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A PROTOTYPE WET-GAS AND MULTIPHASE FLOWMETER

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ABSTRACT

A wet-gas flowmeter based on the field-proven downhole fiber-optic multiphase flowmeter has been developed. The flowmeter is based on an extended throat Venturi-nozzle and a Sonar flowmeter. This combination exploits the characteristics of these two devices in wet-gas flows. For the Venturi, there is a well-defined and large over-reading with increasing liquid-loading, whereas this has a significantly lower impact on the total flow rate measured by Sonar.

The Sonar-Venturi wet-gas flowmeter has been in development over the past several years and has been tested extensively in industry flow loops. Particular emphasis has been placed on developing a flowmeter with a broad operating envelope that includes a large span of fluid properties, a high turndown ratio, and well characterized response both within and outside its intended operating envelope. The wet-gas performance has been demonstrated at the recently commissioned CEESI 3 phase wet-gas flow loop, yielding total and gas flow rates better than ±5%,[*] liquid flow rate better than ±0.5 m^3/hr in Type I wet gas,[1] and better than ±20% in Type II wet gas. A Red Eye 2G near-infrared (NIR) water cut meter is used to differentiate the oil/condensate and water. The Red Eye 2G has field proven performance in low gas volume fraction (GVF) flows for full range of water cut. A prototype version has demonstrated ±5% water cut uncertainty in high GVF multiphase[2] flows and initial testing of the Red Eye in wet-gas flows is showing great promise.

The wet-gas flowmeter was also tested at the NEL multiphase flow facility to evaluate whether the measurement capability could be extended beyond the wet-gas envelope. Although the performance in low-pressure multiphase flows did not match the performance seen in high-pressure wet-gas flow, measurement capability was maintained and reasonable performance was demonstrated for the entire range of GVF.

INTRODUCTION

Test separators and portable well testing services are the most common technologies used to generate a measurement snapshot, typically every 30 days, but often less frequent. It is, however, widely accepted that real-time individual wellhead production monitoring is an effective tool to monitor the health and maximize the performance and ultimate recovery of producing oil and gas wells. Measurement technologies have been developed to monitor individual wells in real-time; however, the high cost has generally limited the install base to prolific wells or multiple wells multiplexed with multi-port selector valves. Furthermore, many are being used as mobile well-testing devices. Other factors complicating wide implementation include limited operating envelope, fragile mechanical and sensing characteristics, and sensitivity to changes in fluid chemistry or composition. To date, only a few meter types claim to operate both in wet-gas and

[*] All performance numbers quoted herein are relative measurements with 95% confidence interval, unless otherwise noted.

multiphase regimes. Most other wet-gas or multiphase meters may report highly erroneous results outside their intended operating range. Therefore, as wells mature with increasing gas fractions and water cut, the flow measurement conditions at the wellhead necessitate flowmeters with a wider operating envelope and a lower sensitivity to compositional changes than is available today.

The Sonar flowmeter technology platform offers the potential for a cost-effective and robust flowmeter with a broad operating envelope that may bridge the gap between traditional multiphase flowmeters and high gas-fraction metering. Sonar flow measurement is derived from the field-proven downhole fiber optic multiphase flowmeter.[3-5] It is non-intrusive, has no wetted sensors and offers excellent resilience to erosion and corrosion. Sonar flowmeters offer accurate and repeatable flow measurement with a small and well-behaved Reynolds number dependence and a large turndown ratio. Sonar can measure liquid and gas flows with no changes in hardware or software.

The conventional types of differential pressure meters (e.g. Venturi, cone or orifice plate meters) still remain the flowmeters of choice in the vast majority of gas wells. The over-reading of such devices when there is liquid in the flow stream is well understood and documented in literature.[6,7] However, the liquid content can be very difficult to estimate and hence correct for in the field. Consequently, the erroneous readings must be corrected by back allocation. Sonar tends to have a very well-behaved and low over-reading with liquid loading in wet-gas flows. The combination of a differential pressure meter with a Sonar flowmeter therefore offers an over-reading contrast that is exploited to yield the total and gas flow rates and the liquid content.

FLOWMETER DESCRIPTION

The Sonar-Venturi flowmeter is a combination of a Sonar sensor array located in the extended throat section of a Venturi-Nozzle, shown in Fig 1. The higher mixture velocity in the throat is favorable to the passive Sonar array as it improves signal to noise ratio and enhances mixing. The Sonar flowmeter consists of an array of electronic strain gauges (non-fiber optic) combined with fully integrated data acquisition and processing electronics housed in a spool-mounted enclosure. The prototype flowmeter also employs a multivariable pressure, temperature, and differential pressure transmitter for the Venturi. The flowmeter also includes Modbus and diagnostic communications over RS 485 and Ethernet. The entire assembly is powered by 12-36 VDC, consumes less than 10 W, and is Class I, Division 1 compliant.

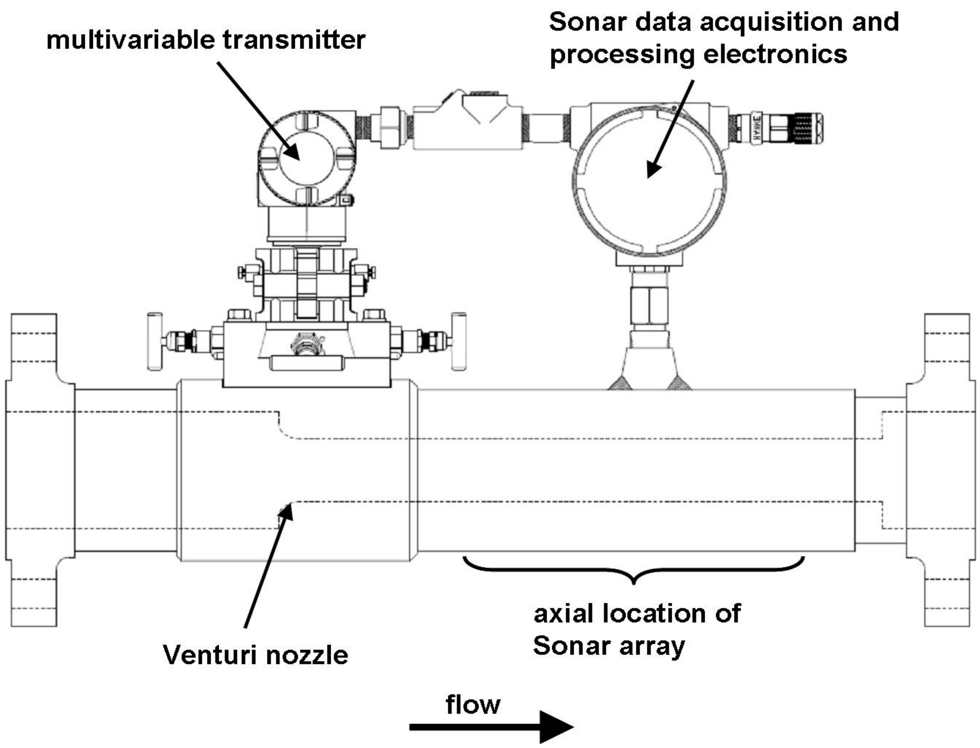

Figure 1 - Sonar-Venturi flowmeter schematic.

