This year’s pipeline flow Q&A asks industry experts to weigh in on pipeline operational conditions, computational fluid dynamics, the technologies used in flowmeter applications and more!

Read on for insight from Cameron, a Schlumberger company; Endress+Hauser; Honeywell; and Thermo Fisher Scientific.
Cameron, a Schlumberger company, USA
Gregor Brown

What care is taken in the application of flow measurement technology?

Given the myriad of flow measurement technologies on the market today, the first challenge is to select an appropriate meter for an application with regards to accuracy, robustness, ease of installation and cost. Even when a technology preference has been stated - for example, an ultrasonic flowmeter - the user is still faced with a range of models from different manufacturers. A diligent manufacturer would consult with and guide users to the appropriate meter model for their application.

Some applications require more specialised products. For instance, if an ultrasonic technology was selected for custody transfer of medium and high viscosity oils, then the user would require a meter that performs with a high level of accuracy through the laminar-turbulent transition region. For that, Cameron engineers use a special variant of ultrasonic meter that has a reducing nozzle prior to the ultrasonic metering section.

Different meter types have different installation requirements, depending on technology and design. Typically, the installation requirements are stated in terms of upstream and downstream straight pipe lengths. However, for some technologies, there may be different requirements. For Coriolis meters, it is important not to place undue strain on the meter body, while for ultrasonic meters, it is common to require flow conditioners for custody transfer applications.

However, the latest generation of ultrasonic flowmeters can be installed without flow conditioners and can still achieve the very highest standards of performance. For example, Cameron has recently supplied a large border station in Europe with 30 in. eight-path ultrasonic meters, which will be installed without flow conditioning. The meters were selected because of their compliance with the highest accuracy class of the Organisation Internationale de Métrologie Légale (OIML) R 137 standard.

Flowmeter users should recognise that although the measurement uncertainty is stated as a ‘plus and minus’ value, it is made up of both random and systematic effects. Therefore, a constant bias of less than the total uncertainty is possible. This could result in a pattern of consistent under or overpaying in the custody transfer process, thus driving demand for highly accurate meters. Flowmeter accuracy comes at a cost because manufacturers have to invest heavily in product development in order to achieve the low uncertainty that is required for a flowmetering cash register status.

How could flowmeters be described as the ‘cash register’ of the oil and gas industry?

In custody transfer applications, the amount paid for the quantity of fluid received is based on the volume or mass registered by the flowmeter as well as the quality or composition of the fluid. In that sense, the flowmeter acts like a cash register. However, there is an important difference. A cash register totals the cash to the exact cent or penny, as long as there is no human error or fraud. With flow measurement, there is always an element of uncertainty. In other words, the quantity of fluid registered will always be an amount plus or minus some uncertainty of the measurement system. A flowmeter with a low measurement uncertainty makes a good cash register. A system with an uncertainty of ±0.20% vs one with ±0.25% reduces uncertainty by 0.05%, which can amount to a large financial exposure for both the buyer and seller. An additional uncertainty of 0.05% in a custody transfer of a batch of 500 000 bbls of oil at US$50/bbl is worth US$12 500. That may not sound like much, but that is for only one transfer. Over the life of a measurement system, that figure can easily accumulate to a massive total value.

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What are effective pipeline monitoring methods for leak detection in oil and gas applications?

There are a number of means of leak detection for oil and gas pipelines; one being physical detection of rupture events or leaking product. For large-scale pipelines, the most effective means of leak detection is computational pipeline modelling that uses live flow, pressure and temperature inputs. As with any computer model, the effectiveness of the leak detection system is dependent on the accuracy of its inputs – pipeline diameter, elevation and other parameters – and on the uncertainty of the measurement inputs (flow, temperature and pressure). This demand for improved certainty drives similar accuracy requirements for leak detection as those in custody transfer applications. Thus, the lower the uncertainty of the flowmeter, the greater the accuracy, speed and certainty of the leak detection system.

