Operational Experience with Multiphase Meters at Vigdis

By
Odd-Petter Kalsaas, Fluenta AS, and Espen Egner, Saga Petroleum ASA

Introduction

Two identical 8» MPFM 1900 VI were delivered to the Vigdis Field Dev. project in January 1996. The meters are installed on the Snorre platform, one on each of the main flow lines from the Vigdis satellites, and were commissioned for use in October 1997.

Based on an unexpected shift in the calibration of the capacitance sensor, observed and corrected during commissioning, Fluenta recommended to Saga Petroleum that the two meters should be upgraded from ceramic liners to the new PEEK open electrode construction. Saga agreed to this recommendation, and the job was performed during a two week planned shutdown in May 1998.

The two multiphase meters were re-commissioned in first week of June '98. Further adjustments were done during the next months, in order to optimise the performance of the meters. MPFM measurements during a multirate test from all Vigdis wells are compared to test separator measurements in April 1999.

Comparison between the multiphase meters, and the downstream separator measurements, now shows stabile and repeatable measurements well within Fluenta uncertainty specifications.

This paper will report on the combined experiences of Saga Petroleum and Fluenta, both with respect to failure mode, repair, operational experience and the use of data.

2. The Fluenta MPFM 1900VI measurement technology

The Fluenta multiphase meters are specifically designed to handle the various, and often complex, flow regimes that must be expected, without introducing mixing or separation of the flow. This has been achieved by developing a unique method for interpretation of sensor signals, the Dual Velocity method. This method is capable of handling complex flow regimes, including severe slugging, inhomogeneous phase distribution and interphasial slip.

2.1. Measurement principle

The MPFM 1900VI measurement system consists of a capacitance sensor, an inductive sensor, a gamma densitometer, a venturimeter and a system computer. The mean dielectric constant of the flow is measured using a non-intrusive, surface plate, capacitance sensor. The mean density of the flow is measured using a clamp-on gamma densitometer. Together these two measurements provide the instantaneous composition of the flow at the measurement location. At high water cut, when water is the continuous liquid phase, the mixture conductivity is measured using an inductive type sensor. This then replaces the capacitance measurement in the composition calculation. Velocity of the flow is determined by cross-correlation between different electrode pairs in the capacitance sensor. A venturi meter extends the range of the multiphase meter to cover single phase liquid and annular flow, and add redundancy to the velocity measurement. By combining both the compositional and the velocity information of the flow, the actual flowrates of oil, gas and water are determined by mathematical models hosted in a PC system.