Sonar Flowmeter

Turbulent pipe flow contains self-generating vortical structures that convect with the fluid. These vortices remain coherent for several pipe diameters, and they decay as they convect through the pipe. Meanwhile new vortices are continuously generated by frictional forces acting between the fluid and pipe wall and within the fluid itself. An array of circumferentially mounted and axially distributed pressure sensors measures dynamic pressure fluctuations associated with the convecting turbulent eddies. The convection velocity is calculated from the unsteady pressures by array processing algorithms. The volumetric flow rate is directly proportional to the convective velocity measured by Sonar and a single Reynolds number calibration yields a flow rate for liquid or gas. with an uncertainty typically better than ±1%.

The calibrated performance of the Sonar meter in single-phase (oil, water and gas) is presented in Fig. 2. A Reynolds number "turndown" of nearly three orders of magnitude is demonstrated for six different fluids at three different test facilities with no change in the three calibration constants. The calibration values are also consistent with what is typically seen in a fiber-optic flowmeter. In wet-gas conditions, the calibrated Sonar velocity yields a volumetric flow rate that is slightly higher than the actual mixture velocity. The over-reading of Sonar is well behaved with respect to liquid loading and is readily correlated with the Lockhart-Martinelli parameter.

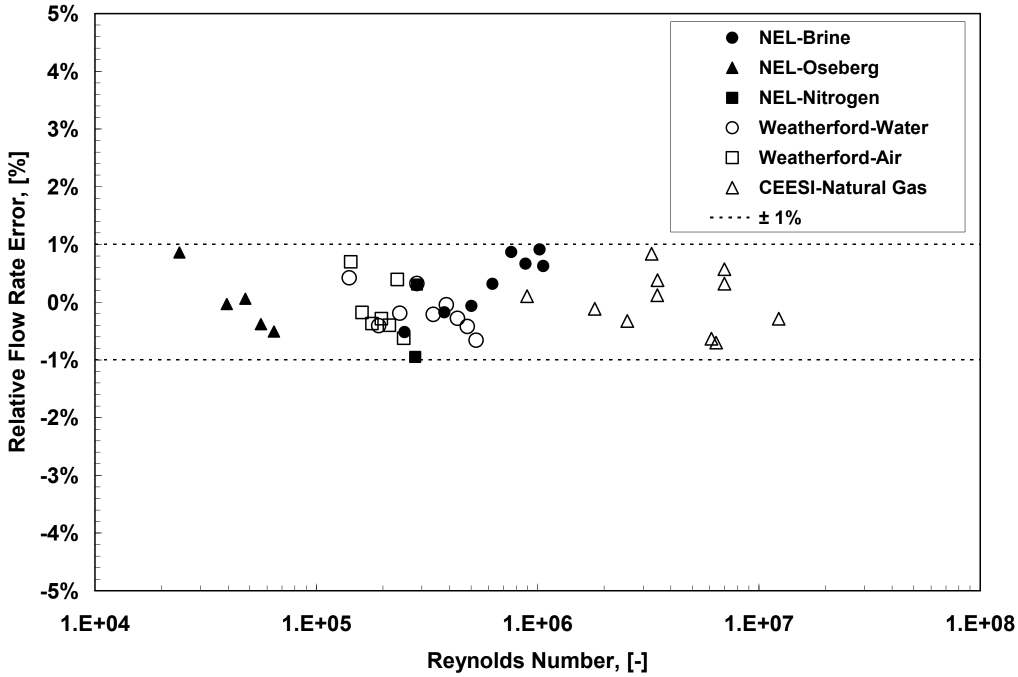

Figure 2 - Baseline Sonar performance over broad Reynolds number range.

Venturi

The extended throat Venturi-nozzle performance was verified with the same dataset and was found to measure single-phase flow rates within ±1.4%. The Venturi behavior is well described in literature. Tests conducted with the Sonar-Venturi combination throughout single-phase, multiphase, and wet-gas flow were consistent with published values of discharge coefficients.

The turndown ratio of the differential pressure sensor is 84:1 from the multivariable transmitter specification sheet. In practice, the wet gas differential pressure on a horizontal Venturi-nozzle was observed to depart from the deLeeuw correlation at pressure turndown ratio of 30:1. Since ΔP is proportional to V^2 the velocity turndown ratio for the Venturi-nozzle is at best 9:1 and, in practice, it can be as low as 5:1. Thus, in terms of flow velocity turndown, the performance of the Sonar meter far exceeds that of the Venturi-nozzle.

Water Cut Meter

The Red Eye 2G water cut meter is based on the principles of spectroscopy and relies on the large difference in the absorption of near infrared (NIR) radiation between oil and water. Differentiation is achieved by operating over a very narrow band of radiation with maximum intensity occurring at wavelengths where crude oil and water exhibit large differences in opacities. The Red Eye measures transmissions at multiple infrared wavelengths simultaneously and calculates the water fraction from the ratio of attenuation at different wavelengths. The technique operates consistently across the full range of 0% to 100% water cut, and is effectively insensitive to free gas.

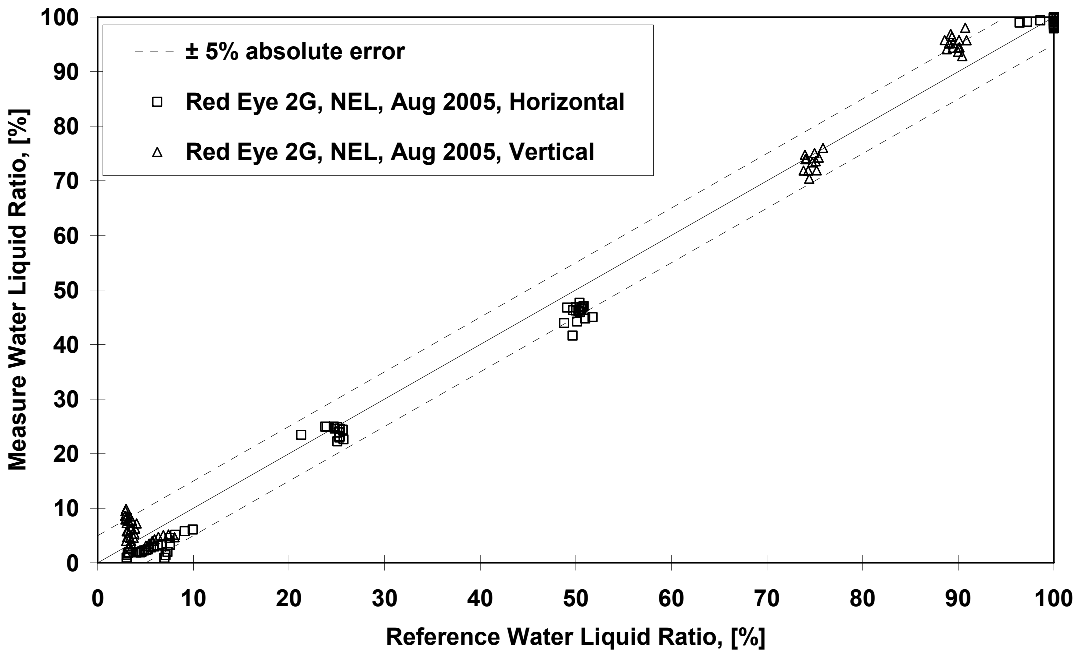

Figure 3 - Performance of water cut measurement.[2]