Have there been any recent challenges for operators with regards to pipeline integrity and flow assurance?
In general, pipeline operations have not dramatically changed over the past 40 years. However, there are two significant developments worth noting. First, an increased focus on environmental responsibility has driven pipeline operators to demand leak detection systems that can detect leaks faster, with greater accuracy and minimal false alarms. In turn, this drives a demand for high accuracy and greater reliability in flowmeters.

Secondly, multiproduct oil pipelines are now transporting a more diverse range of products. The same meter has to perform with low uncertainty on both low and high viscosity products. The operator’s role includes selecting, calibrating and installing flowmeters that can perform with low uncertainty over a full product range. This choice must be made carefully to ensure successful long-term operation.

How often should a pipeline be pigged without impacting the flow regime?
Deciding how often a pipeline should be pigged to remove wax, or other forms of deposition, is best based on previous pigging experience on that specific pipeline. A prolonged interval between pigging could allow wax to build up so much that it becomes increasingly difficult to remove with the pigging operation. Pigging that occurs too infrequently could also lead to an excessively large wax plug, which could, in turn, result in blockages at the receiving facilities. If the interval is too short, there is unnecessary cost and risk. As for intelligent pigging for integrity checks, the pipeline’s age and history must be considered, alongside other factors.

What areas or applications need to be focused on to provide effective systems and automate/improve your pipeline data flow?
Pipeline automation and automatic leak detection rely on accurate and reliable flow measurements. In automation and control applications where the relative performance is more important than absolute accuracy, a relatively low accuracy flow measurement would suffice. For example, to increase flowrate, the feedback that the flowrate has indeed increased is needed. However, for control purposes, it is not critical to measure flowrate to the nearest 0.1% or 0.2%.

As for leak detection, even when flowmeters are operating inside of their rated uncertainties, a measurement bias of 0.2% at one meter, followed by a bias of -0.2% at the next meter in the line would look like a leak of 0.4%. Therefore, a key focus for automated leak detection is flowmeter performance and, in particular, the reduction of fluid hydraulic effects. As a result, pipeline operators are moving towards more accurate technologies, such as eight-path ultrasonic meters, which offer all of the benefits of a nonintrusive meter with no moving parts and low measurement uncertainty.

What are the benefits of computational fluid dynamics?
The main benefit of computational fluid dynamics (CFD) is that it can be used to provide insights into flow phenomena in pipelines, flowmeters and fluid machinery. In some cases, it can be used effectively to quantify flow parameters, such as calculating pressure losses. However, for high accuracy flow measurement applications, CFD data is not currently sufficient to enable a user to accurately predict or calibrate the measurement error on its own. When coupled with experimental data, CFD data becomes more robust and can be a very useful design tool.

Understanding why one design performs differently to another can be difficult using only test data. CFD offers insight into what the flow is doing inside the component, making it easier to see why one design performs differently from another and guiding the design process.

How is a flow measurement tool chosen in pipeline operations?
When selecting a flowmeter, the user should consider the accuracy requirements, application conditions and operational considerations for the pipeline in question. For large diameter oil and gas pipelines, ultrasonic flow measurement is becoming dominant due to the inherent benefits of the technology. Since ultrasonic flowmeters have no moving parts or parts that intrude into the flowline, pressure loss is virtually eliminated when the fluid flows through the ultrasonic meter. In other words, the pressure loss is as negligible as that in a short section of pipe.

Once a technology is selected, care is still required to ensure that the specific meter model is suitable for the application conditions. Meter designs from different manufacturers will vary in their features and benefits that can translate to significant cost savings. For example, four-path ultrasonic meters generally require a flow conditioner that is installed upstream to satisfy the accuracy requirements for custody transfer or leak detection. In contrast, eight-path meters achieve the same performance without requiring an upstream flow conditioner. This benefit of eight-path meters can translate into millions of dollars of savings in operational costs over the lifetime of a pipeline.

