CHAPTER 2

INTRODUCTION TO MULTIPHASE FLOW METERING

Following on from the review of multiphase flow fundamentals, this chapter introduces the basic concept of multiphase flow metering (MFM) and describes its applications for the oil and gas industry. The number, geographical distribution and future trends of MFM installations, are also presented.

2.1. What is MFM?

A broad definition of MFM is that of the measurement of the flow rates of each individual phase in a multiphase flow. According to this definition, a conventional two- or three-phase separator (followed by independent metering arrangements for each of the separated phases) can be regarded as a multiphase flow meter. However, when a multiphase flow is split into two or more single-phase flows (assuming that the separation is 100% efficient), the need to refer to multiphase flow ceases to exist. In fact, the wording ‘Multiphase Flow Metering’ started to appear well after the establishment of separators for industrial applications. MFM was first conceived for the non-intrusive metering of the simultaneous flow of two or more phases, without the need for separation.

Today, the term MFM is often used to include wet gas metering (i.e. the metering of a multiphase flow at high gas content) and the metering of heavy oils, both of which will be covered later on in this book.

The development of MFM was originally driven by instrument engineers and therefore, some definitions mirror the operational capabilities of specific metering devices, rather than capturing the actual nature of the flow being metered.

2.2. Brief History of MFM

The first commercial MFM’s appeared about 15 years ago, as a result of several multiphase metering research projects that took place in the early 1980s, focused on applications for the oil and gas industry. The driving
force to develop MFM technology was the forecast decline of production from the major North Sea fields, accompanied by the necessity to tie back future smaller discoveries to existing infrastructure. Increasing gas and water fractions, inherent in a mature producing province, would create more unstable flow conditions in existing production facilities and require more flexible multiphase solutions. Among the oil companies that gave their contribution to the development of MFM’s are BP, Texaco, Elf, Shell, Agip and Petrobras. The first tests of these prototype-MFM’s were carried out by BP and Texaco.

In less than two decades, MFM has become accepted in the field and is being considered among the primary metering solutions for new-field developments.

### 2.3. APPLICATIONS OF MFM TO THE OIL AND GAS INDUSTRY

The fluids produced from oil wells are rarely purely liquid or gaseous hydrocarbon mixtures. Most often, the fluid emerges as a multiphase mixture. In its simplest form, this is a mixture of natural gas and oil but, in many systems, water is present as are a variety of solid phases (sand, hydrates and asphaltenes). Traditionally, the flow rates of well fluids have been measured by separating the phases and measuring the outputs of the separated fluids by conventional single-phase techniques. However, the economics of offshore oil recovery have moved towards subsea completions with multiphase pipelines over long distances to either the shore or to existing platforms. The problems of MFM must therefore be faced.

Because of the great diversity of oil field conditions, multiphase flow meters are required to operate under a very wide range of conditions. Flow rates range typically from 1,000 to 35,000 barrels per day with gas/oil ratios in the range 100–12,000 standard cubic feet per barrel. The fraction of water in the oil ranges typically from 0 to 95% with pressures in the lines varying over a whole range with maximum values of the order of 10,000 psia; typical temperatures are 65–150°C. The line sizes also cover a very wide range; typical flowlines carrying the fluid from the well to a central collection point would be 2–8 in. in diameter, and typical production lines, which are used to transport the produced fluids, might be 8–36 in. in diameter. The fluid conditions can vary over the whole spectrum during the lifetime of operation of a given field.

Within the oil and gas industry, it is generally recognised that MFM could lead to greater benefits in terms of (Falcone et al., 2002): layout of production facilities, well testing, reservoir management, production allocation, production monitoring, subsea/downhole metering and costs.
2.3.1. Layout of production facilities
The use of MFM’s reduces the hardware needed for onshore, offshore topside and offshore subsea applications. Of primary importance is the removal of a dedicated test separator for well-testing applications. Using MFM (with its smaller ‘footprint’) for topside applications minimises platform space and load requirements for well-testing operations. Costly well-test lines can be stripped from the production facilities, which may be of vital importance for unmanned locations, deepwater developments and satellite fields.