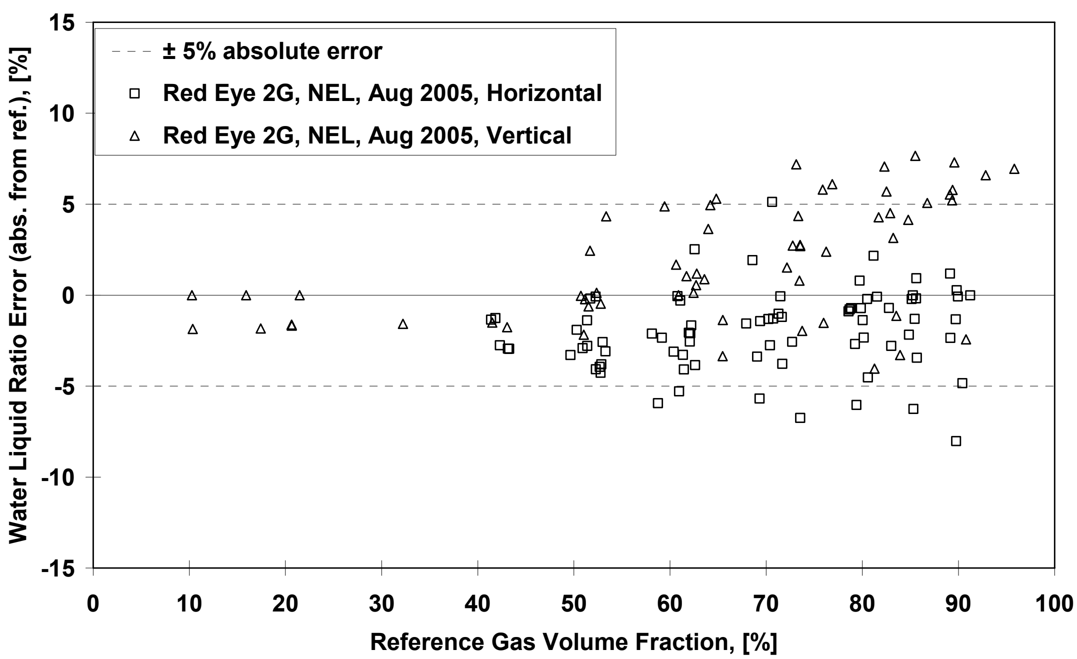

Figure 4 - Performance of water cut measurement for wide GVF range.[2]

Data shown in Figs. 3 and 4 range from 10 to 95% GVF at low pressures.[2] Even those points at the highest GVF do not constitute wet-gas flows with Lockhart-Martinelli parameter significantly higher than 0.3 (due to the low pressure and high liquid/gas density contrast)[1]. However, recent tests conducted at CEESI show very good sensitivity, correlation, and measurement capability in wet-gas flows at GVF up to 99.9%. The water cut measurement has been verified in separate studies and the remainder of the discussion in this paper will focus on the ability to measure liquid and gas flow rates by the Sonar-Venturi combination.

TEST ENVELOPE

The flowmeter was tested at NEL (multiphase) and CEESI (3-phase wet gas) in August and September of 2007 respectively. The CEESI tests were conducted in the recently commissioned 3-phase wet-gas flow loop.

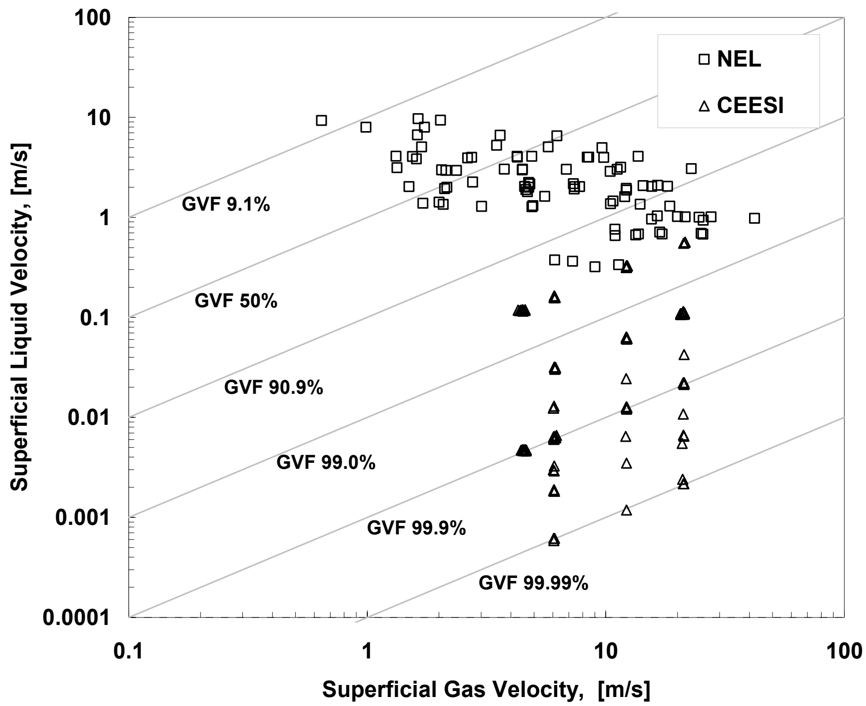

Figure 5 - Phase superficial velocity and GVF variations for NEL and CEESI test matrices.

