Listening to the flow

Measuring the flow of gas and liquids moving together through pipes is a notoriously difficult challenge. *Malcolm Brown* learns more about BP's initiative in developing a sonar-based flow metering technology which is now proving its worth in the company's operations around the world

Quantifying the rate at which hydrocarbons flow from producing wells is a fundamental requirement for helping operators manage reserves more efficiently. Understanding which wells are delivering more or less oil or gas gives an insight into the performance of different parts of a reservoir, and helps to allocate output coming from separate reservoirs making up a larger asset. The information also assists in field development planning and in prioritising well workovers. Taken together, the net benefits can be measured in tens of millions of dollars.

But accurately measuring these flowrates is not an easy task. When fluids flow from hydrocarbon reservoirs they almost always do so as mixtures of gas and liquids – a multiphase flow made up of natural gas, oil and water. There is usually a dominant or 'continuous' phase – the liquid or the gas – carrying along a smaller proportion of gas or liquid. For instance, natural gas coming from wells is often 'wet', typically being a mixture of more than 95 per cent gas by volume and up to five per cent liquids – the liquid can be condensate or water, or both. Determining just how much there is of each component moving through a pipeline – without first separating the liquid and gas phases into different streams – is tricky to do.

Traditional flow meters such as orifice plates or turbine meters inserted into pipelines are designed to measure single phase flows; they also need careful calibration, and present operational challenges and costs associated with installing and maintaining them. Another option, ultrasonic meters, can be clamped onto the outside of pipes and hence are not subjected to the passing of fluids, offering a non-intrusive method to monitor production, but these too can be thrown out of kilter by the presence of a small fraction of liquid or gas. The 'obvious' solution of using large separation vessels to split the liquids and gases into separate streams before they are measured can be prohibitively expensive, hence it is usually not practical to obtain continuous measurements at every well spread around numerous locations in oil and gas fields.

To tackle this industry-wide flow measurement problem, engineers in BP set out a few years ago to develop a more reliable and cost-effective method for continuously metering hydrocarbon flows.

'BP had a vision that a different technique, that of sonar-based measurement, could hold the answer to this,' says Nicolas Morlino, research and development programme manager with BP's exploration and production (E&P) technology group in Houston. 'From our in-depth knowledge of flow measurement methods built up over many years, we knew that sonar flow measurement is not so readily affected by the presence of small percentages of liquids or gases in the continuous phase. And the way sonar metering technology works meant it could be achievable without inserting anything into the flow itself.

'While there were examples of sonar flow measurement being applied to slurries in the mining industry, BP wanted to investigate the technology further and understand the practical issues involved in applying sonar flow metering to oil and gas applications. Hence we set up a trial in 2004 on a wet gas pipeline in our Alaska operation to compare measuring techniques and metering devices.'

> BP decided to apply sonar technology to measure the flow of oil and gas mixtures

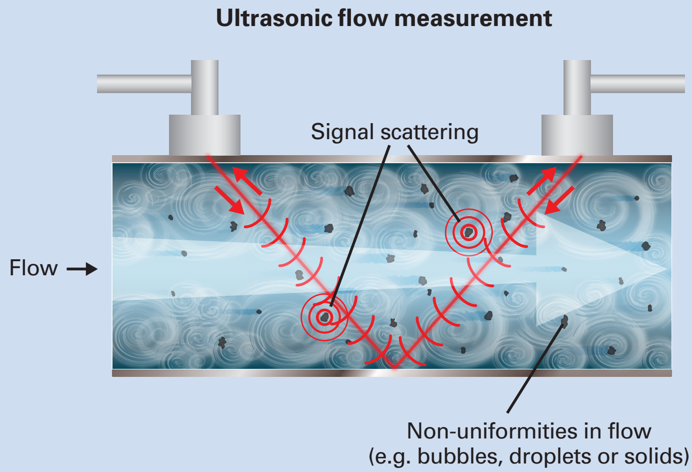
As a result of the trial, in 2004 BP began working with US-based CiDRA Corporation, manufacturer of a patented clamp-on sonar-based flow meter which gave satisfactory results in the Alaska trials. BP has since worked with CiDRA in developing and improving the meter for use in continuous monitoring operations in oil and gas fields, both onshore and offshore. Four years on, the success of the collaboration, drawing on BP's expertise of flow measurement and backed up by test results from the company's oil and gas fields around the world, is changing the way BP monitors wet gases and other flows. In the process, BP has pioneered the introduction of a new and very useful tool into the wider oil industry.