2.3.2. Well testing
The conventional test separators are expensive and take a long time to monitor each well’s performance because of the stabilised flow conditions required (Figure 2.1). This becomes particularly serious for deepwater developments, due to the exceptional length of the flowlines. In such cases, the production of individual wells connected to the same manifold may be monitored via a dedicated test line to avoid shutting down all the wells and testing them one by one (with production deferral and possibly production loss). However, the expense of a separate flowline may be prohibitive,
hence the advantages of having a MFM installed in the subsea manifold. Test separators have an accuracy of between $\pm 5\%$ and 10\%, nowadays achievable via MFM’s too, but require regular intervention by trained personnel and cannot provide continuous well monitoring. A further disadvantage of conventional well testing with conventional separators is that wells suffer from shutdown cycles related to well testing. Hence, wells that are tested on a regular basis usually require more frequent workovers to maintain their production rates. Two MFM configurations that are possible for well-testing applications can be drawn. The first one is the integration of MFM in a conventional well-testing infrastructure (Figure 2.2). In this case, no reduction of overall footprint is achieved, but it is possible to continuously monitor a single well and test the others. The second configuration consists of a standalone MFM as well-testing device and involves an extremely simplified scheme without phase separation and remix (Figure 2.3).

Using MFM’s for exploration well testing provides satisfactory flow measurements without separation of the phases. It is claimed that they can even be used to monitor the well during its clean up flow (traditionally, this flow information is lost as the well stream is not directed through the test separator). Added value is represented by improved control of the drawdown applied to the formation, the pressure transient and shortened flow periods.
2.3.3. Reservoir management

MFM's provide real time, continuous production data so that Operators can better characterise field and reservoir performance by monitoring pressure decline, water influx, increasing gas–oil ratio and altered optimum conditions in artificial lift operations. Traditional test separators only provide information on cumulative volumes at discrete points in time. Figure 2.4 shows an extended application of MFM for reservoir management.

2.3.4. Production allocation

Any situation where production from different wells/fields owned by different Operators is commingled in the same pipeline for export to a common processing facility requires allocation metering (Figure 2.5). This could be the case of satellite developments tied back to subsea templates prior to processing on a host facility. Without MFM’s, the production from each well must flow through a test separator before commingling with the other produced streams. Accurate allocation of the fluids produced by a satellite development into a host facility is necessary to avoid litigations between the partners (Figure 2.6). For example, the host facility could claim that the satellite field is not delivering the agreed specifications in terms of maximum water content, solid content, impurities and gas production. On the other hand, the satellite project has to ensure that it
Figure 2.4  MFM for reservoir management and allocation.

Figure 2.5  MFM for production allocation: clustering and custody transfer.
cannot be accused of failing to meet the host-platform specifications when in fact it has not.

2.3.5. Production monitoring

The real-time monitoring of producing wells is recognised as the best way of optimising field performance. Monitoring a producing well implies the ability to track, in real time, any changes in fluid composition, flow rates or pressure and temperature profiles. MFM plays a key role in this scenario. Such information, combined with the critical analysis of historical data from the well itself or from analogue wells, allows diagnosis of the system and prediction of future trends. This allows production optimisation and extension of field life. Real-time production data from individual wells also allow to continuously update the drainage areas (and hence the reserves) associated to each well. This in turn helps the Operators plan workovers or infill drilling campaigns.

2.3.6. Subsea/downhole metering

Subsea/downhole MFM can be regarded as less challenging because of lower gas volume fraction (GVF), lower potential for hydrate, scale or
asphaltene formation, and higher density contrast between oil and water. Downhole MFM is best suited for ‘intelligent wells’, where streams from different producing intervals need monitoring. This would otherwise require running wireline interventions. Downhole MFM also allows continuous optimisation of artificial lift systems (e.g. electrical submersible pumps and gas lift) by detecting any well performance change.

2.3.7. Costs

When Operators have to decide between a traditional approach to the production facilities and one including MFM’s, they must compare the capital expenditure and operational costs of both solutions. In general, it is recognised that the capital outlay incurred with MFM is significantly lower than that of conventional metering hardware. The cost of MFM’s today is in the range of US$100,000–500,000, although the ultimate price of the unit will vary depending on whether it is for service onshore or offshore, will be located on topsides or subsea, the dimension of the tool and the number of units ordered. Due to the increased competition in the MFM market and the reluctance of both operators and vendors to release cost and performance data, it is difficult to track the evolution of MFM price history.