Figure 5 shows the entire test matrix for both facilities in terms of superficial liquid and gas velocities with no-slip GVF as isolines. From this view, it appears as though the two tests overlap, however, the test pressure at NEL ranged from 2 to 7.5 bar, whereas the test pressures at CEESI ranged from 14 to 55 bar yielding very different liquid/gas density contrasts (see table below). Consequently the high GVF points in the NEL test matrix are not representative of wet-gas conditions because the relatively low gas density results in a relatively low gas Froude number, Fr_g and a relatively high Lockhart-Martinelli parameter, X_{LM}. The CEESI test envelope, on the other hand, covered Fr_g and X_{LM} within the regions defined by API as Type I and Type II wet-gas flow.[1]

	CEESI	***NEL***
Pressure	14, 28, 55 bara	2 – 7.5 bara
Temperature	28-35 °C	22-42 °C
WLR	0 – 100%	1, 40, 75, 100%
GVF (no slip)	97.5-100%	0 - 100%
Total Volume Flow Rate	85-655 m^3/hr	14 – 460 m^3/hr
Liquid/Gas Density Ratio	16 at 55 bara 40 at 28 bara 98 at 14 bara	106 at 7.5 bara 485 at 2 bara
Frg Sonar	1.5 - 20	0.07-2.6
Frg Nozzle	0.5 -5.5	0.02.-0.7
X_{LM}	0 - 0.26	0.3-167
LMQ	0 – 0.72	0-1

WET-GAS TESTS

CEESI Test Facility

The CEESI (Colorado Engineering Experiment Station, Inc.) wet-gas facility, originally built in 1998, was designed for two-phase flow studies consisting of natural gas and hydrocarbon liquids. The loop has been recently redesigned for three-phase operation. Figure 6 shows the block diagram of the three-phase wet-gas loop used for the current tests.

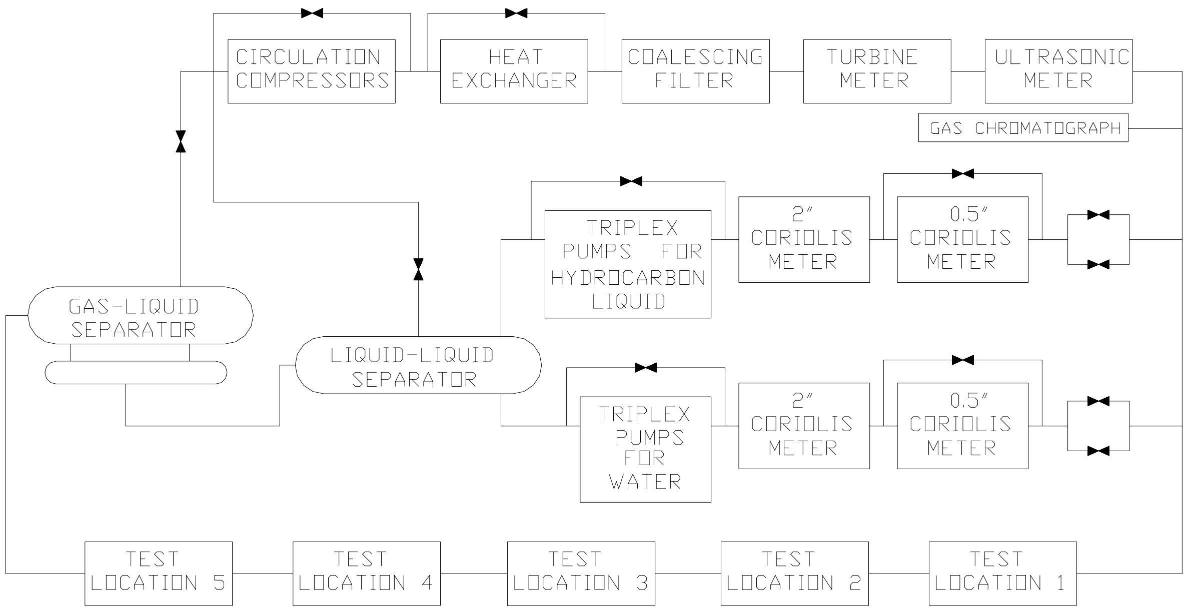

Figure 6 - Block diagram of wet-gas research loop, 4-inch test line

Both a turbine meter and an ultrasonic meter measure the flow rate of the natural gas. The difference in mass flow rate between these two meters is monitored; if the difference exceeds a specified amount, the data is scrutinized for detrimental effects such as pulsation. If the difference is within tolerance, then all other meters installed in the research loop can be compared to the natural gas mass flow rate as measured by the turbine meter. Pressure and temperature measurements at various locations on the loop (including the test locations) are used to calculate local gas density.

The hydrocarbon liquid and the water, which reside in the liquid-liquid separator, can be injected into the gas stream by positive displacement pumps (Triplex pumps). Coriolis meters measure the mass flow rate and the density of the liquids to be injected. The gas stream carries the liquid mixture through the meter test locations and on to the horizontal gas-liquid separator where it is then returned to the liquid-liquid separator. Stability of liquid density, gas composition, pressure, temperature and flow rate is monitored to determine steady state conditions.

During each test point, a gas chromatograph obtains a sample of the natural gas on a 6-minute time interval. Using the average natural gas composition during the test point and the measured pressure and temperature at any given location in the test loop, the gas density at that location is determined using AGA-8. The composition of the gas has some seasonal variation with the methane composition ranging from approximately 83% to 95% during the year. The hydrocarbon liquid (Exxsol™ D80) is very similar to kerosene with less than 2 ppm sulfur.

Figure 7 - Sonar-Venturi flowmeter installed vertically in flow loop.

Figure 7 shows the vertical installation of the Sonar-Venturi flowmeter in the 4-inch wet-gas flow loop. The flowmeter was mounted immediately downstream of a blind T.

Measurement Contrast

The flowmeter has two independent measurements – the Sonar velocity and the Venturi ΔP. It has been established (as evidenced in literature and through tests at multiple flow facilities by the authors) that both instruments measure dry-gas flow-rates very well. In wet-gas flow, it is desirable for each instrument to have an over-reading that is dependent primarily on liquid loading and minimally on other flow parameters such as gas Froude number and line pressure. A modified version of the de Leeuw correlation (developed for horizontal flows) was found to work very well and has been adopted for the Venturi. The basis for the Venturi over-reading (ORV) and subsequent correlation is

$$ORV = \frac{Q_{g,apparent}}{Q_{g,ref}}, \tag{1}$$

with

$$ORV = f_1(X, Fr_g), \tag{2}$$

where the Lockhart-Martinelli parameter is defined herein, as:

$$X = \frac{m_l}{m_g}\sqrt{\frac{\rho_g}{\rho_l}}. \tag{3}$$

The over-reading correlation for the Sonar meter (ORS) was established based on the measured flow velocity and the liquid mass quality (LMQ):

$$ORS = \frac{Q_{t,apparent}}{Q_{t,ref}}; \tag{4}$$

$$Q_{t,apparent} = V_m A; \tag{5}$$

$$ORS = f_1(LMQ, Fr_g); \tag{6}$$

$$LMQ = \frac{m_l}{m_t}; \tag{7}$$

where V_m is the Sonar mixture velocity after applying the Reynolds calibration. A necessary condition for solving for both unknowns (i.e., total flow rate and liquid loading), is to have two independent equations that characterize ORV and ORS.

A convenient way to quantify the independence of the over-reading characteristics is to depict the contrast (i.e., difference in slope) of both over-reading trends. The apparent nozzle gas flow rate and the apparent Sonar bulk flow rate were divided by the reference total flow rate and plotted against X_{LM} in Fig. 8. The contrast between the two trends is what allows for a successful iterative solution for the unknowns.