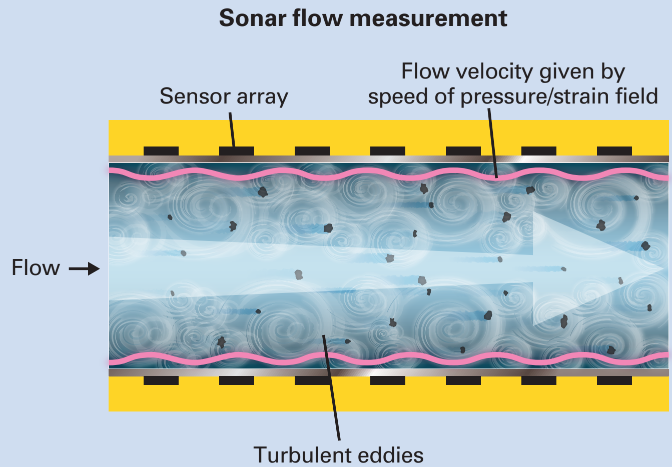
Passive listener

So what is the key to sonar-based measurement and how does it differ from ultrasonic technology?

Ultrasonic flow meters – of which there are many varieties – are effective for measuring clean liquid flows with no entrained gas or solid content, or dry gases. The most commonly used type works by transmitting ultrasonic signals through the pipe wall into the flow in two directions. One sound signal propagates in the direction of flow, the other one against the flow. The signals are reflected back from the opposite side of the pipe and picked up by receivers on the pipe wall, but the two transit times are different – the sound moving against the flow is

FLOW MEASUREMENT WITH SOUND: ULTRASONIC VERSUS SONAR





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Sonar meters do not emit sound, but 'listen' passively to flow activity that is occurring within the pipe, created by turbulent eddies in the flow. These eddies move down the pipe at or near the volumetrically averaged velocity of the flow itself. The eddies are stable enough for their passage to be sensed by an array of pressure-based or strain-based sensors. These are located on the pipe's outer wall at closely spaced intervals within the clamp-on meter. In terms of time, the sensors are spaced axially along the pipe only milliseconds apart. By determining the speed of the eddies moving past, the volumetric flowrate can be derived from the pipe's cross-sectional area. Measurement accuracy of around one per cent is possible for single phase flow, and within five per cent for mixed flows such as wet gas.

> slightly slowed down. The flow rate is derived from the difference in transit times for the two signals to get from transmitter to receiver, effectively measuring the average velocity of the fluid along the path of the ultrasound beam. While the technique works well in single phase flows, the signals can be severely degraded when they encounter another phase – such as the presence of liquid droplets in wet gas.

'Sonar meters get round this problem by doing away with the ultrasonic pulse,' explains Morlino. 'The sonar flow meter doesn't generate sound. Instead it "listens" passively to flow activity that is already occurring within the pipe.'

The flow activity he refers to comes from turbulent eddies in the flow – like tiny whirlpools – which move down the pipe at or near the volumetrically averaged velocity of the flow itself (see diagram above). The eddies are stable enough for their passage to be sensed by an array of pressure or strain-based sensors located on the pipe's outer wall at closely spaced intervals within the clamp-on meter. In terms of time, the sensors are spaced axially along the pipe only milliseconds apart. By determining the speed of the eddies moving past, the volumetric flowrate can be derived from the pipe's cross sectional area. Measurement accuracy of around one per cent is possible for single phase flow, and within five per cent for mixed flows such as wet gas.

The sonar meter has two main functions, explains Morlino. The first is flowrate metering, for example for monitoring gas as it comes from wells, for which a meter is clamped onto the pipeline immediately downstream of each individual wellhead.

'The meter will give you the rate of the continuous phase, so on a wet gas line it will give you the flowrate of the gas phase to within five per cent accuracy, which is sufficient to tell you which areas in the reservoir are producing most or least gas.'