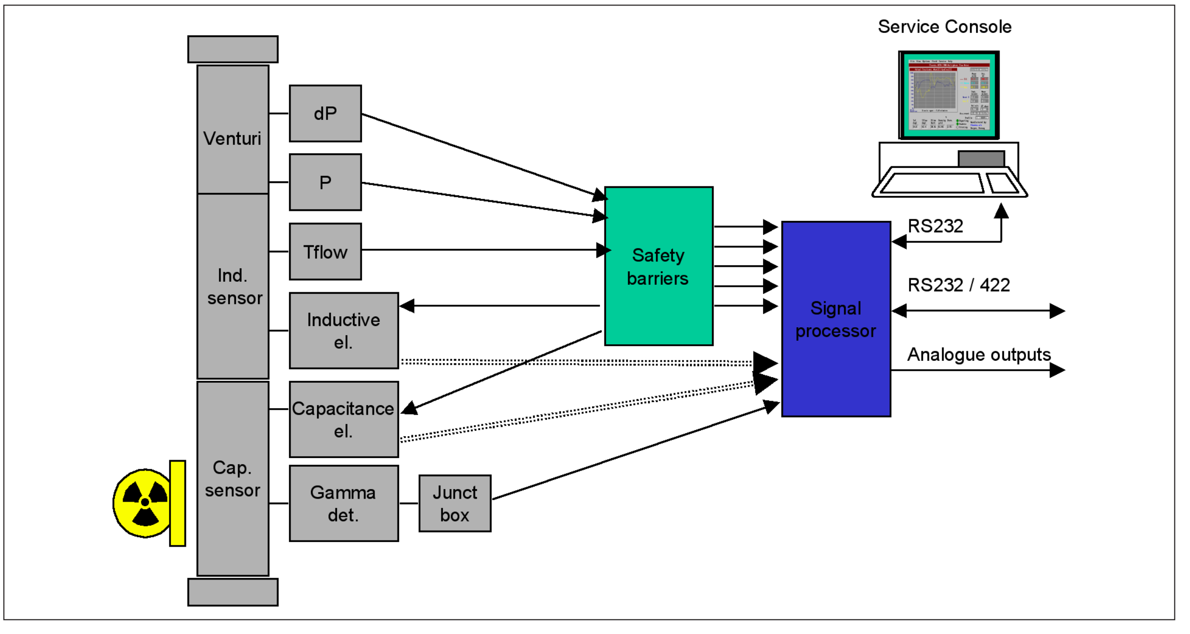

Figure 2.1 The Fluenta MPFM 1900VI; Block diagram

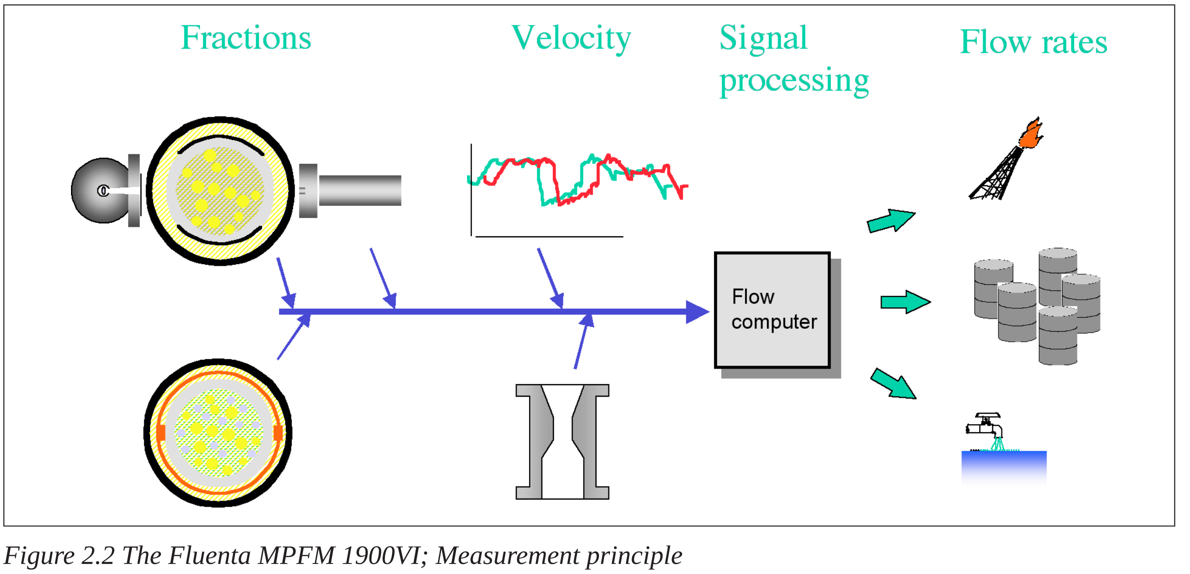

Figure 2.2 The Fluenta MPFM 1900VI; Measurement principle

2.2. The Dual Velocity method for handling of interphasial slip.

The sensor system has been configured to measure the distribution of velocities present in the flow, and interphasial slip is directly measured and compensated for using the unique “Dual Velocity method”. This is achieved by measuring the two most predominant velocities in the multiphase velocity distribution; the velocity of the pseudo-homogenous dispersed phase, and the average velocity of larger gas bubbles.

By combining these velocities with measured cross-sectional area fractions of dispersed phase and “large bubbles”, flowrates of oil, gas and water can be calculated
irrespective of flow regime (restricted to vertical upwards flow). In a somewhat simplified way, one can explain the Dual Velocity method to treat the flow as a “two-phase” mixture in terms of velocity: a pseudo-homogeneous mixture of oil, water and small gas bubbles; and a “free” phase consisting of larger gas bubbles travelling with an average velocity significantly higher than that of the “dispersed phase”.

The non-intrusive design, together with the Dual Velocity method for handling of phase slip, means the Fluenta multiphase meters do not require mixers to homogenise the flow, or separator to split the flow, before measurement. This gives the meter a wide operating range, which is not limited by the efficiency of the upstream flow conditioner or splitter. Interaction with the flow is kept to a minimum, avoiding pressure drop, erosion, or creation of emulsions that may otherwise seriously affect the downstream process.

2.3. Operational experience

Fluenta has participated with good results in a number of independent tests, both in lab oratory as well as in field, with its multiphase meters. Perhaps even more important is the extensive operational experience that has been accumulated since introduction of the multiphase fraction meter MPFM 900 in 1992. A total of 20 Fluenta multiphase meters are now in operation world wide. Reporting of test results and operational experiences from these various installations is not scope of this presentation, the reader is however referred to separate documentation, see reference list at the end of this paper.

As a brief summary, however, the referred tests and field installations conclude that the Fluenta multiphase meter provides data of a quality at least as good as a well managed test separator, that the availability of instantaneous data provides for improved well control, that the meter is easily maintained and operated, and that the failure rate is low.

Operational experience has however also shown that the liner technology previously used in the capacitance sensor has been a week part of the system. The problem that has occurred in some applications has been related to stability and surface wetting of the ceramic liner. A new sensor construction, avoiding the previous liner technology, was introduced in 1997. This has been a success. The new capacitance sensor construction employs open electrodes embedded in PEEK (Polyetereterketone). The open electrode design increases sensitivity of the capacitance measurement, as the ceramic liner previously separating the electrodes from the bulk medium has been removed. But more important; the previous problem of water wetting of the liner surface is avoided. Not only is the liner removed, the PEEK insulator backing is also inherently hydrophobic. The first unit with the new sensor construction went into operation in August 1997. These installations have confirmed the expected good stability and sensitivity of the new design.

3. Field installation at Vigdis

Two identical 8» MPFM 1900 VI were delivered to the Vigdis Field Dev. Project in January 1996. The meters are installed on the Snorre platform, one on each of the main flow lines from the Vigdis satellite.

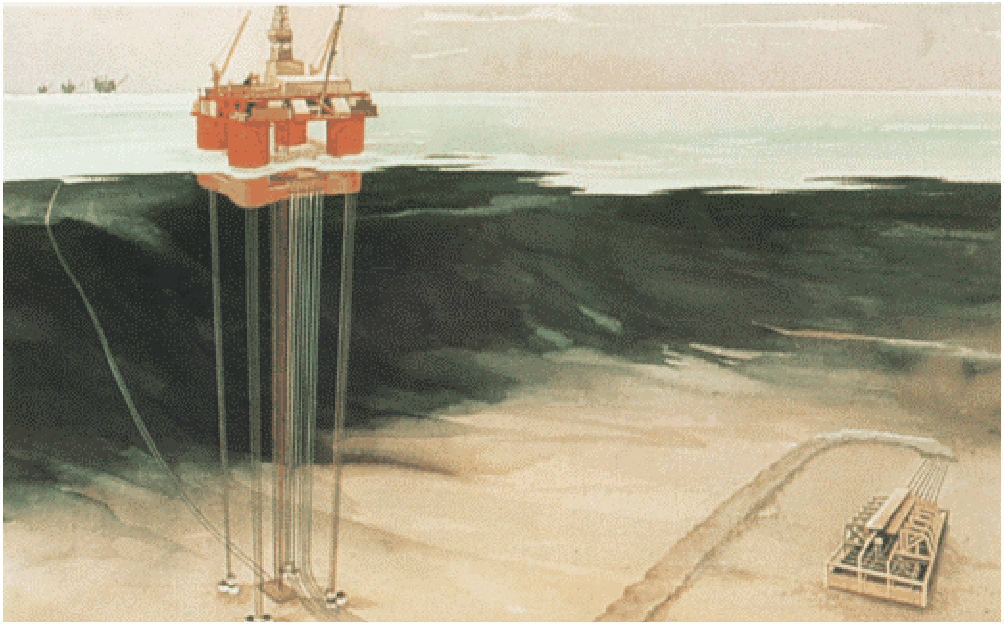

Figure 3.1 Snorre TLP

Reservoir oil is transported 6-7 km through two separate production lines from the Vigdis field to Snorre TLP, where the Vigdis process facilities are sited. The arrival temperature at Snorre TLP during normal production is 70°C. Normally three to four wells are produced through each of the production lines. A schematic drawing of the main Vigdis topside process is shown in Figure 3.2. The two 8'' MPFM are marked with circles in the figure. All MPFM measurements are recalculated to standard conditions using PVT properties representing an approach to the Vigdis process.