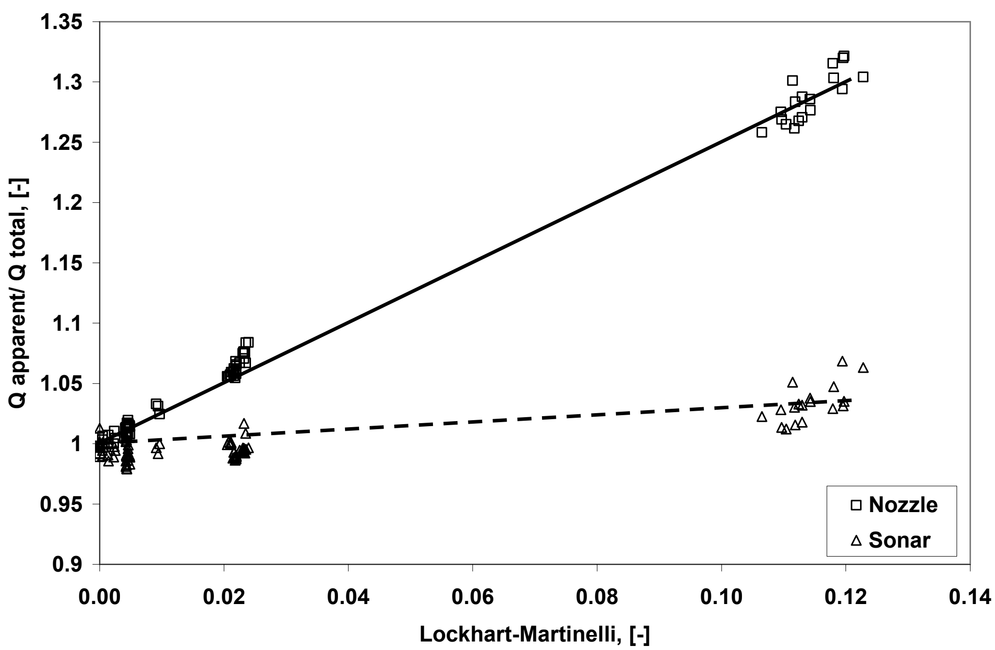

Figure 8 - Difference in slope between the over-reading trends of Sonar and Venturi reveals the contrast between the two devices in wet-gas flow.

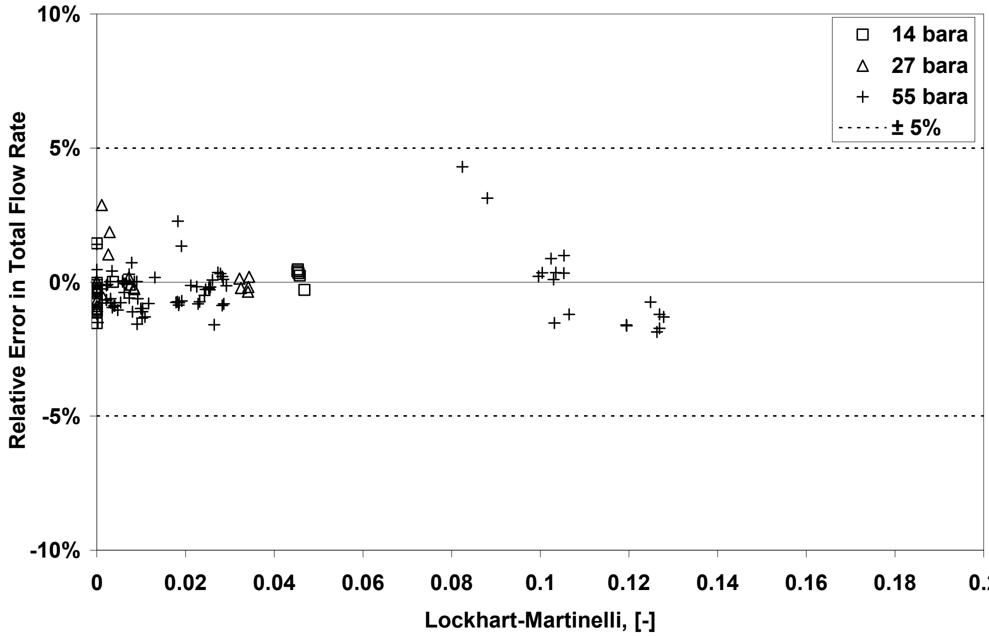

Figure 9 - Total flow rate relative error for wet gas.

Figure 9 shows the total flow rate relative error predicted over all test pressures for the Sonar-Venturi flowmeter. Total flow rate is predicted well within ±5% for the test points across the full range of Lockhart-Martinelli parameter tested. The gas flow rate relative error is shown in Fig. 10. As expected, the gas rate performance follows the total flow rate since the liquid content by volume is negligible for a majority of the test matrix.

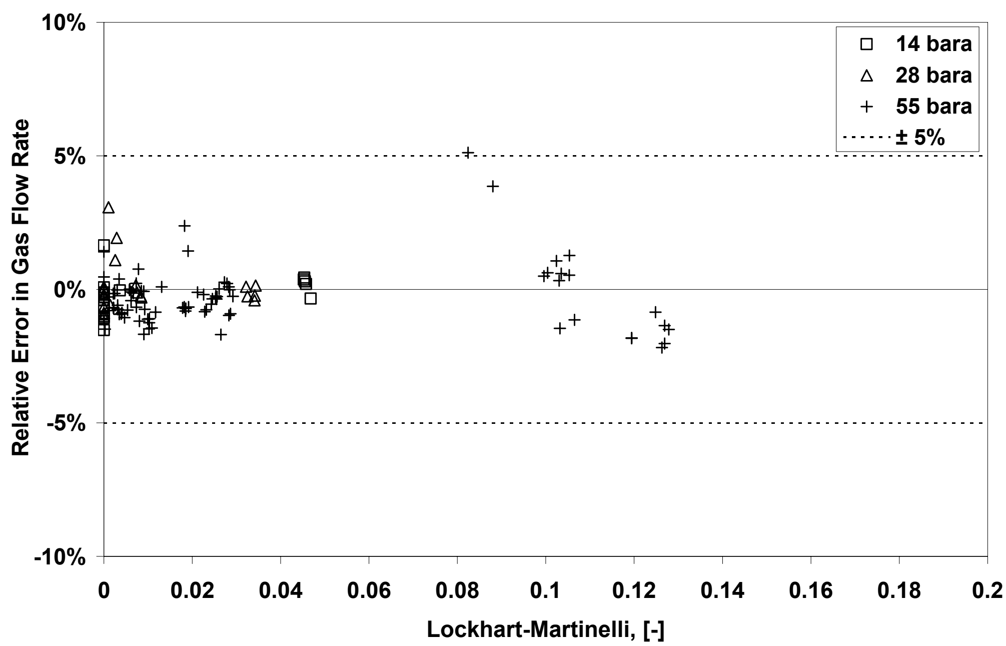

Figure 10 - Gas flow rate relative error for wet gas.

