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Subsea Multiphase Flow Measurement – A New Approach

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1 ABSTRACT

Multiphase flow measurement in extreme environments such as subsea or in-well is a difficult task for many reasons including reliability/survivability/longevity issues, accessibility to the equipment, and complexity of the varying flow field as a function of position and time. These challenges are substantial when compared to the relatively benign environments for surface flow measurement, but the benefits are also substantial with respect to production optimization and flow assurance.

In the last decade, the interest in subsea multiphase flow measurement has increased considerably for technological as well as economical reasons. From a technological perspective, the emergence of new optical and electronic sensors that can operate in harsh environments have fueled new thinking about ways for optimizing production and lowering overall operating costs. From an economical perspective, the higher cost of production is placing a premium on a better understanding of every well's performance.

A new approach in subsea multiphase flow measurement is introduced in this work. The approach combines two robust and field-proven technologies. One is based on the infrared water-cut measurement technology which is capable of measuring water and oil concentrations in multiphase flow with up to 99.5% gas volume fractions. The second technology is based on in-well fiber-optic flow measurement capable of resolving gas and total liquid flow through the measurements of flow velocity, fluid mixture speed of sound, and absolute pressure and temperature at meter location. The in-well flowmeter is non-intrusive, full-bore with no permanent pressure loss, and has high resilience to erosion and corrosion. A Red Eye® Subsea water-cut meter positioned at the subsea wellhead makes precise measurements of water cut in any multiphase stream, and dynamically sends this information to the optical flowmeter's computer at the offshore platform or floating production facility. The flow computer then utilizes this information along with the in-well measurements of velocity, speed of sound, pressure, and temperature. This hybrid system consisting of water-cut measurements at the subsea wellhead and flow measurements in the well represents a novel approach to subsea multiphase metering that may offer advantages to traditional systems for some applications. The solution is valid for all orientations from vertical to horizontal configurations. The current work is an introduction to how this new measurement approach works and how it is applied to different flow applications.

2 BACKGROUND

2.1 Red Eye® Subsea Water-Cut Meter

The first Red Eye® Water-Cut meter was introduced in 1998. It was a single wavelength near-infrared (NIR) device designed for high water cut measurement. It was essentially an oil-in-water meter with an operating principle based on oil absorption of the NIR beam. In 2005, the second generation (Red Eye® 2G meter) was introduced with dramatically expanded capability. The Red Eye® 2G meter was designed for full range measurement (0-100% water-cut) using four NIR wavelength bands including both oil and water absorbent bands. The meter body was completely redesigned converting to an insert probe style with enclosed electronics. The design changes included incorporation of state-of- the-art optoelectronics that gave the Red Eye® 2G meter detection capabilities far better than can be found on most laboratory spectrometers. The design changes improved accuracy across the board and expanded the operating envelope in terms of pressure, temperature, water-cut, free gas immunity, and sand immunity [1 – 2]. Over 1,500 meters have been installed worldwide since 2005.

In 2009, the Red Eye® MP meter was introduced for standalone water-cut measurement in a multiphase or wet-gas stream. The Red Eye® MP meter is based on the 2G platform and extends the excellent free gas immunity to any multiphase stream. While the Red Eye® 2G meter can handle roughly 20% gas volume fraction (GVF) without measurement error, the MP version can be used up to 99.5% GVF [3]. The Red Eye® MP meter was designed for standalone water-cut measurement at the wellhead and is also used in Weatherford's Alpha VSRD multiphase meter. In 2008, a joint industry project was formed by a number of major oil companies to validate the Red Eye® MP meter with an eye towards eventually applying this technology subsea.

Figure 1: Red Eye® MP and Subsea Water-Cut Meters

The development of the Subsea Red Eye® water-cut meter was primarily a marinization exercise. The measurement capabilities are essentially the same as found on the Red Eye® MP meter. The design changes are based on handling the subsea environment and process pressures up to 15,000 psi. Additionally, design changes were made to extend service-free operational lifetime to over 25 years and to support SIIS II and SIIS III communications. As of the date of this publication, production prototypes have been flow loop tested but there have been no subsea deployments. The first commercial units will be delivered in 2013.

2.2 In-Well Optical Flowmeter

The optical flow measurement technology was first introduced to the oilfield in deepwater Gulf of Mexico at a depth of 6.5 km in the year 2000 [4 – 5]. The flowmeter provided valuable pressure, temperature, and volumetric flow rates. Another field trial was conducted in June 2001 in Oman [6]. The objective of the field trial was to determine the capability of the meter to operate with heavy and viscous crude, as well as its operability in the presence of electric submersible and beam pumps. In addition to these initial field trials at these early stages, there was one installation in a gas condensate well offshore of Trinidad in the first half of 2002 [7 – 9]. This installation practically represented the first gas/liquid two-phase installation and the first application measuring a downhole flowing gas phase. In the first month of the installation, the free gas fraction downhole increased from 0 to above 60% levels, indicating gas coning. The early and rapidly changing free gas production coupled with the high deviation of the well resulted in a flow from an initial simple homogeneous flow regime to a complex heterogeneous one with significant slippage between the oil and gas phases. The flow eventually turned into a gas-rich flow and the production change was captured by the flowmeter with excellent agreements to the test separator. In one particular case, the flowmeter helped diagnosing a test separator failure due to a leakage, and as a result, the test separator was taken out of service and potential allocation errors were prevented. Five years after the installation, the operator reported a failed component in the top-side equipment. The failed component was replaced and the firmware was upgraded. This was sufficient to reestablish the communication between the top-side instrumentation and the downhole flowmeter. The comparisons of test separator and the flowmeter in late 2007 have shown that the gas flow rates were still within 3% of the test separator with excellent flowmeter signal quality [10]. This was a validation of the flowmeter from functionality, continuity, and accuracy perspectives.