What applications of diagnosing meter performance have been the most successful?
Modern technologies, such as ultrasonic and Coriolis meters, have much more advanced diagnostic capabilities compared...
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with traditional mechanical technologies like turbine or positive displacement flowmeters. Ultrasonic and Coriolis meters can analyse the electronic signals they receive and determine the quality of the raw measurement input as well as infer information about the process conditions and the interaction between the measurement equipment and the flow.

Multipath ultrasonic meters have the most advanced suite of diagnostic capabilities because they can provide information on the performance on a per-path basis – for each transducer pair – as well as path-to-path comparisons, such as comparing sound velocity results from path to path. Additionally, these meters can combine multiple-path velocity measurements to characterise the flow velocity profile.

Ultrasonic meters with four paths require flow conditioning to make effective use of velocity profile information. Without straightening the flow, they cannot decipher flow that contains both variations of the axial flow profile and nonaxial flow, known as swirl. Ultrasonic meters with eight measurement paths that are arranged in crossed pairs have the ability to resolve both axial and nonaxial flow. Not only can they effectively diagnose flow conditions without a flow conditioner, they also have a larger group of measurements for path-to-path diagnostic comparisons.

Significant advances have already been made in the diagnostic capabilities of ultrasonic meters and the new developments underway in this area will lead to even higher self-verification capabilities.

Endress+Hauser, USA
Jerry Stevens

What care is taken in the application of flow measurement technology?

Application considerations include multiple topics – process control, process safety, compliance, fiscal or contractual needs, installation suitability, integration requirements, operator familiarity and preference with a technology and the OPEX and CAPEX goals of the pipeline company.

Care is required to ensure performance of the measurement – including uncertainty, zero stability, temperature and pressure effects – especially during custody transfer. To ensure this, flow devices need lifecycle management involving partial proof testing, calibration, verification and maintenance.

How could flowmeters be described as the ‘cash register’ of the oil and gas industry?

Fiscal measurement is the movement of assets from a seller to a buyer. This transaction is usually contractually bound and may require the assignment of royalties or taxes – hence the aspect of financial accountability, like the cash register.

The flowmeter is the accounting mechanism used to quantify the flow of valuable fluids. The data derived from these meters is then used for a variety of contractual purposes, including revenue to a Bureau of Land Management (BLM) or property owner and internal custody transfer between two business units of an organisation.

What are effective pipeline monitoring methods for leak detection in oil and gas applications?

Loss and gains analysis in pipelines or points of transfer can use modern flow technologies and tank gauging techniques that permit the widest rangeability to identify even the smallest leaks and product giveaways. Large diameter Coriolis meters offer an effective way of ensuring extremely low flowrates for easy mass balance analysis. Tank gauging techniques can also provide redundancy between storage locations in a similar manner. Ultimately, the maximum line losses dictate the technology selection that is most suitable for the specific application.

Have there been any recent challenges for operators with regards to pipeline integrity and flow assurance?

Fiscal meter technologies are subject to measurement drift when flowrates, viscosities, pressure or temperature fluctuations are not accounted for. Pipeline integrity has shown to introduce impurities or contamination if not cared for over time. This can disrupt, if not prejudice, the installed meter technology.

5. What methods are taken if there is improper flow through a pump or compressor?

Improper flow can introduce noise, turbulence or cavitation – all of which are disruptive to normal flow profiles and are challenging some meters which previously showed no out of regulation deviation. If not maintained, compressors transporting gases can escalate the liquid carry under loading to disruptive and unreliable measurement performance, even in the most flexible fiscal meter technology.
What areas or applications need to be focused on to provide effective systems and automate/improve your pipeline data flow?

Fluid and process properties are number one. This can be the fluid density, viscosity, fluid vapour pressure, expected variability of individual constituents (gas), disruptive influences (H₂S, asphaltines, liquid levels, gels or semi solids), flowmeter range of measurement and required turndown.

