S</td>
<td>86.64</td>
<td>-</td>
</tr>
<tr>
<td>7</td>
<td>16L</td>
<td>94.40</td>
<td>-</td>
</tr>
<tr>
<td>8</td>
<td>2S</td>
<td>176.48</td>
<td>191.61</td>
</tr>
<tr>
<td>9</td>
<td>6</td>
<td>49.10</td>
<td>404.97</td>
</tr>
<tr>
<td>10</td>
<td>10L</td>
<td>117.15</td>
<td>-</td>
</tr>
<tr>
<td>11</td>
<td>1</td>
<td>63.59</td>
<td>210.08</td>
</tr>
<tr>
<td>12</td>
<td>10S</td>
<td>365.76</td>
<td>-</td>
</tr>
</tbody>
</table>
Table 20 – MultiTrace Tracer Test Results for Dulang B

<table>
<thead>
<tr>
<th>No.</th>
<th>Well</th>
<th>MultiTrace</th>
<th>Gas Trace</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Oil Rate (Sm$^3$/d)</td>
<td>Water Rate (Sm$^3$/d)</td>
</tr>
<tr>
<td>1</td>
<td>25S</td>
<td>31.89</td>
<td>106.58</td>
</tr>
<tr>
<td>2</td>
<td>17S</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>3</td>
<td>25S</td>
<td>40.35</td>
<td>167.27</td>
</tr>
<tr>
<td>4</td>
<td>15S</td>
<td>318.94</td>
<td>-</td>
</tr>
<tr>
<td>5</td>
<td>5S</td>
<td>294.00</td>
<td>96.61</td>
</tr>
<tr>
<td>6</td>
<td>12</td>
<td>149.59</td>
<td>141.45</td>
</tr>
<tr>
<td>7</td>
<td>8</td>
<td>37.03</td>
<td>132.86</td>
</tr>
<tr>
<td>8</td>
<td>7S</td>
<td>25.63</td>
<td>3.76</td>
</tr>
<tr>
<td>9</td>
<td>7L</td>
<td>121.76</td>
<td>6.35</td>
</tr>
<tr>
<td>10</td>
<td>1L</td>
<td>264.64</td>
<td>-</td>
</tr>
<tr>
<td>11</td>
<td>21L</td>
<td>112.22</td>
<td>83.84</td>
</tr>
<tr>
<td>12</td>
<td>22L</td>
<td>55.31</td>
<td>10.21</td>
</tr>
<tr>
<td>13</td>
<td>22S</td>
<td>123.03</td>
<td>Trace</td>
</tr>
<tr>
<td>14</td>
<td>29L</td>
<td>201.63</td>
<td>-</td>
</tr>
<tr>
<td>15</td>
<td>24</td>
<td>114.60</td>
<td>72.40</td>
</tr>
<tr>
<td>16</td>
<td>2S</td>
<td>31.21</td>
<td>94.10</td>
</tr>
<tr>
<td>17</td>
<td>25S</td>
<td>19.53</td>
<td>161.09</td>
</tr>
<tr>
<td>18</td>
<td>27S</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>19</td>
<td>15L</td>
<td>31.11</td>
<td>178.22</td>
</tr>
<tr>
<td>20</td>
<td>25S</td>
<td>23.06</td>
<td>174.96</td>
</tr>
</tbody>
</table>

Several issues occurred using the test separator during the trial. Only total liquid flow rate was able to be measured as separation between the oil and water phase was insufficient for individual phase measurement. It was also not possible to achieve a reliable measurement for the gas flow rate from the test separator.

Due to the issues with the test separator, a comparison of gas flow rate could only be achieved between the tracer technique and multiphase meter. Gas flow rate results are shown in Figure 24.
Figure 24 – Tracer Technique vs Multiphase Meter for Gas Flow Rate [36]

Figure 24 shows that results from the tracer technique and multiphase meter compare within about 10%, however outliers were also noticed at high GVF conditions. This was likely due to mis-measurement of the multiphase flow meter which can have issues in these conditions.

Figure 25 shows a comparison of the tracer technique against the multiphase meter and test separator for the total liquid flow rate.

Figure 25 – Tracer Technique vs. Multiphase Meter and Test Separator [36]
Figure 26 displays results from the tracer technique against the multiphase meter for the measurement of oil phase only. The test separator was not included as data on the individual liquid flow rates were not available.