Flowrate metering is particularly useful for improving what is known as operational allocation. Generally on oil and gas fields the fluids produced from several wells are commingled – that is, they are combined and flow through a single pipeline to separation vessels where the bulk of the oil, water and gas are separated. But if production engineers are to make the most of their fields they need to know more precisely what is flowing from each well before commingling to allocate the total production between wells. Because clamp-on sonar flow meters are more robust than other types of flow meter in wet gas conditions, they give a much clearer picture of what is coming from where.

The second function of the meter is to determine the gas void fraction (GVF) of the mixture, that is, the volumetric fraction of gas within a pipe containing both gas and liquids. For example, a GVF of 10 per cent means that the pipeline contains by volume 10 per cent of gas and 90 per cent of liquids. Knowing this is very useful to operators of process plant.

Gas void fraction monitoring is a breakthrough in process measurement technology

'GVF monitoring is a breakthrough in process measurement technology,' notes Morlino. 'By clamping the meter onto existing lines in the process plant we can obtain online real-time measurement of the amount of entrained gas or air present in any liquid-continuous phase fluid. The amount of entrained gas is determined using processing techniques to calculate the speed at which sound propagates through the process medium. In bubbly liquids, the sound speed can then be correlated to a GVF measurement.'

Sonar solutions

Installation of the meter by clamping it onto a pipe takes only around an hour – the meters can be fitted to pipes up to 0.9m in diameter, they do not need calibration in the field, and they are cost effective. BP, the first company in the oil and gas industry to apply the technology in the field to meter production rates, has already deployed around 45 sonar flow meters around its operations. Eight of these, with more scheduled to follow, are on the Greater Cassia platforms offshore Trinidad where, for a variety of technical reasons, difficulties had been experienced in measuring gas flows with existing equipment. The sonar devices are helping avoid over-allocating production from one platform at the expense of another, as has happened in the past.

'Metering helps with operational allocation,' says Bruce Packard, reserves authority for BP's Trinidad and Tobago strategic performance unit. 'Having accurate production information helps in the decision making process when we are considering big capital investments to increase production.'

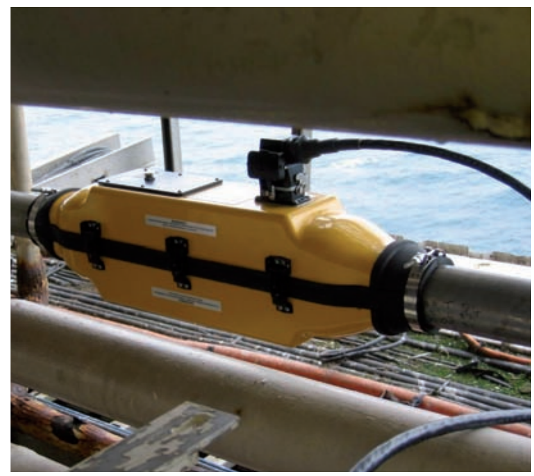
The meters have shown themselves to be the only clamp-on devices that are consistently capable of accurately metering gas in wet gas lines on the platforms, and might eventually help with fiscal allocation. Individual wells are often owned, or part owned, by several different companies. If revenues are to be fairly distributed it is essential to know precisely how much each company's wells contributed to the commingled whole.

'If you misallocate production someone can get allocated too much money and somebody else too little,' says Packard. 'Improving our metering gives us more confidence in the accuracy of the production allocation and prevents this.'

Another area where sonar metering could be very useful, says Morlino, is in metering gas or water injection. Gas or water is injected into some reservoirs to maintain pressure or reduce oil viscosity and sweep out hydrocarbons which cannot produce sufficiently on their own. Engineers want to know which wells will produce the most oil for a given volume of water or gas injected so that they can concentrate resources on them. At present, clamp-on ultrasonic meters are often used to monitor injection. But as well as being sensitive to the presence of small gas or liquid volumes in the flow, ultrasonic meters can require significant maintenance.

'At any one moment,' explains Morlino, 'a substantial number of ultrasonic meters might not be working, so, in certain locations, perhaps as much as 10 per cent of the water injected cannot be accounted for at the wellhead. In injection applications, BP already has nine clamp-on sonar meters metering water injection flowrates in Egypt for BP's Gulf of Suez asset, but the real prize will be Alaska, where there are hundreds of injection wells, together injecting over two million barrels of water a day.'