3.1. Purpose of Fluenta 8'' MPFM at Vigdis

Testing of individual wells at Vigdis are performed using the test separator at Snorre TLP. One line may be lead to the test separator, while the other line is producing through the Vigdis process. With an increasing amount of wells producing to Snorre TLP, there is a need for alternatives to the traditional test separator control of individual wells. Fluenta 8'' MPFM 1900 provide continuous measurements of each of the two production lines, so that observed variations in the Vigdis production may be tracked to the deviating line. Regardless of other activities at the Snorre TLP test separator, all wells at the deviating line may be tested individually, using the Fluenta 8'' MPFM 1900. In addition, Idun measurement system is installed in each of the wells for allocation purposes. Fluenta 8'' MPFM 1900 measurements on each of the production lines, were intended to be used as a continuous quality control and a quality improver for Idun.

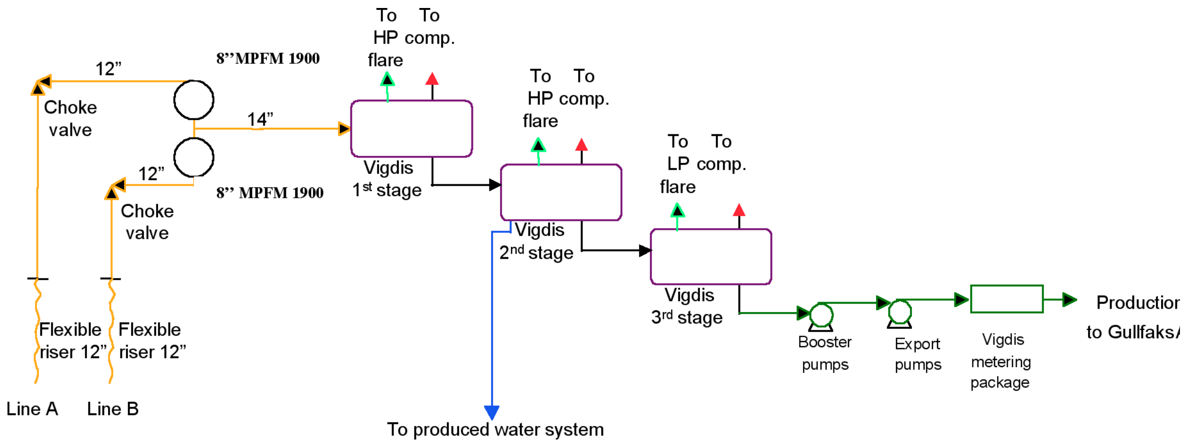

Figure 3.2 A schematic drawing of the main Vigdis topside process, including the placement of Fluenta 8" MPFM 1900.

3.2. Reference measurements

Reference measurements for each of the multiphase meters are achieved using the Snorre TLP test separator. There will be almost similar conditions at the 8'' MPFM and the test separator during a separator test of Vigdis, and good reference measurements are expected. Results from a multirate test are presented in this paper.

Fiscal oil measurements at the Vigdis metering package before transportation to Gullfaks A, are used as continuos reference oil measurements to the sum of both MPFM. There is no gas injection at Vigdis, and the field contains highly undersaturated oil with a constant GOR. The fiscal oil measurements may therefore be used as reference measurements of gas. Water produced from 2nd stage separator plus the remaining water in oil at Gullfaks A are used as reference measurements for water. This is not a fiscal reference.

4. Operational experience of multiphase meters

The two multiphase meters were installed in the Vigdis modules during the first half of 1996, while the modules were still at the assembly site at Nymo. First oil was flowed through the meters in the early part of 1997, and commissioning by Fluenta was performed during 22 – 28 October 1997.

During commissioning, Fluenta noted that the flow rate through multiphase meter tagged #801 was well below the lower operating range for the meter. The flow rate through the meter tagged #806 was within the operating range, and the flow rate measurements were in agreement with separator measurements. It was further noted that the calibration of the capacitance sensor had shifted since the factory calibration. This was commented as unusual. No accurate comparison between multiphase meter readings and separator measurements were performed or available. Better PVT data for calculation to standard conditions would be required in order to deliver optimum performance from the meters.

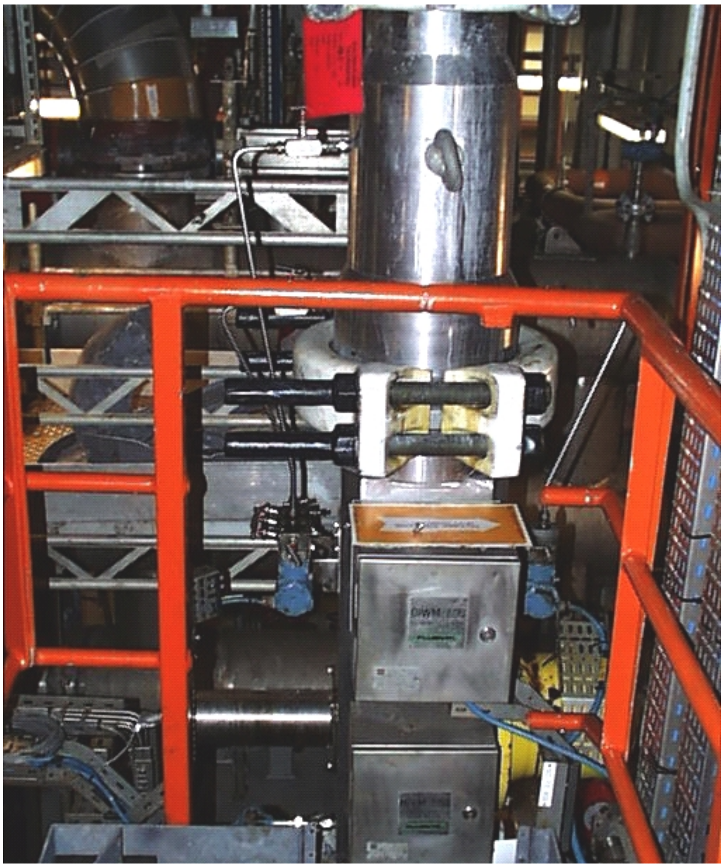

Figure 4.1
One of the two multiphase meters installed at the Snorre TLP

4.1. Operational experience; October ’97 – April ‘98
Both meters have been operational the whole of this period. No operational problems have been reported, and no scheduled or unscheduled service has been performed. Data for direct calibration or comparison between multiphase meter readings and separator readings has not been available.