Built on the field-proven two-phase flowmeter, a three-phase version of the in-well optical flowmeter was installed in a North Sea well in the first half of 2003. However, the well has not produced water phase yet, and the three-phase methodology could not be demonstrated in the field. In a subsequent effort in 2006, a joint industry project (JIP) was formed to evaluate the three-phase flowmeter performance using this methodology under controlled laboratory conditions. A multiphase flow loop in Porsgrunn/Norway was used for a 3-week test program which included an extensive test matrix with two different realistic pressures to replicate the downhole conditions. The three-phase measurement methodology requires differential pressure (ΔP) measurement between two pressure sensors separated vertically by about 100 m. Since this was not possible in laboratory, a non-ideal electronic ΔP system was developed. The test results were successful overall, and an operation envelope was developed. The three-phase measurement capability of the in-well flowmeter for near-vertical wells is currently being investigated for horizontal applications with some hardware modifications and subject of another JIP study.

One of the key developments started in late 2006 was the field-wide use of optical flowmeters in the North Sea where the optical sensing deployment was planned with an initial scope of 27 wells. Each well was equipped with two-phase optical flowmeters at depths where the pressure is above bubblepoint, and to date, the flowmeters have been providing excellent phase flow rate measurements of oil/water mixture [11]. Because these systems have demonstrated extremely reliable performance, the number of meters in this particular field has grown to 30. All of the two-phase flowmeters are supported by a single top-side instrumentation, and as new flowmeters are installed, they are added to the instrumentation interface. As a testimony to the successful field-wide installation and operation of optical flowmeters, the operator decided to implement a new field-wide installation program in the development of a new field with multizone wells. The wells will have 3 to 4 zones with an installation plan of one flowmeter per zone.

The optical flowmeter has become an important component of permanent downhole monitoring systems (PDMS) especially for applications where flow measurement is required and/or valuable. One such application was a 4-zone intelligent water-alternating-gas (WAG) injector installation in the North Sea in 2004 which was one of the milestones in using the flowmeter in the presence of inflow control valves (ICVs). This first experience with the ICVs provided an initial understanding of the behavior of optical flowmeter under high acoustics originated from the presence of ICVs [12]. When increasing the injection rates from moderate levels to high levels, the flowmeter signals were being affected adversely. The operator and the equipment manufacturer worked together to investigate the issue in a step-rate test. Improvements were made in the flowmeter data acquisition software which gave it a faster acquisition capability to handle the fast-changing flow conditions, and the flowmeters regained functionality. These improvements were made while the flowmeter was in operation. A similar experience was gained from the two-phase flowmeter installations in Middle East as a part of an intelligent well completion system in a tri-lateral maximum reservoir contact well in 2006. This particular system also included ICVs to optimize the production and three two-phase flowmeters were installed with ICVs. A series of production tests with various combinations of ICV settings (i.e., valve openings) were conducted. The flowmeters were functioning normally for most of the ICV settings with some exceptions: at lower ICV settings, the dramatic area change across ICV generated severe acoustic noise which dominated the flow signal [13 – 14]. One reason that contributed to this result was the fact that the flowmeters were in close proximity to ICVs. Recognizing the adverse effect of ICVs on the flowmeters, an R&D program was started to develop a new generation optical flowmeter system to overcome this issue. Starting in 2006, the flowmeter system was essentially redesigned to make it acoustic-tolerant. The development process was completed in 2010, resulting in new generation acoustic-tolerant flowmeter systems. A fair amount of development tests in laboratory, as well as performance testing under realistic conditions were part of this program [15]. Furthermore, following the successful laboratory tests, two more field tests were conducted at the same location in the Middle East with excellent results.

A more complete background of the in-well optical flowmeter, its development from initial prototype to latest state, its technology, its strong and weak points with specific field examples have been discussed in a recent work [16].

3 SUBSEA FLOWMETER INTRODUCTION – COMPONENTS

3.1 Red Eye® Subsea Water-Cut Meter Operating Principle

The Red Eye® subsea water-cut meter is the subsea version of the Red Eye® MP water-cut meter designed for accurate measurement of water detection, water-cut, and water-methanol ratio (or other typical hydrate inhibitor) in any multiphase stream. The wetted end consists of a flange mounted insertion style probe (Figure 2). The probe is made of high strength and corrosion resistant alloys (Incoloy 925 and Hastelloy C276) with permanently sealed sapphire optical windows. The meter is completely self-contained with the electronics canister attached above the flange. The meter requires low DC power (<8 watts) and supports a variety of digital outputs.

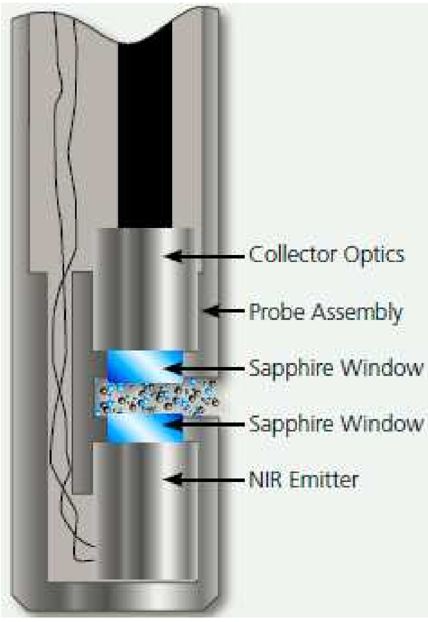

Figure 2 – Red Eye® Subsea water-cut meter probe.

The water-cut meter's key features include non-nuclear measurement approach, unit compactness, measurement robustness, low power usage, phase density independence, salinity independence, and slug frequency calculation mode as well as its capability of providing real-time instantaneous water-cut measurement or a liquid-weighted average over a user-specified time period. The meter is also capable of measuring relative concentrations of water and methanol or other typical hydrate inhibitors. The meter is available for any process line. The pressure rating of the Red Eye® Subsea water-cut meter is 15,000 psi and the operating temperature range is from -40 °C to 150 °C.

The Red Eye® Subsea water-cut meter derives the measurement from NIR absorption spectroscopy where different phases such as water, oil, natural gas, and hydrate inhibitors have unique absorption profiles. NIR is particularly well suited to detect and quantify hydrocarbons and water due to the overtone absorption bands for O-H and C-H bonds. Furthermore, since the absorption is based on the water molecule itself, there is no sensitivity to water chemistry issues like salinity.