Figure 26 – Tracer Technique vs. Multiphase Meter for Oil Flow Rate [36]

The tracer technique used showed a good comparison against test separator and multiphase meter data when trailed in a large number of wells. Overall, uncertainties of up to 5% were achieved for liquid measurement, and up to 10% for gas flow rate.
6 PATENT REVIEW

6.1 Exxon Research Engineering Co (1966) - Hydrocarbon tracers for use in the conversion of hydrocarbons [37]

A new type of radioactive tracers, metallic porphyrin chelates, are invented and evaluated for measurement of hydrocarbons. The tracers may be synthesized from porphyrin-type compounds and radioactive isotopes of metals to form a radioactive metal porphyrin. They are oil soluble and their composition may be varied to produce compounds having boiling points up to 800°C.

In addition, the chelates invented are relatively stable and many are known to be volatile under vacuum distillation conditions, and hence, considered to be valuable radioactive hydrocarbon tracers in petroleum processes.

6.2 Imperial Chemical Industries Plc (1986) - Flow rate measurement [38]

A method for determining volumetric flowrates of multiphase fluids is described. A known amount of radioisotope tracer is injected into at least one of the phases and the concentration of the tracer in the flow is determined at a downstream sampling station, thereby enabling the flow rate of the multiphase flow to be determined. The tracer used should be soluble in only one phase of the fluid flow with the provision that where multiple tracers are used, each phase only contains a single soluble tracer.


A method of determining the flow velocity of fluid flowing within the borehole of a well with a non-radioactive tracer is described. A population of neutrons is generated in a stream of fluid to a detector capable of detecting neutron capture. A substance of large thermal neutron capture cross section is injected into a stream of fluid at a known distance upstream from a detector. Measurement of the time that the tracer travels over a known distance allows for calculation of the velocity of target fluid.

6.4 Shell Oil Company (1992) – Method utilizing spot tracer injection and production induced transport for measurement of residual oil saturation [40]

A method is described for providing sharp breakthrough of tracers in a two-well tracer test by injecting a relatively small volume of tracer at a high rate into a temporary injection well, and utilizing the flow induced by producing wells to transport the tracers across the formation to a producing well. Measurement of residual oil saturation and sweep can be obtained by this method.

6.5 Schlumberger Technology Corporation (1996) - Method of measuring flow velocities using tracer techniques [41]

A method of measuring flow velocities in a flow by injecting into a non-radioactive tracer which has a neutron capture cross section higher than that of the flowing fluids is described. This is achieved by measuring the neutron capture cross section in the target fluid downstream of the
injection point to detect the path of the tracer. The time taken to reach the downstream location is then used to determine flow velocity. The neutron capture cross section can be measured by irradiating with neutrons from a pulsed neutron generator and measuring capture gamma rays with a scintillation detector.

6.6 Schlumberger Technology Corporation (1998) - Gadolinium compounds for use as oil-soluble tracers [42]

This patent describes a tracer solution suitable for use in measuring flow velocities in boreholes, which includes:

1. A gadolinium salt of a carboxylic acid
2. A free branched-chain carboxylic acid such as an excess of the acid used to form the gadolinium salt
3. A non-polar solvent such as hexane or heptane.

6.7 Bielski; Roman, Carter; John (1999) - Apparatus and method for measuring multiphase flow [43]

Apparatus and a method for determining the flow rate of one or more phases of a fluid is described. By measuring the activity, as a function of time, of specific radioactive isotopes affected by a specific phase of the flowing fluid stream, the target flow rate can be determined. Radioactive isotope material is deposited upon one or more inserts, and each deposition of the isotope material is coated with a corresponding phase coating. Each phase isotope and corresponding phase coating is soluble in only one phase of the multiphase flow. The inserts are wet into the target fluid, and the time required for each flow phase to wash the corresponding phase coating from the insert is measured. Phase flow parameters of interest are then determined from the measured phase isotope release times.

6.8 Statoil ASA (2008) - Tracer measurement in multiphase pipelines [44]

This patent covers measurement of total phase volumes in multiphase flow in pipelines. The method determines the fractions of hydrocarbons, water and solid phases. Tracers are injected into the pipeline, as close to the inlet as possible and the tracer concentrations are measured as a function of time at the injection and also at one or more locations downstream of the injection point.

The mean residence times are measured for transport of the injected tracers from the point of injection to downstream locations. The liquid phase volumes are calculated based on the amount of injected tracers and the measured tracer concentrations in each phase and the mean residence time.