4.2. Refurbishment of the internal sensor assembly
Based on the observed and unexpected shift in the calibration of the capacitance sensor, Fluenta recommended to Saga Petroleum that the two meters should be refurbished. Saga agreed to this recommendation, and the job was performed during a two week planned shutdown in May 1998.

The work involved a complete upgrade of the sensor internals, replacing the previous liner technology with contact electrodes in a Peek insulator. The meters were back in the line within the scheduled shutdown period.

4.3. Operational experience with the new sensor design
The two multiphase meters were re-commissioned in first week of June ‘98. The measurements from meter #806 were in line with the separator readings, but no data for accurate comparison or calibration were available. It was observed that meter #801 was still operated well below the operating range of the meter.

In August 1998, Saga reported to Fluenta that water cut readings for meter #806 was inerror. This had occurred as an additional well had been routed through the meter, and a flow rate dependence of the water cut was observed. Investigation of the problem showed that the open electrodes tended to pick up electrostatic noise generated within the flow itself (due to friction). In the previous sensor design this electrostatic noise was filtered by the capacitance of the liner. The solution was therefore to implement a similar filter function in the detector electronics. The sensor detector electronics was modified according to the above, and the flow rate dependence of the water cut disappeared.

Since then, no further operational problems have been observed and both meters have been in continuous operation with satisfying performance. Figure 4.2 shows the oil flow rates from the meters compared to the fiscal measurements in the beginning of February 1999. The readings from the meters were about 8% too low at the time.

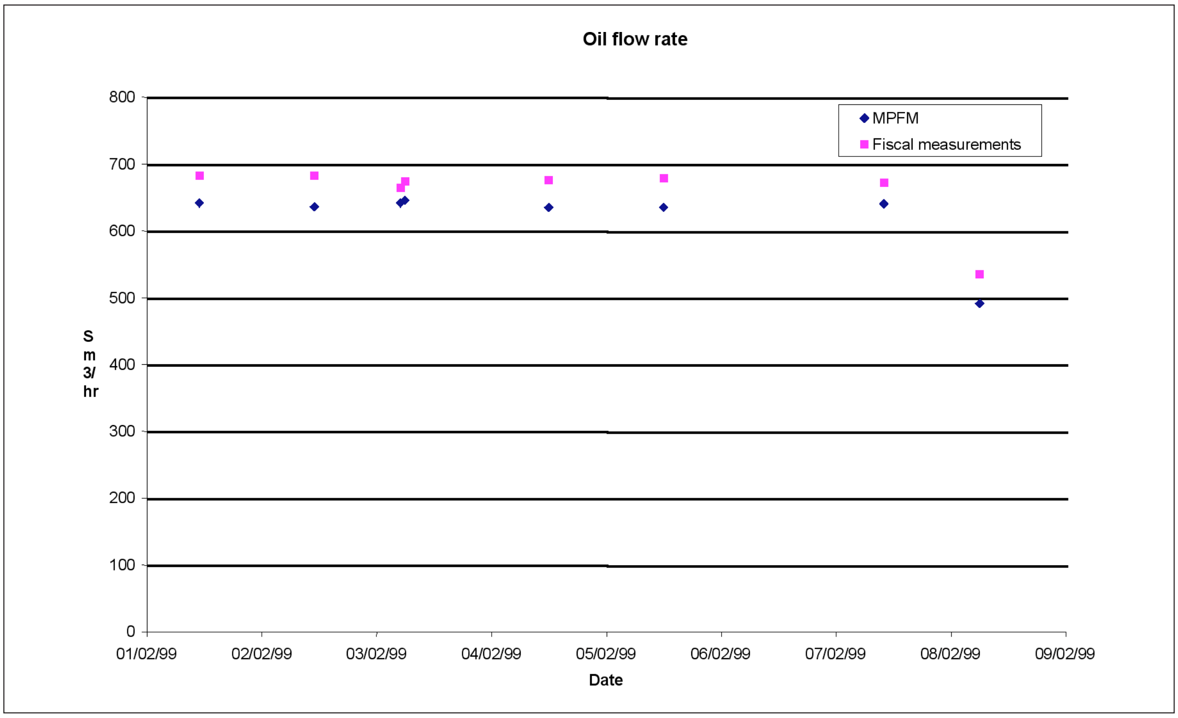

Figure 4.2 Oil flow rate from multiphase meters compared to fiscal measurements, February 1999

4.4. A preliminary conclusion

The upgrade from the originally delivered sensor construction (ceramic liners), to the new open electrode design have proved successful. Measurements from the two meters show repeatable readings, in good agreement with process measurements and fiscal readings at the Snorre platform. The sum of the measured oil flow rate from the two multiphase meters do however show a systematic deviation of around –8% from the fiscal oil measurement. This is within Fluenta specification for a statically calibrated meter. By in-situ flow calibration, the systematic deviation can be further reduced.

At this stage, one could therefore have decided to implement a simple solution using meter factors to correct the deviation. The two Vigdis multiphase meters are normally operated within a fairly narrow operating range, which would have made this solution quite acceptable.

5. In-situ performance optimisation and evaluation

Saga wanted the meters to be capable of handling a large change of working point, e.g. variations that will occur when different well combinations are routed through the meters. In the beginning of 1999, Saga and Fluenta therefore started discussing how to narrow the gap between multiphase and fiscal measurement of oil, without using the simple approach of factor calibration. Although this approach would certainly have improved the results for this particular well combination, a larger change of working point would possibly require re-calibration.

The signal processing used in the Fluenta multiphase meters are based on a physical interpretation of the flow conditions inside the meter. Any change of these interpretation models should be generic, rather than specific for a particular installation. In order to avoid the simple factor calibration, the actual reason for the deviation would therefore have to be identified.

5.1. Density model improvements

Data from the multiphase meters were analysed, and it was found that the assumed density distribution within the dispersed part of the flow was too simple. While the implemented model assumed a homogeneous density distribution in the dispersed flow in between large gas bubbles, a more correct approach is to assume a higher concentration of gas towards the middle of the pipe also in the dispersed part of the flow. The meters at Vigdis are quite large (8” ID), which explains why the effect of a simple model for the density distribution is more pronounced here than for other installations.