The meter has five wavelength bands optimized for measuring relative concentration of oil, water, and, methanol (Figure 3). Additionally, the strong absorption peak of water at 1950 nm relative to all other components provides unparalleled water detection capabilities that are insensitive to gas or liquid hydrocarbon properties.

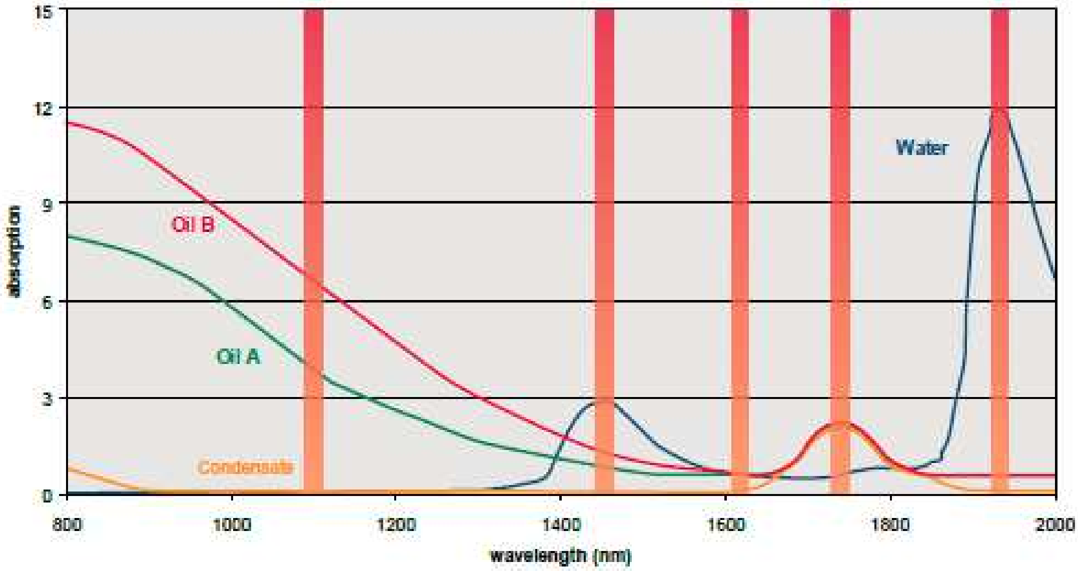

Figure 3 – Typical wavelengths for Red Eye® Subsea water-cut meter.

The meter's internal algorithms calculate relative concentrations based on individual component calibrations via sophisticated chemometrics. The absorption profile for natural gas can be assumed to be zero for all channels at low pressures less than 500 psi (34.5 bar). At higher pressures, gas absorbance starts to play a minor role but it is linear with pressure and easy to accommodate. Typical changes in gas composition do not affect the measurement.

In high GVF streams the liquid tends to flow along the pipe wall. By positioning the sensor gap at the pipe wall, the Red Eye® Subsea water-cut meter can accurately characterize the liquid even when the concentration is low relative to the gas content. Importantly, calibrations are robust and need not be repeated for modest density changes in the phases.

3.2 In-Well Optical Flowmeter Operating Principle

The in-well optical flowmeter was introduced into the oilfield in 2000 and has been proven as a reliable, accurate, and highly repeatable flow measurement device. The flowmeter itself is a key component of a PDMS which may also include one or two optical P/T gauges, optical array temperature sensing (ATS), and/or optical distributed temperature sensing (DTS) systems. Weatherford's PDMS has been designed with the philosophy of having low complexity and passive components downhole while keeping active electronic equipment on the surface to ensure high reliability and measurement accuracy. The optical flowmeter is typically built as a single integrated assembly with a two-phase flowmeter and a P/T gauge. A typical PDMS system consisting of a top-side instrumentation rack and a downhole flowmeter is shown in Figure 4.

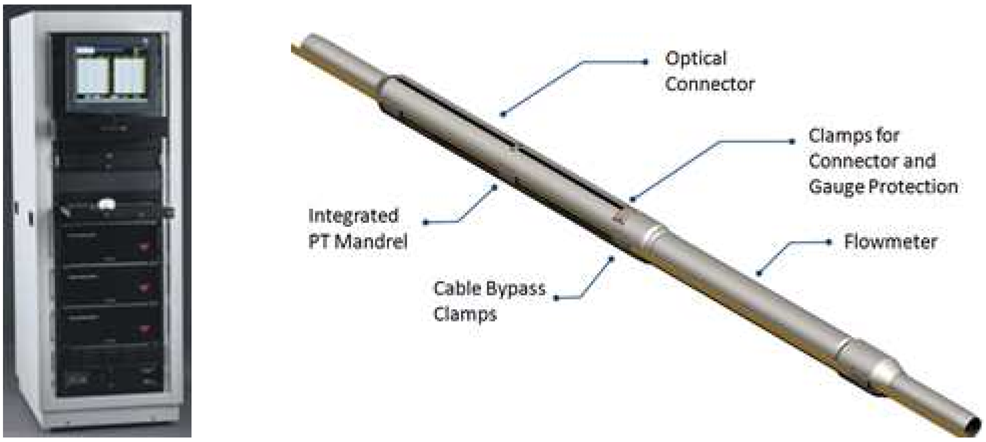

Figure 4 – Fiber-optic flowmeter.

The optical flowmeter is non-intrusive, full-bore (i.e., no permanent pressure loss), and has high resilience to erosion and corrosion. It has no exposed sensors, moving parts, or downhole electronics. Flow measurement is bidirectional, making the flowmeter a valuable tool for producer and injector wells.

The in-well flowmeter is optically attached to surface instrumentation where the flow signals are processed by a flow computer. The system is capable of transmitting optical signals to distances up to 25 km. This gives the flexibility of using the in-well optical flowmeter in combination with subsea equipment by utilizing umbilicals that include fiber. A flow algorithm located in the computer uses a parameter file in which the single-phase properties for a given fluid flow are listed as PVT tables for a range of pressures and temperatures. The single-phase properties include speed of sound (SoS) tables for the individual phases as well as other pertinent information such as density, viscosity, and volume formation factors. Because all these values are different for each application, they need to be determined based on PVT analysis of bottomhole fluid samples. A full and recent PVT report is one of the requirements that the operator is expected to provide.