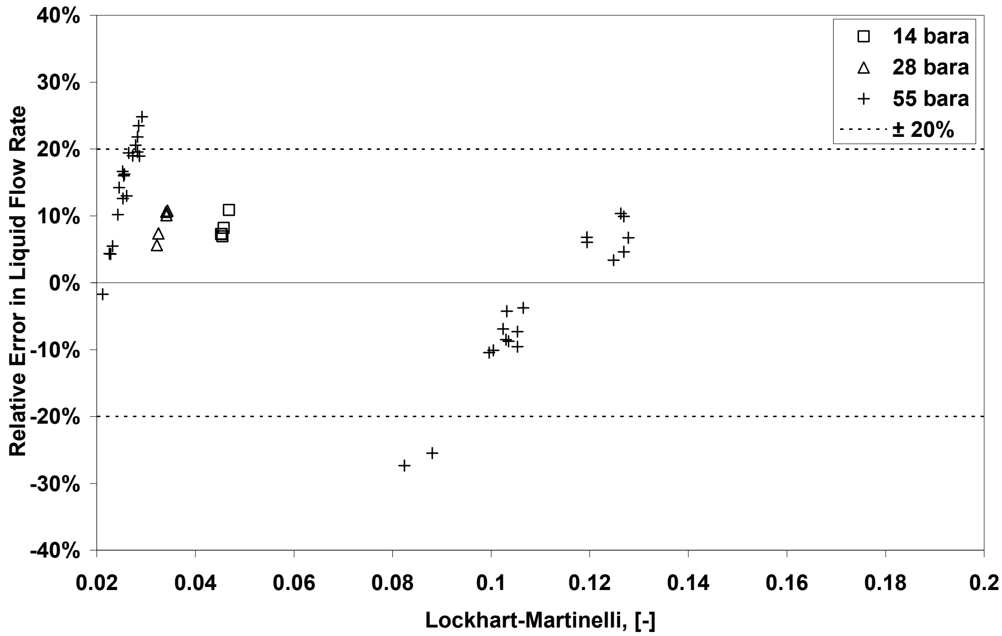

Figure 11 - Liquid flow rate relative error for API Type II wet gas.

Figure 11 shows the relative error in liquid flow rate for API Type II wet gas, defined by having $X_{LM} > 0.02$. The dashed lines show that most of the points are contained within a ±20% relative error band. Figure 12 shows the error in liquid flow rate for API Type I wet-gas flows, where $X_{LM} < 0.02$. In this case the data has been presented in absolute terms and is shown to be within ±0.5 m^3/hr.

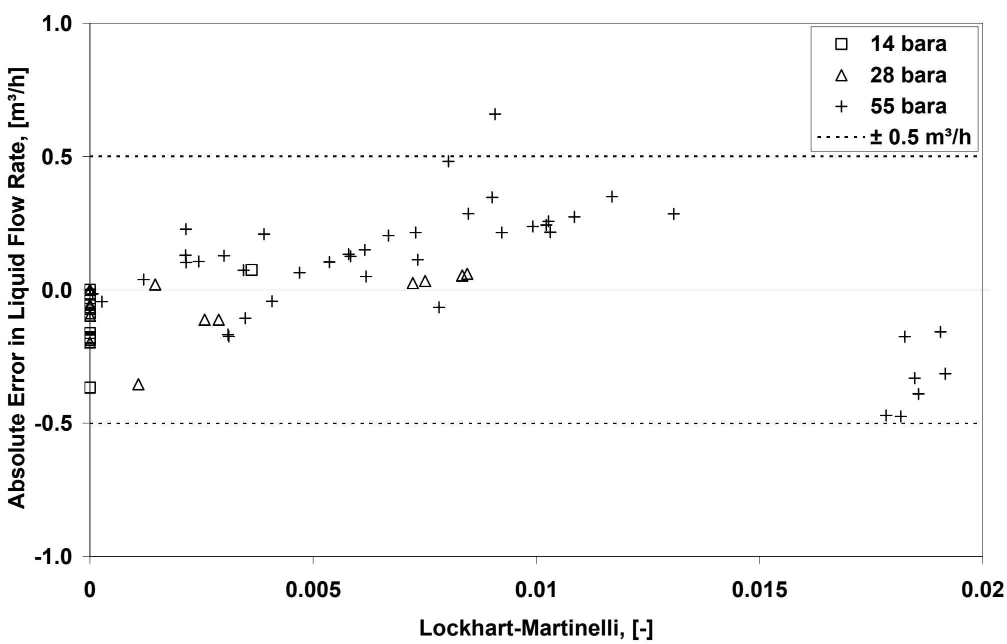

Figure 12 - Liquid flow rate absolute delta for Type I wet gas.

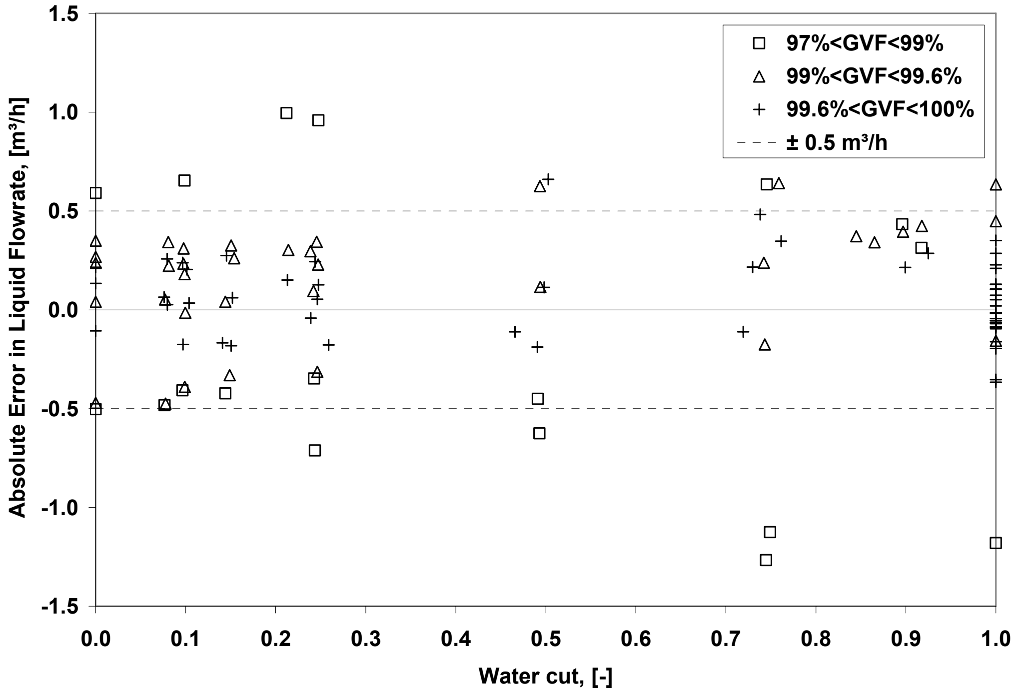

Figure 13 - Error in liquid flow rate prediction vs. water cut.