6.9 Lux Innovate (2011) - Method to assess multiphase fluid compositions [45]

The method describes an approach of applying a property modification to a sample of multiphase fluids. The process involves applying additives which disperse as a result of this modification and emit signals for analysis when irradiated. This allows the phase properties to be determined and treatment chemicals to be detected.
6.10 China National Petroleum Corporation, Daqing Oilfield Co., Ltd (2013) - Non-radioactivity tracing flow well logging method and process based on pulse neutron technology [46]

This method is based on the pulse neutron technology and includes using a solution of a non-radioactive substance, such as a gadolinium compound or a boron compound. Utilising a high heat neutron capture cross section as a tracing agent, the neutron lifetime manner can be used to measure the macroscopic capture cross section of fluid in a well.

The high-strength pulse neutrons emitted by a pulse neutron generator to bombard the tracing agent, capturing heat neutrons by the tracing agent, using different well logging processes to record heat neutron time spectrums or the heat neutron counting rate of a fixed spacing detector. Using this, calculating the flow speed of the fluid in the well and the use conditions of a thin difference layer can be done by analysing well logging data.

The non-radioactivity tracing flow well logging method and process based on the pulse neutron technology has following advantages:

- Free of radiation risks which meets the environment-friendly requirement
- Low in measuring lower limit
- Effectively solves the problem that a current layering injection well is low in flow and large in monitoring error
- Wide site adaptability

6.11 University of Utah Research Foundation (2015) - Downhole deployable tools for measuring tracer concentrations [47]

This method describes an apparatus which comprises of a support cable configured to allow the apparatus to be lowered into and raised from a wellbore. A housing is attached to the support cable. The housing includes a detector window on the exterior of the housing. A detector system within the housing includes a detector that measures tracer concentrations. The detector is operably connected to the detector window to direct energy or particles from the detector window to the detector.

6.12 Expro (2015) - Minimally intrusive monitoring of a multiphase process flow using a tracer and a spatially arranged array of at least two sensors on a flow pipe [48]

A new method for measurement of multiphase flows is described with following claims:

- Sensing the fluid flow with a meter attached to an exterior of the pipe. The flowmeter includes a spatial array of at least two sensors fixed at different axial positions along the pipe, which produce flow velocity signals indicative of a velocity of the fluid flowing within the pipe
- Selectively injecting at least one tracer into the fluid flowing inside the pipe, at a known injection flow rate and concentration
- Sensing a sample of the fluid flow for the tracer, and producing tracer concentration signals indicative of the concentration of the tracer in the fluid flow; and
• Determining one or more of a gas component flow rate, an oil component flow rate, and a water component flow rate, using one or more of the flow pressure value, the flow temperature value, the flow velocity signals, and the tracer concentration signals.

6.13 Saudi Arabian Oil Company, Cornell University (2016) - Carbon-based fluorescent tracers as oil reservoir nano-agents [49]

A new carbon-based fluorescent nano-agent tracer for analysis of oil reservoirs properties is described. The carbon-based fluorescent nano-agents may be used for the analysis of the porosity of a formation. The nano-agents are suitable for injection into a petroleum reservoir and may be recovered from the reservoir for the determination of hydrocarbon flow rates and retention times.
7 VERIFICATION OF MPFMS

It is clear that tracer technology can potentially provide a valuable tool for verifying flowmeter performance in situ. However, it is evident from discussion in sections 4 and 5 that tracer technologies typically show good performance for single phase flows but challenging for multiphase flow applications. This report aims to assess the performance of tracer technologies for their potential uses in verifying commercial MPFMs deployed in the oil and gas industry, in particular those that are installed in a challenging environment, e.g. subsea. These applications pose significant challenges for verification as they inhibit the performance of tracer technologies both from a measurement and practicality point of view.

For oil and gas production, high pressures and temperatures of well fluids are commonly found in conjunction with a wide range of contaminants that can have adverse effects on flow assurance. Any tracer used will have to be compatible with the well fluids as well as those contaminants and be stable at operating conditions. Stability in this sense refers to its phase and its solubility in each of the flow components.

Multiphase flow by its nature involves multiple phases or components in the flow. The current method utilising tracers in multiphase flows is to have separate tracers soluble in one component only and take a measurement analogous to single phase flow. This process relies on the assumption that the tracer is truly insoluble in other components. At higher pressures and temperatures found in multiphase flowlines, this assumption may not always hold, and corrections may be needed.

Section 4 shows numerous examples of tracers being used in industry with measurement uncertainties comparable to commercial MPFMs. In theory, they should be able to offer a viable method for verification of MPFMs as long as practical issues can be overcome and measurements are managed carefully. For any tracer method to be successful, it would likely have to be based on a continuous measurement system that avoids, or more likely limits, the use of taking samples. This would be especially important for subsea applications. The tracer itself would have to be low cost for a continuous system and a full appreciation of its physical properties over the range of operating conditions would be required. In particular, its interaction with all components of the multiphase flow must be understood.