Installation criteria is number two. This can be the hazardous area definitions, required approvals from nationally recognised testing laboratories, certifications (API, OIML, ASME VIII), added test criteria performed by the manufacturer (pressure, type, x-ray or radiographic) or mounting and wiring conventions (explosion proof or IS requirements).

What are the benefits of computational fluid dynamics?

Analysing fluid scenarios and effects would not be possible without the combination of CFD and finite element method (FEM) modelling. CFD does permit a wide range of fluid profiles, medias and velocity scenarios to be evaluated. The characteristics of phase separation, fluid movement and stability of flow measurement regimes can be evaluated. FEM has also proved to maximise reliability, ensure design conformity and alleviate safety concerns.

What applications of diagnosing meter performance have been the most successful?

Production, lease automatic custody transfer (LACT), pipeline operations and blending have all benefited from the most advanced real time diagnostics, device monitoring of service and system parameters, and the addition of industry recognised in situ verification techniques, performed by a traceable and attested means.

With in situ verification, the need to remove flow instrumentation from a pipeline for calibration in a laboratory is minimised. In some cases, instead of removing a flowmeter for calibration each year, in situ verification can extend this interval by approximately two or three years.

How could flowmeters be described as the ‘cash register’ of the oil and gas industry?

Flowmeters are classified into two categories, fiscal and non-fiscal. Data from fiscal or custody transfer devices is the basis for billing between the buyer and seller of gas and liquid hydrocarbons. As part of the contractual agreements between business parties, these devices have earned the nickname of ‘cash registers’.

What are the benefits of computational fluid dynamics?

In simulation and modelling, the results of CFD are only as good as their closeness of fit to the real world. This means that CFD is best used when the modelling includes a ‘real world’ correlation. As a flow tool, it is certainly one of the most powerful and it has proven to be invaluable on many occasions.

How is a flow measurement tool chosen in pipeline operations?

Flow measurement tools are chosen based on the application’s needs, specifically in terms of pressure, temperature and volume of fluid. Measurement uncertainty, range, repeatability and a number of other performance criterions are also taken into account. Ultimately, there is no one perfect meter for an application, but a compromise based on the application requirements and the expected performance from the meter over its lifecycle.

What applications of diagnosing meter performance have been the most successful?

The most successful applications of meter diagnostics is online, 24 hr/d condition-based monitoring. Today, there are many instances where diagnostics are used in periodic...
periods only, but as this is sample based, it doesn’t show all of the issues that arise. Therefore, continuous monitoring is key to really understanding what is going on in an application and to judge whether something is going well or needs adjustment. The most successful application does not only mean that an error is detected, but is one that also shows that meter performance is good so that no action has to be taken.

**Thermo Fisher Scientific, USA**

Benjamin Fuentes

What care is taken in the application of flow measurement technology?

First, one must consider whether the application is for custody transfer or strictly allocation purposes. For allocation, measurement does not typically involve change of ownership in the product being measured. Therefore, requirements in accuracy, repeatability and maintenance will vary. For custody transfer, however, measurement involves two distinct parties that are contractually obligated to meet all requirements. In all custody transfer applications, applicable standards should be reviewed and adhered to depending on technology, such as ultrasonic, PD meter, turbine, orifice and Coriolis.

In all cases, the primary concern regarding technology should revolve around the product being measured. Factors to consider are line size, pressure drop, viscosity, accuracy, maintenance, surrounding noise and vibration. Ultimately, the technology should be best matched up with the application and users should be sure that their technology provides them with the latest custody transfer compliance standards, with data readily available via direct connection or remote monitoring.

How could flowmeters be described as the ‘cash register’ of the oil and gas industry?

Flowmeters can be classified as the ‘cash register’ as they determine the amount of volume or mass being transported through a particular location. The measurement is then tied to the market value of the particular product and provides the user with a monetary value of the product. This information is extracted from flow devices and imported into accounting software for validation and corrections. Ultimately, it is converted to cash in users’ accounts. Advanced flow computers will calculate and store all measurement data in compliance with industry standards so that end users have a reliable audit trail of all transactions and measurements.