In addition to injection flow monitoring, in BP's Prudhoe Bay asset in Alaska the second function of the sonar flow meters – the measurement of GVF – is also particularly relevant. Here, an increasing proportion of the oil produced is viscous – it is sometimes so thick



BP's Cassia platforms offshore Trinidad (top) have had CiDRA sonar flow meters installed on well flowlines (above and left)

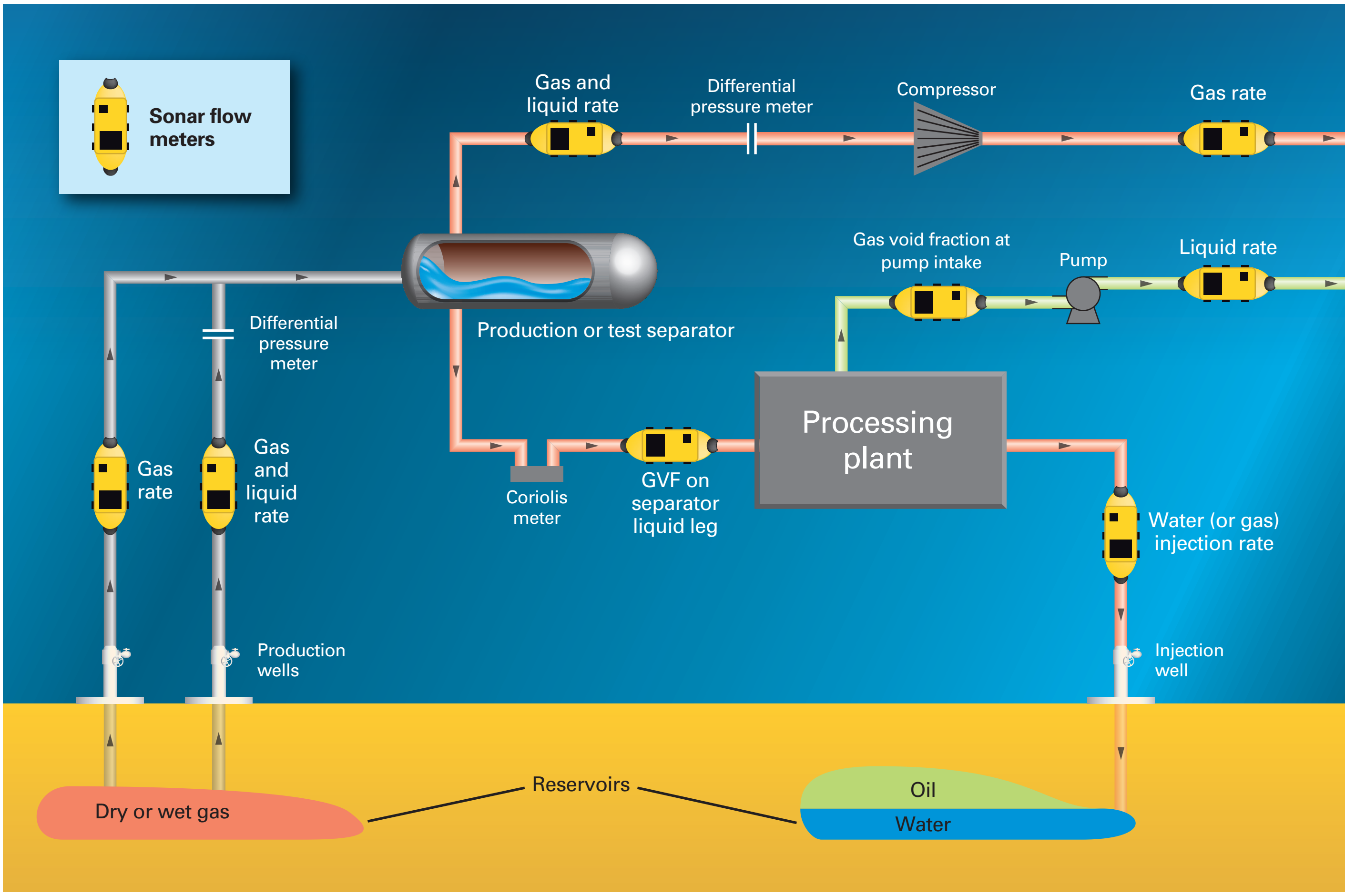
that gas can become trapped in it. The oil holds on to the gas so tenaciously that even after it has been passed through a test separator designed to separate the liquid and gas phases, there is still some gas left in the oil.