A new improved algorithm was developed, assuming a higher density closer to the wall of the pipe than in the centre of it. This results in a lower gas fraction and hence a lower gas flow rate, in addition to a lower water cut. The measured oil flow rate will then increase. This new model is implemented as a general improvement of the flow models used in all Fluenta multiphase meters.

In March 1999 the new density distribution algorithm for the dispersed phase of the flow was implemented. Since no test separator was available at the time, the sum of the flow rates through the two meters were compared to the readings from the separators at stage 1, 2 and 3, and the fiscal oil flow rate measurements. The readings were stabile and repeatable, within the uncertainty specifications for the meters. The water cut and the flow rate through the two meters are not same, so this test was a check of the sum of the flow rates and the average water cut calculated by the two meters. Error! Reference source not found. shows the flow rate through the meters compared to fiscal measurements in the beginning of April 1999. The readings from the meters are about 3% low. Compared to Figure 4.2 the deviation was reduced by 5% by using this improved algorithm.

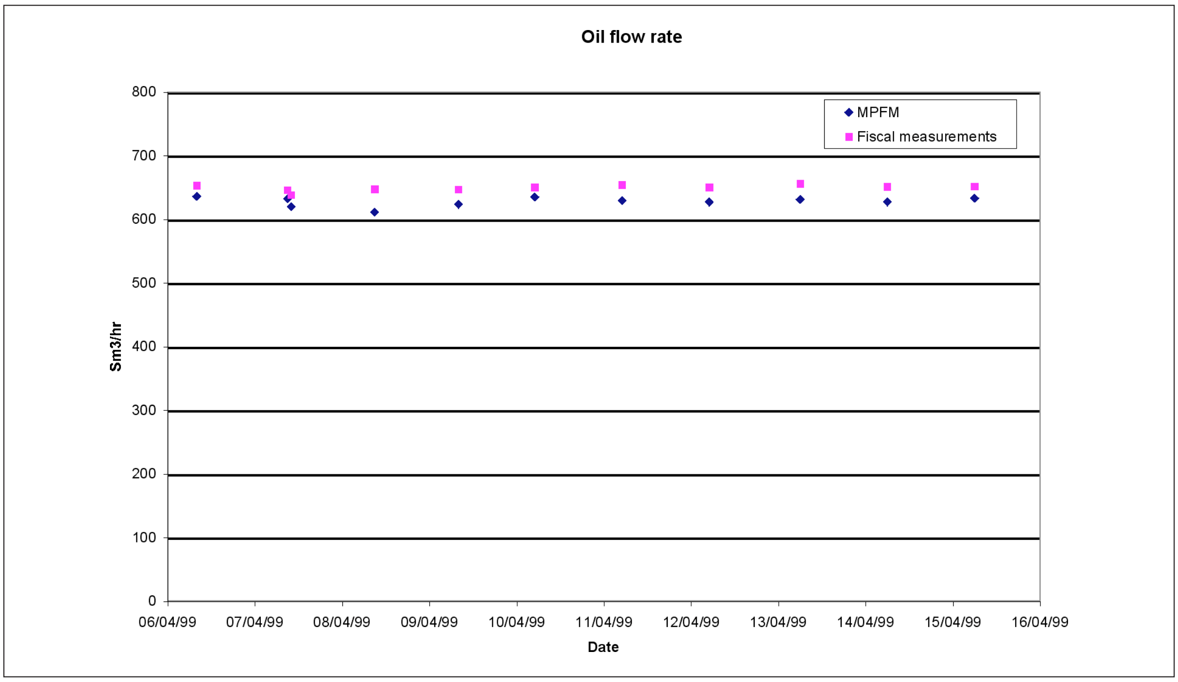

Figure 5.1 Oil flow rate from multiphase meters compared to fiscal measurements, April 1999

5.2. Multi rate test

In April 1999 a multi rate test of the Vigdis production wells was performed. Flow from different well combinations was sent through one of the multiphase meters at a time, to a test separator. This made it possible to test each meter with different flow rates and water cuts.

Figure 5.2. shows the liquid flow rate measured with meter #801. Except for the lowest flow rate, all points are within the +/- 7% uncertainty specification. The lowest flow rate has a deviation of 9%. At this point the meter is operating well below its specified operating range.

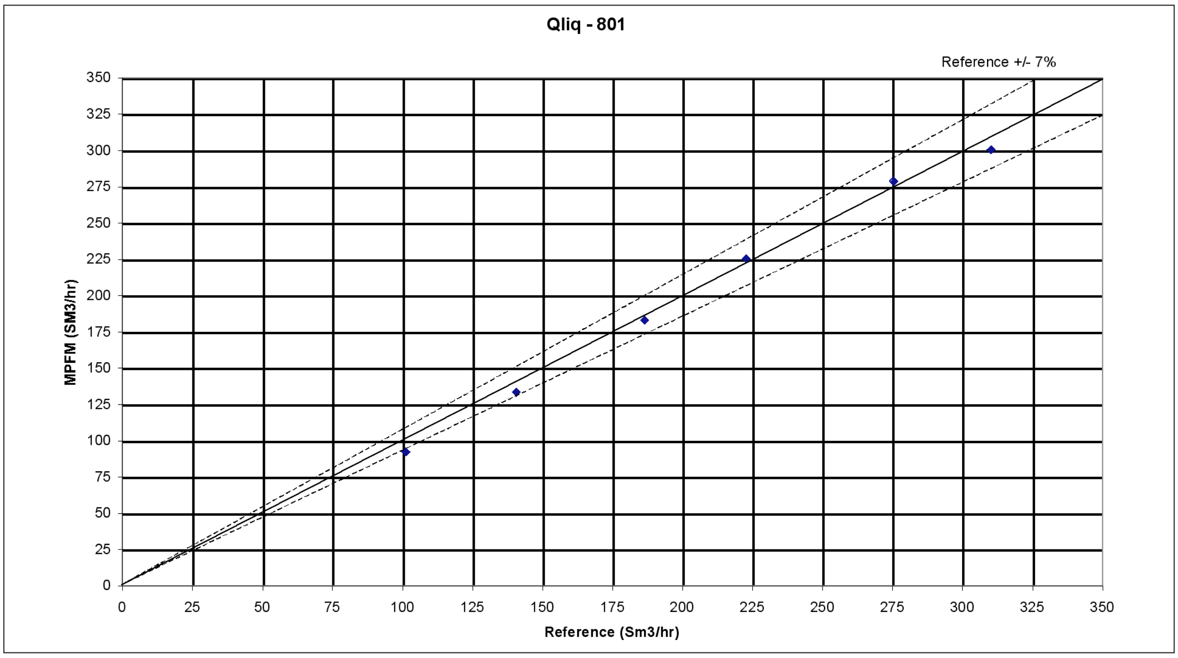

Figure 5.2 Liquid flow rate from meter #801. Water cuts were from 0% to 17% for these points. The water cut readings from the meter were from 0% to 6% (abs) too high.