Oil and gas producers will have a general idea of the amount of reserves in a particular field, which provides them with long-term cash valuations. For real-time cash valuations, end users utilise flowmeters and the associated hardware to determine the cash value of assets being produced, transported or sold. These flowmeters are used when product is being transferred to another owner; it provides the volumetric measurement of a product, which is then sent to an accounting system to determine monetary value.

What are effective pipeline monitoring methods for leak detection in oil and gas applications?

The most effective method of leak detection revolves around ‘balancing’ a system. Measurement points are placed in various locations so that measurement into and out of a system can be compared. Many of these pipeline systems are buried in the ground, so small leaks may not be easy to locate. However, by utilising a common platform across pipeline systems when performing ‘balancing,’ end users can compare data in an effective and efficient manner due to commonality of data across one or multiple systems.

Have there been any recent challenges for operators with regards to pipeline integrity and flow assurance?

Currently, Thermo Fisher believes that the pressing challenge on the minds of operators is the age of some of the pipeline infrastructures, along with demands in energy. New technology in flow computers, however, is becoming more widely accepted and implemented in the industry, which is helping to overcome this challenge.

For example, the Thermo Scientific™ AutoEXEC flow computers can be used to automate routine maintenance procedures, gather relevant data and even make any necessary changes, thus assuring the end user that correct data is being utilised and generated.

How often should a pipeline be pigged without impacting the flow regime?

As there is no one specific timeframe that can be applied to all pipelines, the type of pipeline and product being transported will dictate the frequency of pigging. Two primary resources should be referred to in order to determine specific frequency: the Federal Energy Regulatory Commission (FERC) and the Pipeline and Hazardous Materials Safety Administration (PHMSA).

What methods are taken if there is improper flow through a pump or compressor?

Older technology, such as turbines and PD meters, did not allow for proper view of a flow profile within a pipeline. But, with
advancement in ultrasonic technology, it is now possible. The primary methods for addressing improper flow are to measure upstream and downstream straight pipe length. If it is not feasible to change the pipe lengths, it may be necessary to consider flow straighteners, in the form of either tube bundles or a single plate with various holes.

What areas or applications need to be focused on to provide effective systems and automate/improve your pipeline data flow?

This may sound rudimentary, but the right tool should be used for the job. Many factors should be considered and addressed prior to installation, including, but not limited to, pressure drop, viscosity, quality of product, accuracy and maintenance. There are many standards developed by the American Gas Association, the American Petroleum Institute and the Gas Producers Association that provide guidance to installation and operation of all measurement equipment.

The gathering of data from the field/site is also a very important piece of the overall system. A strong communications backbone is critical for handling the current data and any future expansion, it will provide users with valuable information for operating and maintaining a system that may have thousands of measurement points. The latest technology in flow computers provides multiple communication port options to facilitate the gathering and sharing of data. An interruption or failure at any one site could impact the overall system. Therefore, careful consideration should be made when designing a communications system.

How is a flow measurement tool chosen in pipeline operations?

Fundamentally, any tool must provide some value to the end user and must be reliable, effective and easy to operate. To determine which tool to use, the application and impact on other onsite equipment should be considered. Additionally, when selecting tools, one should consider other factors such as cost of ownership, failure history and personal experience.

What applications of diagnosing meter performance have been the most successful?

Many meters are calibrated prior to shipment. However, after many days of continuous operation or operation under harsh conditions, these meters require verification that they continue to operate at 100% accuracy. An effective method for validating a meter’s performance is an offsite verification or calibration at a testing facility that has the ability to duplicate a variety of different flowing conditions to validate a meter’s performance. Offsite calibration requires removal of the instrument. Therefore, it is not uncommon for users to have a spare calibrated meter to rotate in during the verification/calibration process.