3.2.1 Flowmeter Size, P/T Ratings, and Material Options

The optical flow measurement technology is applicable to any pipe size. However, there are some standard sizes that are commonly used. These standard sizes are listed in Table 1 below.

Table 1 – Standard Sizes and Minimum Flow Rates for Optical Flowmeters

Size	Weight	Minimum ID		Maximum ID		Standard OD		Minimum Flow Rate	
[in.]	[lbm/ft]	[in.]	[mm]	[in.]	[mm]	[in.]	[mm]	[B/D]	[m^3/D]
2-3/8	4 to 5.8	1.867	47.4	2.041	51.8	4.375	111.1	960	153
2-7/8	6.4 to 8.6	2.259	57.4	2.441	62.0	4.875	123.8	1,400	225
3-1/2	9.2 to 10.2	2.922	74.2	2.992	76.0	5.500	139.7	2,350	375
4-1/2	12.75 to 15.1	3.758	95.5	3.958	100.5	6.500	165.1	3,900	620
5-1/2	17 to 20	4.778	121.4	4.892	124.3	7.500	190.5	6,300	1,000

The minimum flow rates in Table 1 were calculated based on a conservative 1 m/s water flow velocity under standard conditions. Depending on the fluid density, the minimum flow rates will change. Two different material options are available for the optical flowmeter: a standard version which uses Super Duplex 25 Chrome and a high-pressure/high-temperature (HP/HT) version which uses Inconel 718. The HP/HT version is used for demanding applications such as deep water. The material options and the corresponding P & T ratings are given in Table 2.

Table 2 – Material Options for Standard and HP/HT Versions

Material	P Rating	Operating T	Storage T
Super Duplex 25 Chrome	690 bar (10,000 psi)	25°C – 125°C (77°F–257°F)	-50°C – 125°C (-58°F–257°F)
Inconel 718	1000 bar (14,500 psi)	25°C – 150°C (77°F–302°F)	-50°C – 150°C (-58°F–302°F)

3.2.2 Measurement Physics

The flowmeter technology is based on turbulent flow measurements inside the tubing at the point of the sensor. Turbulent pipe flow contains self-generating turbulent pressure fluctuations that convect at a velocity near the volumetrically-averaged flow velocity. These pressure fluctuations (sometimes called vortices or eddies) are of different length scales from the smallest Kolmogorov scale to the largest pipe diameter and remain coherent for several pipe diameters as they convect with the flow through the pipe (Figure 5). This process repeats itself as new vortices are continuously generated by frictional forces acting between the fluid and the pipe wall as well as within the fluid itself. As these vortices convect with the flow through the pipe, their sound waves also propagate at the sonic velocity in both upstream and downstream directions.

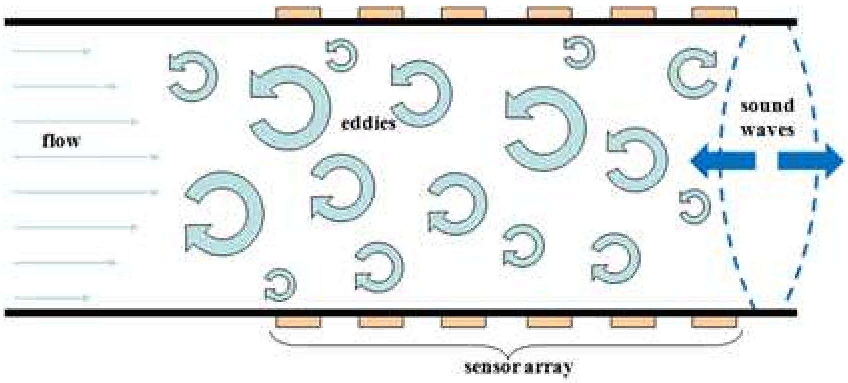

Figure 5 – Turbulent pipe flow: eddies convecting in flow direction while their sound waves propagate in both directions.

In a turbulent pipe flow, the pressure at any time consists of two components: a static component and a dynamic component due to turbulent flow (Figure 6). Typically, the downhole static pressure component could be in the order of 10 million Pa while the dynamic pressure component could be in the order of 100 Pa. The static component is a function of flowmeter's position in the well and reservoir conditions, whereas the dynamic component requires flow motion and is typically a result of the turbulent fluctuating velocities of the convecting vortices. It is this dynamic pressure by these vortices or their sound waves that cause local changes in the radial strain of the pipe wall.

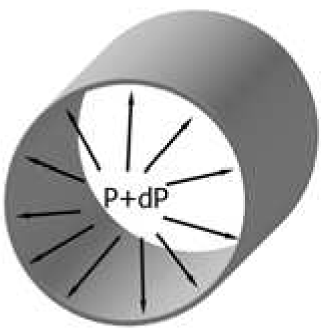

Figure 6 – Pipe is exposed to static and dynamic pressures.

The strain of the pipe circumference is captured by an array of optical sensors externally mounted onto the sensor tube. This strain amount is then converted to a physical pressure and fed into an advanced array processing algorithm from which the time of flight between the sensors for the vortices and their sound waves are determined. The velocity of the vortices and the SoS of the fluid mixture are then calculated based on the time of flight and the known distances between the sensors.

3.2.3 Phase Flow Rates

Once the flow velocity is determined, the total volumetric flow rate can be calculated by the product of the corrected velocity and the flowmeter cross-sectional area. The total flow rate does not provide information on what is flowing through the pipe if the flow is a mixture of two or more phases. To determine the phase flow rates in a two-phase flow, the measured SoS information is used. Example plots for gas/liquid (G/L) and liquid/liquid (L/L) flows showing the variation of SoS as a function of WLR or liquid hold up (HL) are given in Figure 7: the upper plot shows the L/L case in which the left and right y-axes denote the single-phase oil SoS and water SoS, respectively. The lower plots show two G/L cases in which the left y-axis denote the single-phase gas SoS. The L/L plot shows a quadratic variation but the SoS is unique for a given mixture, whereas the G/L plot appears more challenging as for some SoS measurements do not yield a unique solution. In this case, the solution domain must be selected based on independent knowledge of the field (i.e., gas-rich or liquid-rich application) to resolve the phase flow rates correctly.