The gas flow rate from meter #801 is shown in Error! Reference source not found.. All points are within the +/- 10% uncertainty specification. The lowest flow rate has the highest deviation. As with the liquid flow rate, the meter is here operating well below its specified operating range.

The offset in water cut reading is caused by non-calibrated capacitance electronics. The electronics were upgraded in flowing conditions, and the process schematic at Snorre will not allow static system calibration without shutting down the flow. Static calibration will be performed at first opportunity.

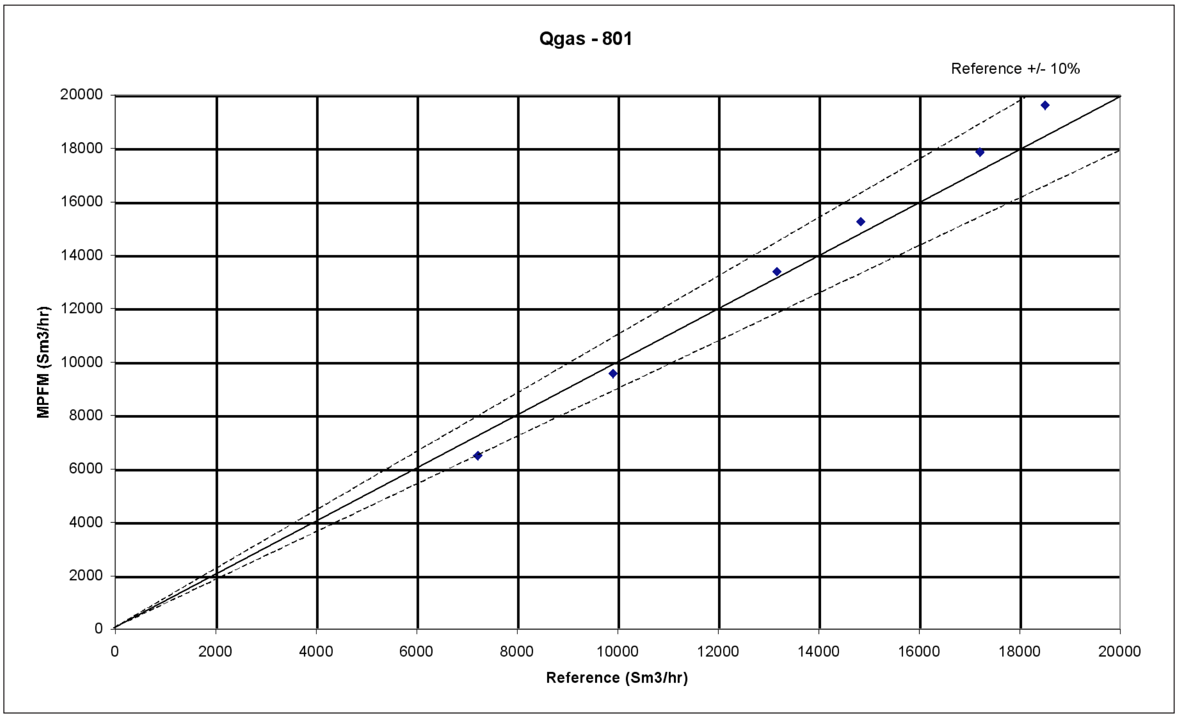

Figure 5.3 Gas flow rate from meter #801.

Figure 5.4 shows the liquid flow rate measured with meter #806. The curve shows that the deviation increases when the flow rate and the measured differential pressure drop. The reason for this is probably an offset in the dP transmitter. It was working in the lower 0.2% to 4% range for half of the testpoints.

Figure 5.5 shows the gas flow rate measured with meter #806. The curve shows that the deviation increases when the flow rate and the measured differential pressure drop, as happened with the liquid flow rate. The dP transmitter was working in the lower 0.2% to 4% range for half of the testpoints, as indicated on the figure.