In addition to these general requirements, it has also been shown that specific practicalities are important to reduce the uncertainty of tracer-based measurement methods:

- Partitioning – the effect of increasing solubility of tracers in different immiscible components with an increasing pressure and temperature
- Mixing – the effect of tracers not being homogeneous across the pipe cross section, i.e. part of the fluid not being exposed to the tracer fully
- Installation – the effect of the application location, conditions and access to infrastructure. This applies more to subsea and other less accessible places
- Tracer Injection Measurement – The uncertainty in tracer injection volume. High-pressure low-volume injection systems have their own challenges for attaining low measurement uncertainties
- Tracer Volume – for continuous measurements, a large volume of tracer would be required over a time period. Storage, transport and infrastructure will need to be in
place to accommodate this. It also has implications for subsea conditions with tie-backs as there may be long associated flowlines

- Tracer Measurement – This could be online, offline through manual sampling or some other means.

Currently, there is no system that satisfactorily addresses every aspect and meets the requirements above. More work is required to fully quantify the performance of tracer-based techniques for MPFM verification applications. Ideally, the uncertainties associated with these tracer-based techniques under a diverse range of operating conditions can be better understood and quantified. This will provide the oil and gas industry with a more realistic expectation of what can be achieved in operations.
8 CONCLUSIONS

The objective of this research was to investigate the potential use of tracer techniques for measurement of multiphase flows as a verification tool in the Oil and Gas industry. The primary searches during this study were conducted using Google Scholar and the University of Coventry resource databases; however other resources, such as conference papers, were also included.

One of the main challenges found was that much of the research, test and field trial work undertaken to date focused on aspects other than the tracer technique itself. An example of this would be where tracer technologies were utilised to validate another novel method for measurement. Due to this, there are limited resources available which directly cover advancements in tracer techniques. Also, much of the work completed has not been recent, with the majority being carried out over 5 years ago. Several techniques have been used and investigated by various end users and service providers. But data published from these investigations are thought to be of limited value. However, some of the literature suggests that the technique may offer a means of verifying multiphase or virtual meters in situ with estimated method uncertainties not dissimilar to those currently employed for verifying MPFMs.

Patents identified during this literature review were found to be very broad, covering many aspects with knowledge already in the public domain. However, the patents do give an insight into which organisations have been actively developing tracer techniques for multiphase flow measurement. These organisations called for the potential of the techniques to be recognised in particular in an anticipation with advances in tracer chemistry and sensor technology. Some patents have shown that the chemistry has advanced such that a tracer can be added and only stay in a target component of the multiphase flow.

Most tracer techniques have been primarily operated in batch processes in which manual spot samples are required to be taken downstream of where the tracer is injected tracer for analysis. There are practical issues such as unsteady flows, remote and subsea environments which can significantly limit the effective use of these techniques. The development of a continuous tracer technique would be required for proper in-situ verification applications, and only a limited amount of research in this field has been carried out. Other than oil and gas, there have been developments and ongoing research in other industries e.g. geothermal, knowledge gained there may be transferrable.

Practical challenges also need to be considered when evaluating tracer techniques in closed loop laboratory research systems where continuous build-up of injected chemicals would need to be considered. The impact of this depends greatly on the total capacity of the facility; however, it will have an effect on the design of the experimental methodology.
9 RECOMMENDATIONS

Based on the findings from this study, it is recommended that a thorough cross-discipline scientific investigation to systematically assess the potential of the tracer dilution techniques to be conducted, given the emerging market interest and its current state of development. The investigation should focus on: tracer techniques; type of tracers; effect of flow regimes and uncertainty of measurement.

By undertaking such an investigation in a scientifically controlled environment, a clear comparison could be made between the tracer techniques and conventional reference flow measurements. The data collected would show the benefits and limitations of trace dilution techniques to give a better understanding on their applicability to MPFM verification applications. At present, the published work available, although indicating the potential of the technique, does not give a clear understanding of the performance for different tracer methodologies.

Potential avenues to consider:

- Flow loop testing
- Theoretical study of tracer diffusion and flow regime effect
- CFD analysis

Initially the aim should be to establish achievable phase flow rate measurement uncertainties, susceptibility to flow regime and rangeability. Subject to the outcome of this initial work, the concept of using tracer dilution techniques for MPFM verification is then developed to a Technology Readiness Level 2 (TRL 2) with practical issues of implementation under challenge environment investigated.
10 REFERENCES


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