'The primary job of test separators is to determine production coming from individual wells in the field,' explains Eric Ward, BP's technical authority for metering in Alaska. 'Their use is often insisted upon by regulatory agencies in preference to other measuring devices. Test separators have only two outlets. There is a gas outlet and a "liquid leg" at the bottom of the vessel which drains off all the liquids – oil and water together. The water does not need to be separated from the oil because the water cut, that is, the proportion of water in the oil/water mix, can be measured using a Coriolis meter – a type of mass flow measuring device which can accurately differentiate between water and oil by virtue of their different densities. Armed with the total liquids rate and the water cut, the production of both oil and water can be calculated.'

This approach provides valuable information for those trying to optimise well operations. But there is a snag. The high viscosity of the oil in certain regions of Prudhoe Bay means the operation of the test separator is sometimes imperfect, resulting in some of the gas being entrained in the oil and finding its way into the liquid leg. This 'gas contamination' in turn distorts the Coriolis meter, which is designed to measure liquid flows based on mass and density.

'The Coriolis meter assumes that it's seeing all liquid with no gas in it,' says Jerry Brady,

APPLICATIONS FOR SONAR FLOW METERS



petroleum engineer in BP's Alaska technology directorate. 'So if there is even a small volume of gas in the liquid stream it will lower the density significantly. The calculation will show that there is more oil there than there really is.'

Indeed, BP has determined that one per cent entrained gas in the oil/water mixture in the test separators in Prudhoe Bay can lead to the water cut being understated by five per cent and the gross fluid flow overestimated by one per cent. This is where the sonar flow meter and its GVF measurement function come in. If a sonar meter is clamped to the liquid leg of the separator it can calculate the volume of gas that has become trapped in the oil/water mix. From that, engineers can apply a correction factor to the Coriolis meter readings to give a precise picture of what is going on.

The alternative would be to heat the multiphase stream before it enters the separator to achieve efficient separation, but this would be vastly more expensive – at least $1 million per separator in capital expenditure plus the cost of installation.

More to meter

The liquid leg challenge is encountered on wells in the western side of Prudhoe Bay. In other parts of the field, says Brady, the sonar meter may help to deal with a different problem. In these areas there is a large amount of gas, and Prudhoe Bay has limited gas handling facilities.

'What we want to do is produce the wells that have the most oil for the least amount of gas,' explains Brady. 'The only way we could do that in the past was to get a well test from those wells maybe once a week at best, sometimes once a month. Using the sonar meter in combination with other meters it will be possible to monitor wells continuously to establish the gas-to-liquid ratio. It will be cost effective to install a meter on every well to allow us to monitor them all continuously to provide us with a picture of which wells to focus on for optimising oil production.'

> It will be cost effective to install a meter on every well for continuous monitoring

While other companies have now begun to use the meters, BP is leading the way. But even so the company believes there are still more opportunities where the meter could bring operational benefits, explains Morlino.

'Besides wet gas production and GVF metering, the meters could be used to improve the monitoring of gas injection in Alaska and in other assets, as we are already doing on water injection wells. And there is an in-well version of the sonar meter which has already been successfully installed in Trinidad. Ultimately, sonar-based flow meters might be used for metering flows in the offshore subsea environment.'

As Morlino points out, these applications are just in upstream operations. BP has now deployed the meters in its refineries in the USA and sees numerous applications in its wider downstream operations. And the company is continuing its collaboration with the manufacturer to develop a two-phase version of the meter – BP has identified that by combining sonar flow measurement with additional measured parameters, such as the pressure drop in a flowline, both the liquid rate and the gas rate on a wet gas flowline can be determined. BP has proven this additional breakthrough in practice and expects to deploy the technique in the field by the end of this year.

It appears that measuring hydrocarbon flows which contain small but troublesome percentages of liquids or gas may be less problematic in future thanks to BP's creative vision for sonar flow measurement. ■