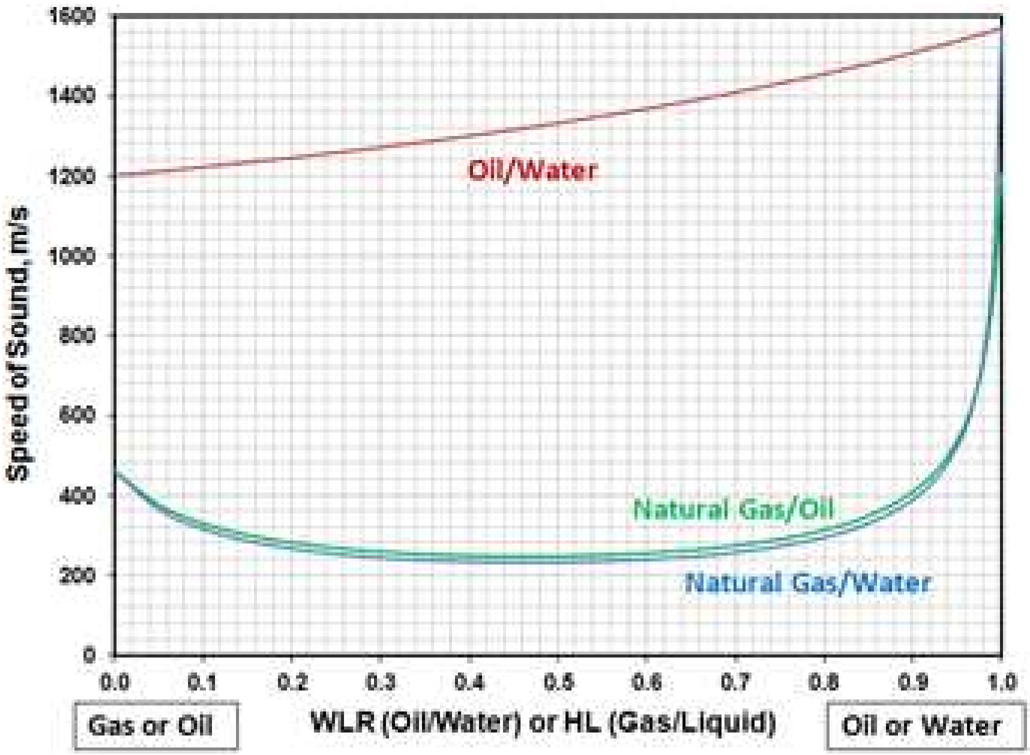

Figure 7 – Two-phase SoS variation with WLR or HL for L/L and G/L cases.

The optical flowmeter can also resolve three-phase flows in the absence of Red Eye® water-cut meter, but the solution requires a more complex treatment since additional information is necessary: in this particular case, flowmeter makes density measurement in addition to the required two-phase measurements of velocity and SoS. To achieve this, a two-phase flowmeter is used in combination with a secondary P/T gauge installed at a vertical distance of about 100 m from the flowmeter. By measuring the ΔP between the P/T gauges and relating it to the hydrostatic pressure and the frictional pressure drop, the density of the mixture can be calculated through an iterative process. The solution is restricted to vertical or near-vertical wells and additional requirements are necessary for flow conditions (non-slug, well-mixed flows). An example of SoS/density variation of a three-phase oil/water/gas mixture is shown in Figure 8. The three-phase solution domain is depicted by the three-phase envelope bounded by the two-phase solution curves marked as oil/water, gas/oil, and gas/water. The solution domain also includes contours of HL and WLR. The WLR contours intersect the oil/water two-phase curve at 20, 40, 60, and 80% WLR values from left to right. The HL contours represent 60, 70, 80, 90, 95, and 98% HL values from bottom to top. An arbitrary three-phase measurement point is also plotted between 20 – 40% WLR and 95 – 98% HL contours. The HL is defined by the volume amount of liquid in the total volume of the mixture, whereas WLR is defined by the volume amount of water in the total liquid volume.

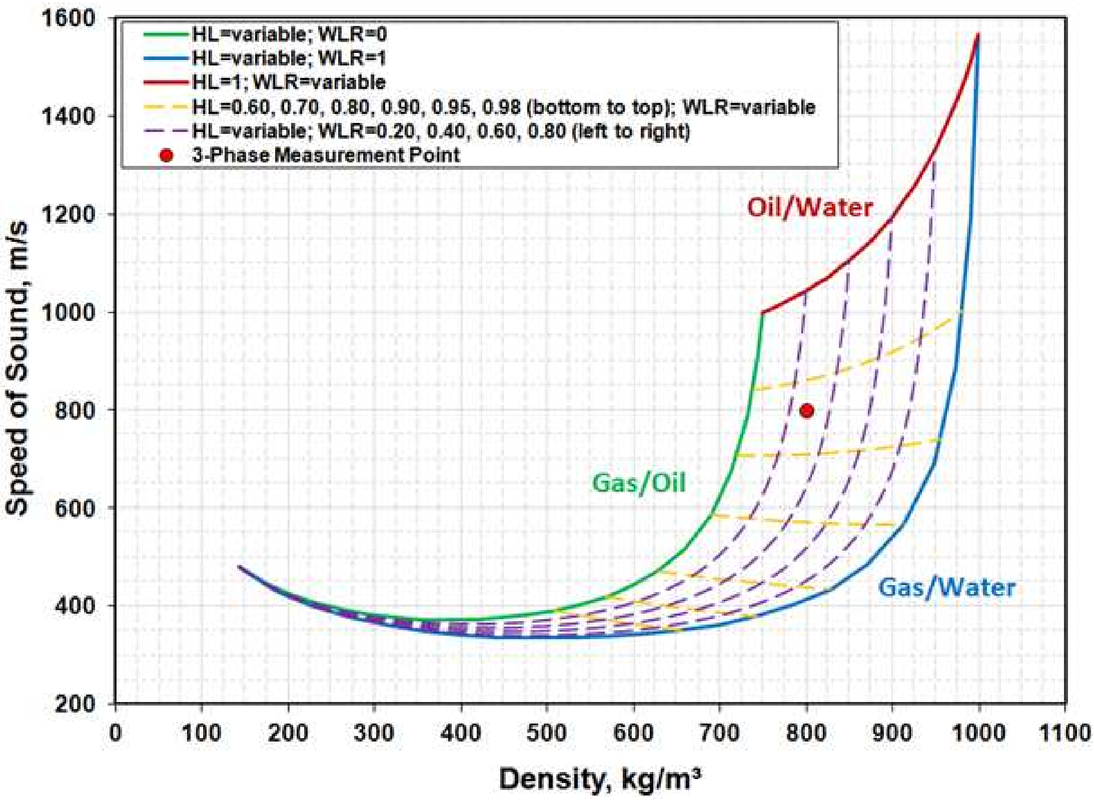

Figure 8 – Example of SoS/density plot for three-phase flow (oil, water, and gas).