When comparing a traditional production layout (with test separator and test lines) with an installation with MFM, it appears that the latter option involves much lower capital expenditure. The installed cost of a separator can vary enormously, depending on the flow rates, pressures, temperatures, chemistry of the fluids to be treated, whether the separation takes place onshore, offshore or subsea, but is typically in the range US$1–5 million. It may also require several instruments, depending on its complexity. The test lines may be omitted in some MFM installations, which is useful as carbon steel flowlines of 4–6 in. in diameter cost approximately US$1.3–3.6 million per kilometre of pipe installed. It was estimated that, for a subsea development located 10 km from the host platform, using a subsea MFM could represent a 62% cost reduction through the elimination of test lines. In addition to this cost saving, MFM could improve the management of the production system with a 6–9% gain in the value of the oil recovered (Douglas-Westwood Limited, 2004).

The operational costs associated with test separators can be around US$350,000 per year for offshore installations. It was estimated that the operational expenditure for a MFM was likely to be 25% of the cost of the meter itself for the first year, then US$10–40,000 per year for both onshore and topsides applications (Sheers and Noordhuis, 1999). Today, with the increased reliability of the MFM hardware and more structured training of personnel, operational expenditure is spread more evenly over the operating life of a MFM, but it is hard to say whether operational expenditure has increased, decreased or remained the same.
2.3.7.1. Fiscal metering or custody transfer
There exist metering applications for which financial consequences are associated with the results of the measurement. Typically these are classified as either custody transfer (sales) metering or allocation metering (API, 2005). Unfortunately, the current MFM’s are not (and may never be) accurate enough to satisfy the custody transfer metering requirements, although such an application would guarantee the future of MFM’s.

2.3.7.2. Reserves estimation
When using reservoir modelling techniques to forecast oil and gas production, from which the ultimate field recovery can be predicted, the volumes and flow rates of fluids produced from a reservoir are used to tune the models. However, the metering of the produced fluids is not error free; the measurements may be taken with different levels of accuracy, depending on whether they are required for fiscal, allocation or reservoir management purposes. In the latter case, an accuracy of $\pm 10\%$ for the measurement of the produced hydrocarbons is generally considered to be acceptable. The metering uncertainty is particularly important for small discoveries or marginal fields, where the effect of wrongly predicting the ultimate reserves and recovery factor (RF) can severely impact the overall field economics. Since the results from production measurements are implemented in the reservoir modelling or production optimisation processes, it is clear that the accuracy of such measurements will affect the prediction of ultimate recovery from a reservoir. More accurate measurements imply that this uncertainty can be reduced. It is also clear that different levels of uncertainty may be acceptable, depending on overall field reserves, oil price, production lifetime, etc.

2.4. MFM Trends

It is difficult to establish the official number of MFM installations worldwide, as it is necessary to distinguish between:

- MFM’s installed and currently working;
- MFM’s installed, but now discontinued;
- MFM’s ordered, but not yet delivered;
- MFM’s delivered, but not yet installed and
- MFM’s used as portable well-testing solutions.

This type of information is commercially sensitive due to the high competition in the market of commercial MFM’s.

Following a recent market research by the authors (Falcone et al., 2005), it appears that a total figure for MFM installations to date, as defined in the bulleted list above, is in excess of 1600 units. Of these, 10% is represented
by mobile well-testing applications and a further 20% corresponds to wet gas metering. Western Europe, Asia-Pacific and the United States together represent 75% of the total number of MFM installations. Asia-Pacific has seen a sharp increase in MFM applications and has now overtaken the North Sea, where most of the initial installations of MFM’s began. However, the figure of 1600 units does not account for all of the installations since the early 1990s as some manufacturers have disappeared and some of the solutions have been discontinued. The recent years have seen mergers amongst manufacturers, but the entry of newcomers has kept the total number of commercial manufacturers at around 20. In some ways, these mergers have helped in the disclosure of information to the public domain, but knowledge has also been lost. Some of the smaller manufacturers, who were around a few years ago, have experienced mixed fortunes, becoming established ‘names’ and setting trends with the larger providers, while others have not really ‘cracked’ the market.

### 2.5. What Do We Expect From MFM?

Before discussing the capabilities of MFM, it is important to be clear as to what we expect MFM to be able to do for oil and gas developments. In other words, we need to go back to the reasons why MFM was originally conceived and then assess whether the initial objectives have been achieved.

Below is a wish list for MFM. The items in the list are not necessarily ordered by first priority, because these changes are dependent on the specific application.