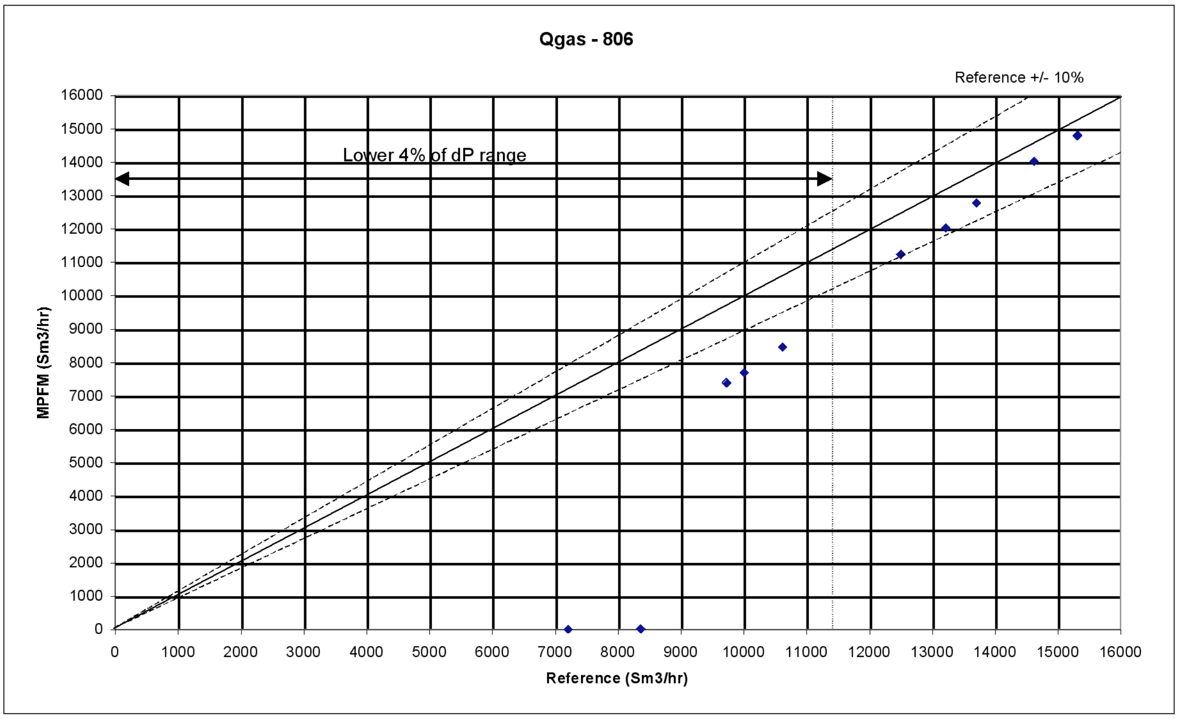

Figure 5.5 Gasflow rate from meter #806

5.3. dP model improvements

After the multirate test was finished, the results were analysed. It was observed that the dP transmitters over the venturi on the two meters gave different readings when the measured dP was in the lower 0.2% to 4% of the dP range. For these low rates the gas and liquid flow rate readings for meter #806 were too low. At higher flow rates a minor dP difference can be neglected, since the flow rate through the venturi is given by the square root of the dP value. Similar experience from other installations had already led to a new algorithm which calculates a dP offset based on the instantaneous mixture density. This offset correction is necessary since the venturi is vertically mounted, which causes the weight of the flow mixture inside the sensor to give a static contribution to the dP reading.

The distance between the two pressure outlets is a function of the meter ID, but is normally between 15 and 30 cm. When the differential pressure caused by the flow is in the lower 5% of the range of the cell, an offset of this size will give a significant contribution to the dP reading. This effect will increase with the distance between the pressure tappings, and will therefore increase proportionally with meter ID.

The new algorithm was implemented in meter #806 in August 1999. Different flow rates have been tested and the results are good. The dP readings from meter #801 are slightly higher than meter #806. It seems that the dP transmitter on meter #801 has a small offset which corresponds to the weight of the flow mixture inside the meter. Therefore the program in meter #801 will not be upgraded before more results are available from meter #806. Error! Reference source not found. shows the flow rate through the meters compared to fiscal measurements after the new dP offset algorithm was implemented. The deviations between the readings are within +/- 3%.

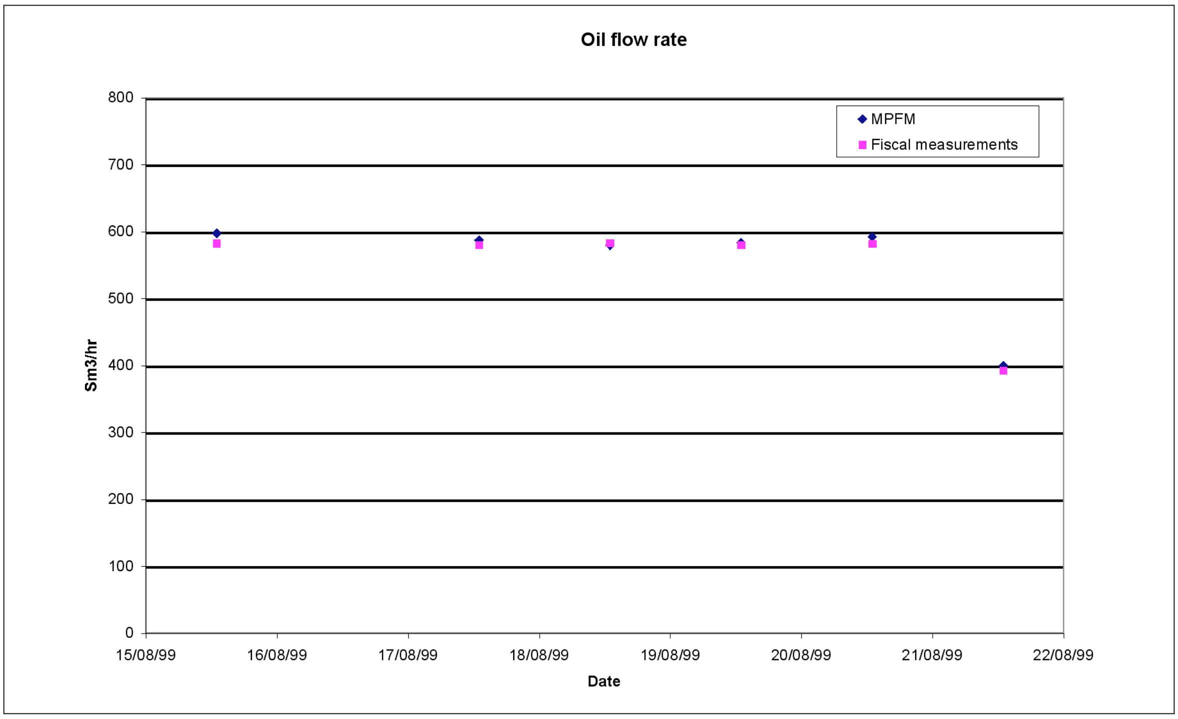

Figure 4.2 Oil flow rate from multiphase meters compared to fiscal measurements, August 1999

6. Summary and conclusion

Two Fluenta 8” MPFM 1900 VI multiphase meters are installed at the Snorre TLP, one in each of the production lines from Vigdis. There is no bypass facility installed, and in normal operation, there is also no possibility to individually check the meters towards a reference. This configuration does not easily accommodate performance monitoring, system modifications or calibration. Saga Petroleum and Fluenta have worked closely together to overcome this, and have arrived at a high quality multiphase measurement system for the Vigdis satellite.

A potential problem with the sensor liner technology was identified during commissioning of the meters, but was rectified during a planned shutdown six months after commissioning, before any serious malfunctioning had been experienced. Both meters were then upgraded with new sensor internals, with open electrode design. The refurbishment of the two meters performed in May 1998 made the readings from the meters repeatable, without any drifting. A filter function implemented in the detector electronics removed a flow rate dependence of the water cut which was observed in August 1998.

After this upgrade, the combined meter readings gave an oil flow rate of about 8% low compared to fiscal measurements. Data from the meters were analysed, and indicated that further improvements were possible. Saga and Fluenta agreed not to use meter factors in order to correct the observed deviation, but instead try to improve the signal interpretation models used in the meters. The first change was made to the density distribution model for the dispersed phase of the flow. The new algorithm reduced the deviation between the meters and the fiscal measurements from about 8% to 3%.