As shown in the plots in Figure 8, a given SoS and density measurement pair correspond to a specific HL and WLR pair. The three-phase measurement approach is then based on measuring the SoS and the density of the fluid mixture and determining the corresponding HL and WLR. In closed form, the HL and WLR can be represented by the following functional forms:

$$HL = f\left(SoS, \rho_m, \rho_o, \rho_w, \rho_g, a_o, a_w, a_g, r, t, E\right)$$
$$WLR = f\left(SoS, \rho_m, \rho_o, \rho_w, \rho_g, a_o, a_w, a_g, r, t, E\right) \quad \textbf{(Eq. 1)}$$

where r, t represent pipe geometry (radius and thickness) and E represents pipe material (modulus of elasticity). The SoS and mixture density (ρ_m) measurements along with the known densities of individual phases (ρ_o, ρ_w, ρ_g) as well as the known individual phase speed of sounds (a_o, a_w, a_g) allow the direct calculation of HL and WLR. Once the HL and

WLR are determined, the volumetric phase flow rates can be calculated from the following functional expressions:

$$\begin{aligned} Q_0 &= f\left(HL, WLR, V, A\right) \\ Q_w &= f\left(HL, WLR, V, A\right) \\ Q_g &= f\left(HL, V, A\right) \end{aligned} \quad \textbf{(Eq. 2)}$$

where V is the measured and calibrated flow velocity and A is the cross-sectional area of the flowmeter conduit. The standard flow rates are then obtained by means of the PVT tables.

4 SUBSEA FLOWMETER – COMBINED SYSTEM

A new approach in subsea multiphase flow measurement is introduced. The approach combines two robust and field-proven Weatherford technologies:

1. **Water-cut measurement:** NIR water-cut measurement technology which is capable of measuring water and oil concentrations in multiphase flow with up to 99.5% gas volume fractions.

2. **Flow measurement:** In-well fiber-optic flow measurement technology capable of resolving gas and total liquid flow through the measurements of flow velocity, fluid mixture SoS, and absolute pressure and temperature at meter location. The in-well flowmeter itself is non-intrusive, full-bore with no permanent pressure loss, and has high resilience to erosion and corrosion.

A schematic of the subsea multiphase flowmeter system is shown in Figure 9. The Red Eye® Subsea water-cut meter positioned at the subsea wellhead makes precise measurements of water cut in any multiphase stream, and dynamically sends this information to the optical flowmeter's computer at the offshore platform or floating production facility. The flow computer then utilizes this information along with the in-well measurements of velocity, SoS, pressure, and temperature. This hybrid system consisting of water-cut measurements at the subsea wellhead and flow measurements in the well represents a novel approach in subsea multiphase flowmetering that may offer significant advantages to traditional systems for some applications. The solution is valid for all orientations from vertical to horizontal configurations.

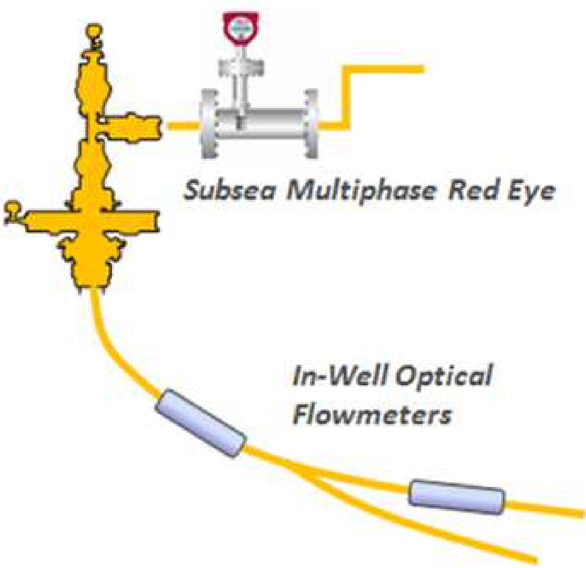

Figure 9 – Schematic of subsea multiphase flowmeter system.

The new approach is illustrated in Figure 10. Unlike the existing approach described in the previous section, the density of the fluid mixture is not measured in this new approach. The flowmeter measures the velocity but receives the WLR information from the Red Eye® water-cut meter located at the subsea level. Hence, we will denote this water-cut value as WLR_{ss}. The WLR_{ss} is expected to be different from the in-situ WLR at the location of the in-well flowmeter. However, WLR_{ss} can be converted to in-situ WLR using a PVT model. The corresponding density value at which the measured SoS and $WLR_{in\text{-}situ}$ curves intersect defines the density of the fluid mixture. For some SoS values, there are not unique mixture densities. In addition to the water-cut determination, the Red Eye® meter also provides a qualitative measure of the G/L ratio at the sensor. This measurement can be used to determine which side of the SoS/density curve applies. After implementing a multiphase slip model between the gas and liquid phases, the corresponding phase flow rates can be determined.