- Repeatability and accuracy of the measurement.
- Applicability to a wide range of flow rates, phase fractions, fluids properties and operating pressure and temperature conditions.
- Ease of installation and intervention.
- Low-capital expenditure and operational costs.
- High mean time before failure (MTBF).
- Official acceptance by the governments.

Starting from the above wish list, Chapter 4 will review the current status and limitations of MFM technology.

### 2.6. Key Factors for the Selection of MFM Solutions

When selecting a MFM, Operators should give particular consideration to the below-mentioned key factors.
2.6.1. Confidence in a particular technique

How much confidence an Operator will place in a particular technique will be based on in-house expertise, experience in the field and liaisons with MFM specialists or Academia. As a universal MFM capable of handling the entire range of flow parameters and flow conditions does not exist, depending on the specific application, one technique may be more appropriate than another. Hence, the Operator must choose between techniques for a given MFM installation.

2.6.2. Health, safety and environmental issues

Until a few years ago, MFM’s containing nuclear sources used to be regarded as a Health, Safety and Environmental (HSE) concern. However, the low radiation levels of today’s meters and the flexibility of the source disposal agreements between manufacturer and client have meant a much wider acceptance of this type of meter by government departments.

2.6.3. Measurement intrusiveness

Whenever wax, scale, asphaltene or sand are likely to be deposited in the production system, intrusive devices are clearly not the best solution. Not only will the meter cease to function properly if materials are deposited within the device itself, but the intrusion of the device may only serve to reduce the available flow area to significant degree. This potential to create a flowline blockage makes intrusiveness a HSE issue.

2.6.4. Gas void fraction

It is accepted that the majority of measurements obtained with MFM’s exhibit a larger error for GVF greater than 90%. For applications operating at GVF over 90%, wet gas meters are currently available to the industry. Wet gas metering solutions will be discussed in detail in Chapter 6.

2.6.5. Operating envelope

There is no tool in existence which can cope with the entire range of operating conditions of GVF, flow rate, pressure, water cut (WC) and flow patterns. Hence, it is fundamental to accurately define the operating envelope to be covered by a meter when selecting the appropriate MFM.
2.6.6. Tool dimensions

From a manufacturer’s view, there is virtually no limit to the diameter of a MFM. However, due to the highly unpredictable nature of multiphase flow it is unwise to upscale the results of small diameter tool performance without carrying out dedicated tests on larger diameter tools. The main limitation in obtaining results at a larger scale is that the test facilities available worldwide only cover a limited range of pipe diameters.

2.6.7. Calibration over field life

Although some manufacturers claim that their products do not require further adjustment after the factory calibration, it is unwise to neglect the dependence of a MFM’s performance on the range of conditions (upstream conditions, fluid properties, etc.) over which they have been certified. The parameters affecting the accuracy of MFM measurements will be discussed in detail in Chapter 5.

2.6.8. Costs

Obviously, all Operators should attempt to select MFM solutions that are associated with minimal capital outlay and lower operational costs.

2.6.9. Assistance from manufacturers

When purchasing MFM’s, Operators tend to buy other services from the manufacturers, such as training of in-house staff, but it is essential to guarantee some long-term technical assistance and co-operation, in the event of failure or malfunction of any part of the metering system.

2.6.10. Marinisation experience

The subsea environment is much more hostile and challenging than topside installations. Not all manufacturers provide subsea MFM’s and among those who do, not many have substantial previous marinisation experience. An Operator looking at a subsea installation should be seeking manufacturers who have a proven track record in the field and can also assist with maintenance and replacement, if needed.

2.6.11. Meter orientation and location

Some MFM’s must be installed vertically, while some others horizontally due to the layout of the production system. For a particular configuration of flowlines, one MFM option can be better than another, not just in terms of
fitting into the available space, but also with regards to the flow regime entering the meter. For example, some tools require a certain length of straight pipe (usually expressed in terms of number of pipe diameters) or a flow conditioner upstream of the tool itself to guarantee specific flowing conditions within the meter.

2.6.12. Standalone versus integrated package

Some MFM manufacturers offer meters as part of a larger package of integrated solutions for reservoir management and production optimisation, which obliges Operators to decide whether integrated packages are preferable to separate components. Those Operators with in-house capabilities may lean more towards exploiting the advantages of MFM as an interdisciplinary solution that spans from pure metrology to petroleum engineering.

REFERENCES