Figure 13 shows the effect of water cut on the measured liquid flow rate demonstrating that there is no discernable effect of liquid viscosity and to a certain degree density.

MULTIPHASE TESTS

The Sonar-Venturi is primarily designed for wet-gas flow; however, it was also tested at NEL to evaluate the performance in off-design conditions. An extension of the wet-gas iterative solution described above was devised for resolving the liquid and gas flow rates under multiphase flow conditions. While analogous *ORS* and *ORV* concepts are used in characterizing the multiphase response of the single phase devices, the definitions of these quantities as well as their correlating parameters are different from the ones used for wet gas. The ORV in multiphase flows follows published methods and is analogous to variations in discharge coefficient in multiphase flow conditions.[8,9] The Sonar over-reading was characterized in a form similar to the wet-gas methodology. No refinement was attempted for this first evaluation of multiphase performance and no effort was made to asymptotically match the multiphase and wet-gas models.

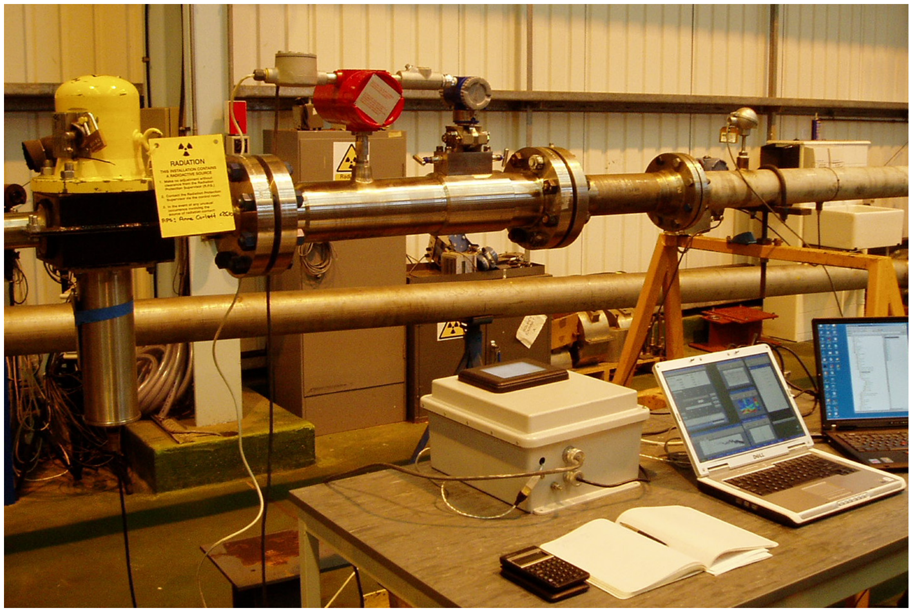

Figure 13 - Sonar-Venturi flowmeter at NEL multiphase test facility. The gamma densitometer in picture is for R&D only and has not been used in the Sonar-Venturi flowmeter calculations.

The results were categorized using three gas volume fraction (GVF) ranges namely *0<GVF<60%*, *60<GVF<80%*, and *80<GVF<97.5%*. It is worth emphasizing that even the highest GVF in this facility does not constitute wet-gas flows and that intermittent flow conditions occurs at all GVF above 30%.

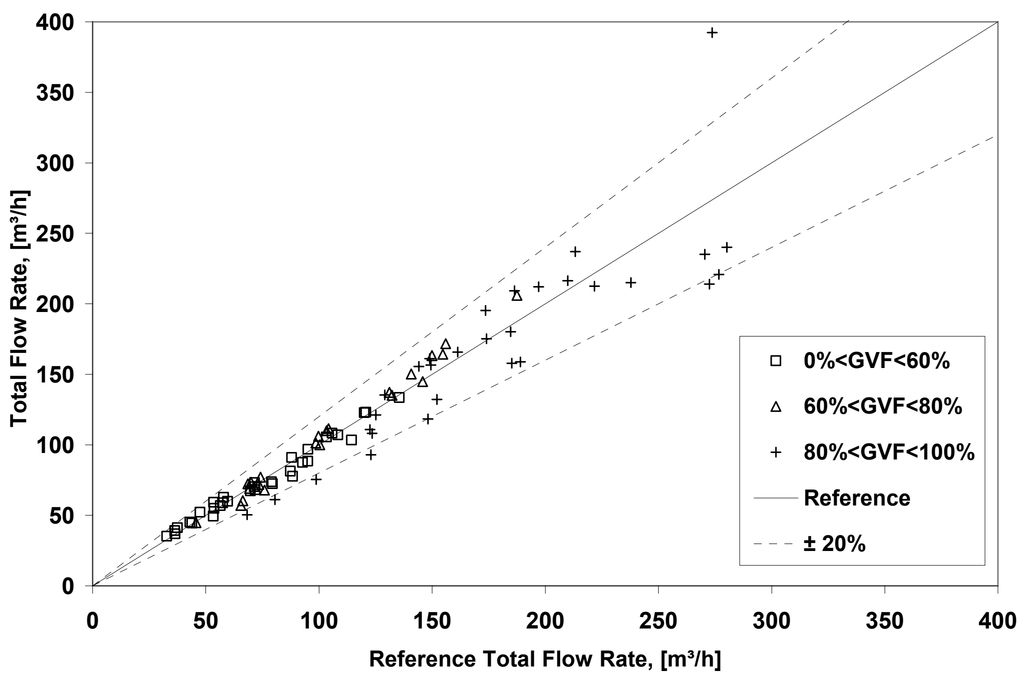

Figure 14 - Total flow rate in multiphase

Figure 14 shows the total flow rate for all GVFs ranging from 0 to 100% and all water cuts ranging from 5 to 75%. It can be seen that the total flow rate is predicted to within ±20% for *GVF<80%*, however, at higher GVF the measurement is erratic. The velocity reported by Sonar at these conditions is not deemed representative as a time-averaged total flow rate. Further refinement of Sonar processing is required to resolve these flow conditions accurately.