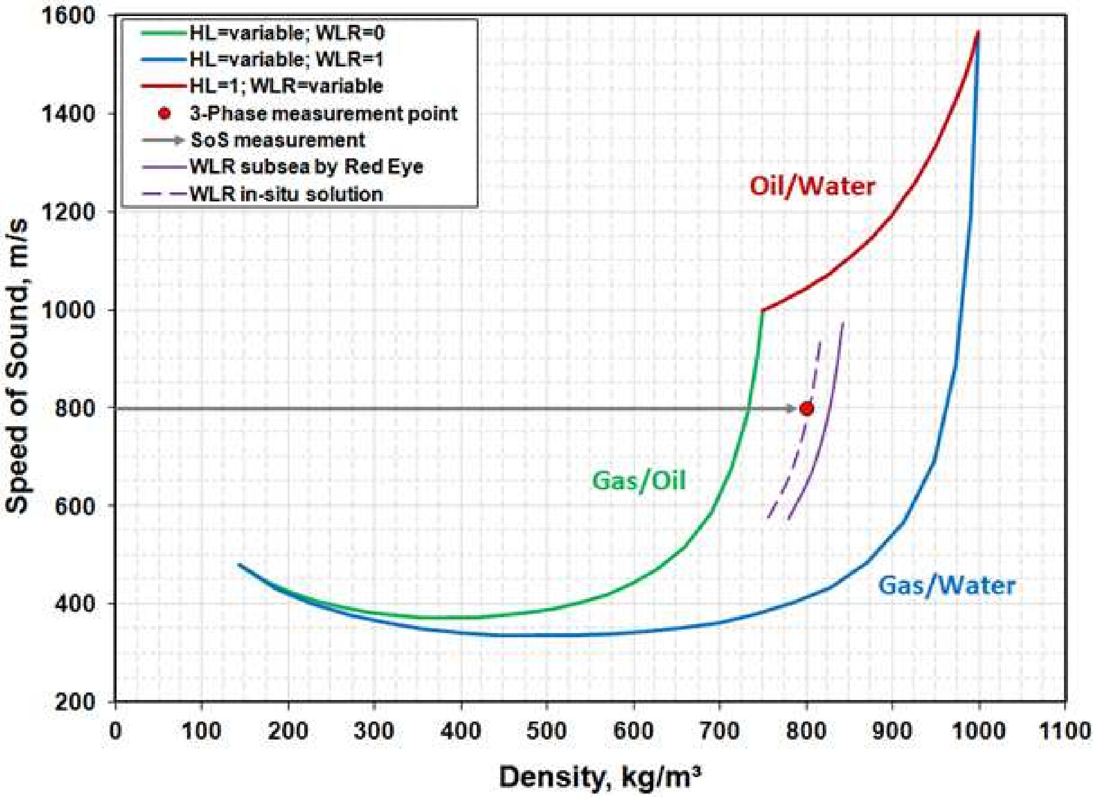

Figure 10 – Schematic of the new approach used in subsea three-phase flow measurement.

A flow diagram showing the process for the new approach is shown in Figure 11. The subsea flowmeter consists of a Red Eye® Subsea water-cut meter installed at the subsea level and a two-phase optical flowmeter integrated with a P/T gauge installed in the well. The WLR_{ss} is measured by the Red Eye® meter; the in-situ pressure and temperature are measured by the P/T gauge; and flow velocity and SoS of the fluid mixture are measured by the two-phase optical flowmeter. Once all the information is obtained from the components, the in-situ water cut is calculated from a PVT model. The mixture density is then estimated as a function of HL by the following expression:

$$\rho_m = f\left(HL, WLR_{in-situ}, \rho_o, \rho_w, \rho_g\right) \qquad \textbf{(Eq. 3)}$$

The estimated mixture density is then used in its functional "HL" form in the SoS equation [17] and the corresponding HL is calculated from a second order quadratic equation:

$$HL = f\left(SoS, WLR_{ss}, \rho_o, \rho_w, \rho_g, a_o, a_w, a_g, r, t, E\right) \quad \textbf{(Eq. 4)}$$

In the next step, a multiphase slip model is implemented between the liquid and gas phases. The liquid and gas superficial phase velocities are estimated and the in-situ phase flow rates are calculated. This process is followed by the calculation of the phase flow rates for the standard conditions at the surface.

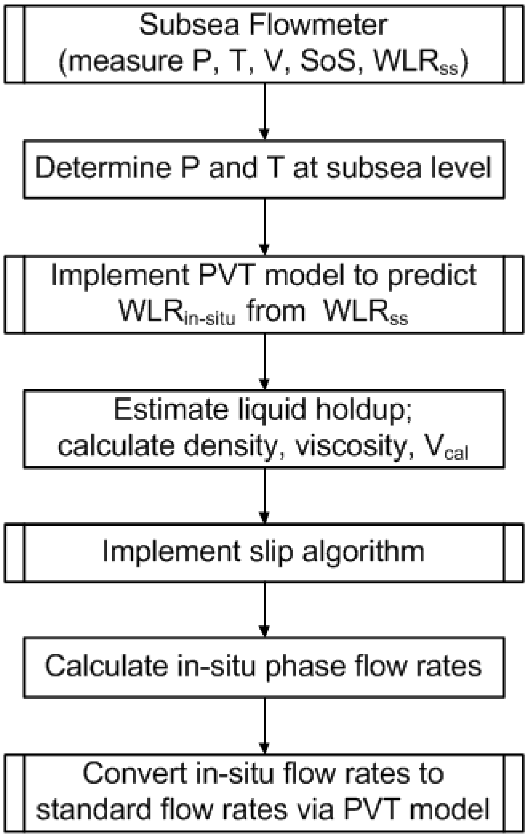

Figure 11 – Schematic of solution method.

4.1 Advantages of the New Solution

Current subsea multiphase flowmetering solutions have some similar components based on the same technology. For example, they all include a Venturi section for flow rate measurement and various versions of gamma-ray sources for phase fraction or density measurement. Although these components have been proven in the field, it is also known that they have some fundamental issues associated with their design. The new solution should provide significant advantages over the existing subsea multiphase flow measurement solutions. Some of the advantages of the new solution are listed below:

1. **Non-nuclear:** Most subsea flowmeters have gamma-ray detectors which are based on nuclear technology. This approach introduces regulatory concerns, potential export/import difficulties, special training requirements, as well as potential liability issues. Furthermore, these devices are not immune to failures [18]. One less obvious disadvantage of nuclear-based tools is their lifetime. For example, Cesium-137, which is frequently used in these devices, has a half-life of 30 years. Manufacturers often quote a useable lifetime of 15 years. The new solution, on the other hand, is based on robust and field-proven turbulent flow measurements and eliminates all the issues pertinent to nuclear devices.