The multirate tests performed in April 1999 showed that most points were within the meter specification. In addition, it showed that the dP transmitters on the meters had different offset values. That gave too large flow rate deviations when the transmitters operated in the lower 0.2% to 4% range. A new dP offset algorithm was developed which compensates for the static contribution caused by the weight of the fluid between the dP tappings on the meter. This algorithm was implemented in August 1999. The oil flow rate deviations between the meters and the fiscal measurements have been within +/-3% since this upgrade.

Figure 6.1 gives an overview of the oil flow rate measurements since January 1999. It shows clearly how the deviations between meter readings and fiscal measurements have been reduced since the upgraded flow models were implemented.

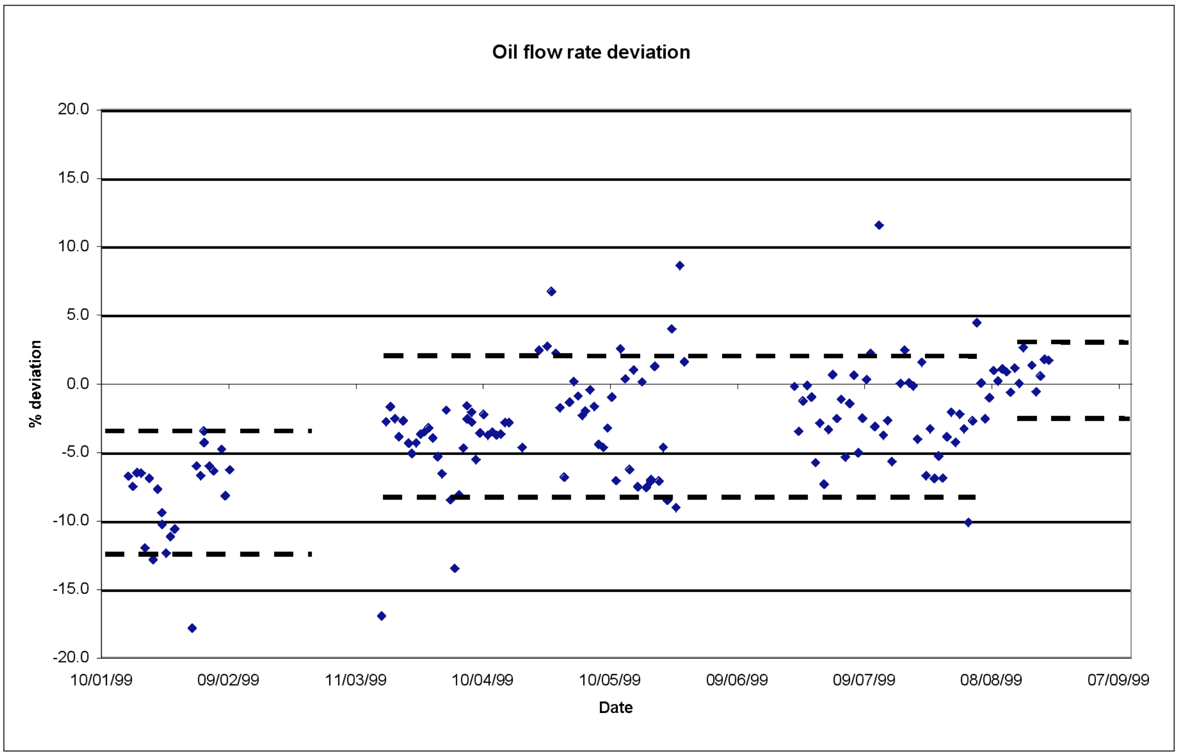

Figure 4.2 Deviation between oil flow rate readings from meters and fiscal measurements since January 1999

References;
Tests and Field applications of Fluenta Multiphase meters

1. NEL test report no. 187/95: NEL Multiflow Project – Characterisation of the performance of multiphase flowmeters for oil/water/gas measurement, January 1996

2. NEL test report no. 092/97: NEL Multiflow II Project – Characterisation of the performance of multiphase flowmeters – The challenge to acceptability, January 1998

3. NEL test report no. 111/97: Independent testing of Fluenta Multiphase Flowmeter for Seligi F, February 1998

4. Hydro Research Centre Porsgrunn test report no. 96S_CJ5: The "Porsgrunn 2" test programme of multiphase flow meters, November 1996

5. The North Sea Flow Measurement Workshop 1995: " The Norwegian test programme for qualification of multiphase meters", Ole Økland and H. Berentsen, Statoil; G. Flakstad, Saga Petroleum; S. A. Kjølberg and H. Moestue, Norsk Hydro

6. SPE 36837 Multiphase Flow Meter Successfully Measures Three-Phase Flow at Extremely High Gas Volume Fractions - Gulf of Suez, Egypt, *B Leggett et. Al*
7. OTC 8506: "MMS 1200 - Cooperation on a Subsea Multiphase Meter Application", *E.F. Caetano, J.A.S.F. Pinheiro, C.C. Moreira, PETROBRAS and L. Farestvedt, FLUENTA Inc*

8. OTC 8549: "The development and use of a subsea multiphase flowmeter on the South Scott Field", *S. G. Slater, A. McK. Paterson, M. F. Marshall, Amerada Hess (UK) Ltd.*
9. 4th Annual International Conference, "The future of multiphase metering"; "Multiphase metering in Malaysia - Current and the future", *Razali Ibrahim, Petronas Malaysia*

10. 4th Annual International Conference, "The future of multiphase metering"; "Multiphase metering developments in Brazil", *Dr. R. Machado, Dr. E. Caetano, J.A. Pinheiro, Petrobras Brazil*

11. 5th Annual International Conference, "Field applications and new technologies for multiphase metering"; "Multiphase metering qualification process at Petrobras – Field application stage", *Dr. R. Machado, Dr. E. Caetano, C. Kuchpil, C. B. Costa e Silva, M.J. Borges Filho, Petrobras R&D Center Brazil*

12. SPE 49118 Application of The First Multiphase Flow meter in The Gulf of Mexico, *Edward G. Stokes, Conoco Inc.; Dennis T. Perry, Petro Traces Inc.; Marschall H. Mitchell, Conoco Inc.; Martin Halvorsen, Fluenta a.s.*