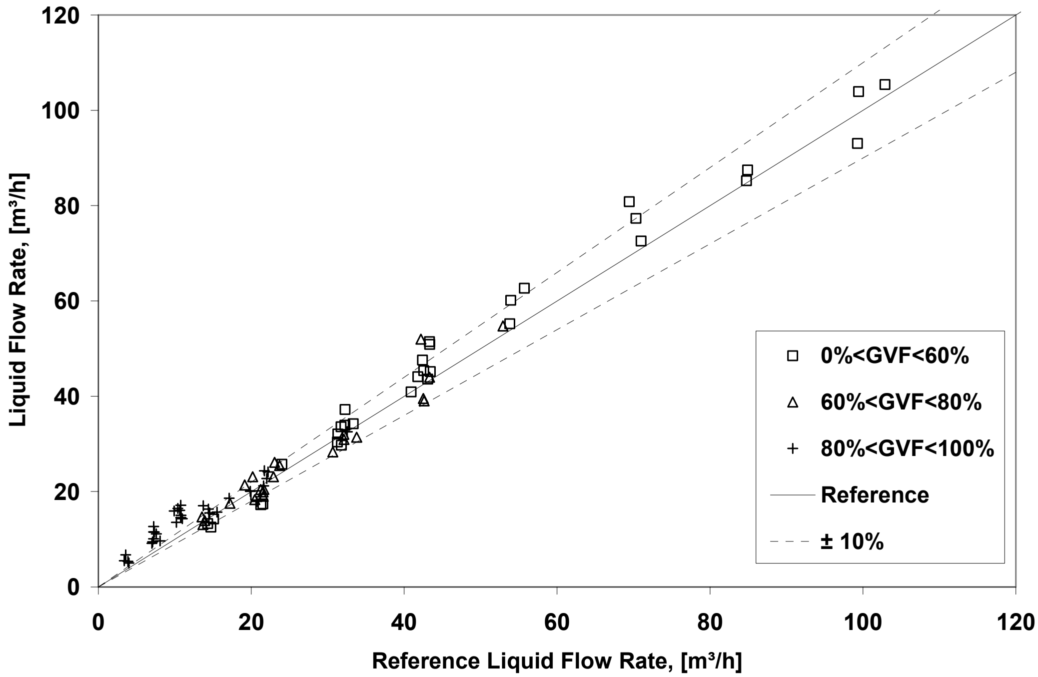

Figure 15 - Liquid flow rate in multiphase.

Similar to the total flow rate, Fig. 15 shows that liquid flow rate is measured to within 20% for GVF<80%. The effect of the inaccurate Sonar velocity between 80 and 97.5% GVF exacerbates the liquid error.

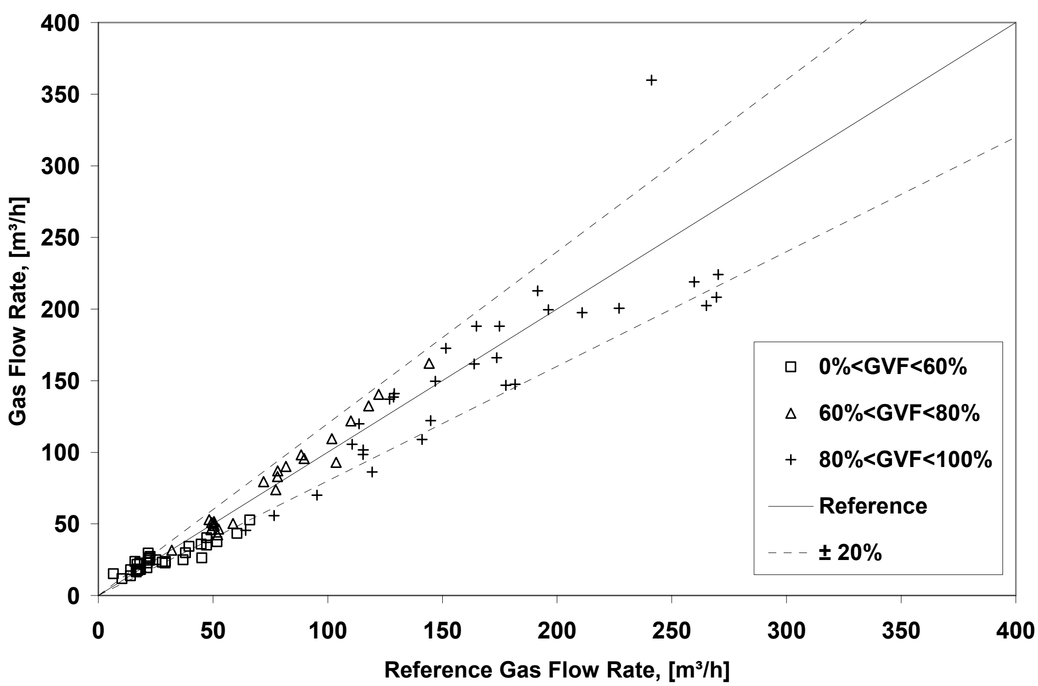

Figure 16 - Gas flow rate in multiphase.

Figure 16 shows the gas flow rate. The gas rate is predicted to within 20% between 60 and 80% GVF, but larger errors are prevalent at lower GVF. Again, the measurement performance between 80 and 97.5% GVF is reduced due to low accuracy of the Sonar in this regime to the widely time-varying properties of the flow. Currently Sonar algorithms do not attempt to capture transient properties, but is rather reporting volumetric and time-averaged flow properties. It is worth noting that the Sonar processing algorithms can readily identify the slugs and offer potential to calculate both slug and bubble velocity and volume.

CONCLUSIONS

The Sonar-Venturi-(Red Eye) flowmeter constitutes a high-accuracy top-side evolution of the downhole fiber-optic flowmeter technology. The flowmeter combines Sonar sensors with an extended throat Venturi that enables measurement of liquid and gas rates in wet-gas and multiphase flows. Addition of a Red Eye 2G water cut meter enables distinction of oil/condensate and water. This flowmeter has been tested in a range of wet-gas and multiphase flow conditions at CEESI and NEL where it was found that for wet-gas flows the total and gas flow rates are measured to within ±5% and liquid rate is determined to be within ±20% in API Type II wet gas and ±0.5 m^3/hr in API Type I wet gas.

In multiphase flows, liquid and total rates are predicted to better than ±20% at GVF below 80%. In low pressure highly unsteady slugging flows, there is a reduction in Sonar measurement capability and hence the measurement performance is reduced. This was evident between 80 and 97.5% GVF in the multiphase facility. Additional work is required to improve the multiphase and especially Sonar performance in unsteady flow conditions. The Red Eye water cut meter has been demonstrated in other work to be within ±5% (absolute) over the full range of GVF and WLR and is not significantly affected by slugging flow conditions.

ACKNOWLEDGEMENTS

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NOMENCLATURE

Acronyms and Symbols

A	=	Area, [m^2]
API	=	American Petroleum Institute
CEESI	=	Colorado Engineering Experiment Station, Inc
f	=	Function
Fr	=	Densimetric Froude Number, [-]
GVF	=	Gas Volume Fraction, [-]
LMQ	=	Liquid Mass Quality
m	=	Mass flow rate, [kg/s]
NEL	=	National Engineering Laboratory
NIR	=	Near-Infrared
ORS	=	Over-Reading Sonar, [-]
ORV	=	Over-Reading Venturi, [-]
Q	=	Volumetric Flow Rate, [m^3/s], [m^3/hr]
V	=	Velocity, [m/s]
WLR	=	Water Liquid Ratio, [-]

X_{LM} = Lockhart-Martinelli parameter, [-]
ΔP = Differential Pressure, [bar]

Subscripts

g = Gas
l = Liquid
m = Mixture
s = Superficial
t = Total

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