2. **Zonal measurement:** One of the main advantages of the new solution is its ability to determine zonal production rates in multizone applications. The in-well optical flowmeter can be placed in each zone or a combination of flowmeters can be arranged in an efficient way to determine the contribution of each zone as well as the total contribution of the well.

3. **Production optimization:** Today's intelligent completions use ICDs or ICVs to achieve evenly distributed flow, especially along horizontal wells, to avoid or minimize production problems including water or gas coning, and sand production. Flowmeters installed in a multizone application provide the phase flow rates that can be used to determine the optimum settings for ICVs which help optimize the production in real-time.

4. **High turndown ratio:** Unlike the limited flow rate range of differential pressure measurement devices such as Venturi, the new solution does not have a practical high limit and can easily surpass a turndown ratio of 30, about three times more than a Venturi. The in-well component is a part of the tubing with no blocking of the flow, therefore, when the high limit is reached, it is not because of the measurement limit of the meter but because of the frictional losses in the entire tubing due to high velocities.

5. **Bidirectional measurement:** The bidirectional flow measurement capability of the new solution is also a testimony to the robustness of the technology it is based on. True to the "intelligent completion" concept, it is possible to detect cross-flow between different zones or to change service from producer to injector regardless of the type of fluid injected (liquid or gas) with no hardware/software changes. The bidirectional flow measurement is a unique feature that most other flow measurement technologies are not capable of doing even at the surface.

6. **Less-intrusive:** Most subsea multiphase flowmeters include a Venturi component as the primary design which causes significant pressure loss due to the restriction of the flow. Furthermore, because of the change in the cross-sectional area, the dynamic pressure due to flow on the converging Venturi section coupled with potential impingement of sand or other solid content in the flow may cause corrosion and erosion in the material and change the characteristics of Venturi over time. As a result, the performance is affected adversely. The in-well component of the new solution does not have any obstruction or area change thus the performance is not affected due to corrosion or erosion. Also, Red Eye® meter's probe at the subsea level does not cause significant pressure drop. There are no ΔP measurements and no associated pressure taps which are usually susceptible to potential problems due to their exposure to flow.

7. **Solid-tolerant measurement:** The in-well component of the subsea flowmeter is insensitive to reasonable amount of solid content. Flow loop tests with sand have shown that no significant differences were observed in the spatio-temporal spectral analysis of test data when reasonable amount of sand is present in the flow. In one of the tests, injection of 100 g/s of sand into a water flow of 2200 m^3/D did not reveal any adverse effect: the magnitude of attenuation was too small to have a significant effect on the flow measurement. The effect of solids in SoS measurement was also minimal at those rates. The insensitivity to solids makes this flowmeter technology suitable for many field applications.

8. **Optical in the well:** The in-well component of the new flowmeter is based on fiber-optic technology and does not have the shortcomings of the electronic-based sensors from reliability, survivability, and longevity perspectives.

9. **Cost savings:** The lifetimes of electronic equipment as well as the drift in their measurements are some of the primary reasons that subsea flowmeters also have retrievable versions or redundant sensor arrangements that increase the cost significantly. The new solution should provide significant cost reduction for the market

when compared with most subsea multiphase flowmetering systems.

In addition, the new solution is relatively easy to implement when compared with Weatherford's existing three-phase solution for near-vertical wells. The new subsea multiphase flow measurement approach offers the flexibility of three-phase flow measurement in any orientation from horizontal to vertical in a subsea environment. Furthermore, the water-cut measurement at the subsea level removes the requirement for in-well density measurement through the frictional pressure drop arguments of the existing approach. This in turn reduces the need for the hardware requirement in the well (i.e., no secondary P/T gauge), provides a more local flow measurement capability with improved completion logistics (i.e., no need for a 100 m vertical separation for the second P/T gauge), and potentially improves the in-situ flow measurement accuracy.

Weatherford's in-well optical flowmeter system is capable of transmitting optical signals to distances up to 25 km. This gives the flexibility of using the in-well optical flowmeter in combination with subsea equipment by utilizing umbilicals that include fiber. Based on Weatherford's internal data, 90% of the installations have a stepout distance of 20 km or less. Recent JIP data also support a similar picture: more than 70% of the installations having stepout distances of 20 km or less. This indicates that the capability of the optical system aligns well with the current and future market needs.

We have discussed the fiber ratio in subsea umbilicals for the new and existing installations with personal contacts from operators. It is estimated that all new subsea developments have fiber communication and the umbilicals are prepared to accommodate fiber connections. For the existing installations, it is also estimated that 40% of the umbilicals have fiber and about half of them are accessible.

The interest in subsea developments and the use of fiber communication have been steadily increasing, laying the foundation for the technologies involving fiber-optic measurements. The authors believe that the new subsea multiphase flow measurement solution described in this work offers unique advantages when compared to the other solutions in the market.

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6 NOTATION

A	Flowmeter sensor pipe cross sectional area, [m^2]
a_o, a_w, a_g	Single-phase speed of sound of oil, water, and gas [m/s]
DTS	Distributed Temperature Sensing
E	Pipe modulus of elasticity, [Pa]
GVF	Gas Volume Fraction, [-]
HP/HT	High Pressure / High Temperature
ICD	Inflow Control Device
ICV	Inflow Control Valve
JIP	Joint Industry Project
MP	Multiphase
NIR	Near-Infrared
P/T	Pressure / Temperature
PDMS	Permanent Downhole Monitoring System
PVT	Pressure / Volume / Temperature
Q	Volumetric flow rate, [m^3/s], [m^3/hr]
r	Flowmeter sensor pipe radius, [inch]
SoS	Speed of Sound, [m/s]

t	Flowmeter sensor pipe thickness, [inch]
V	Velocity, [m/s]
WAG	Water Alternating Gas
WLR	Water-in-Liquid Ratio, [-]
WLR_{ss}	Water-in-Liquid Ratio at the subsea level, [-]
$WLR_{in\text{-}situ}$	Water-in-Liquid Ratio at the in-well optical flowmeter, [-]
ρ_o, ρ_w, ρ_g	Single-phase density of oil, water, and gas [kg/m^3]

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