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Flow Measurement
PART 2

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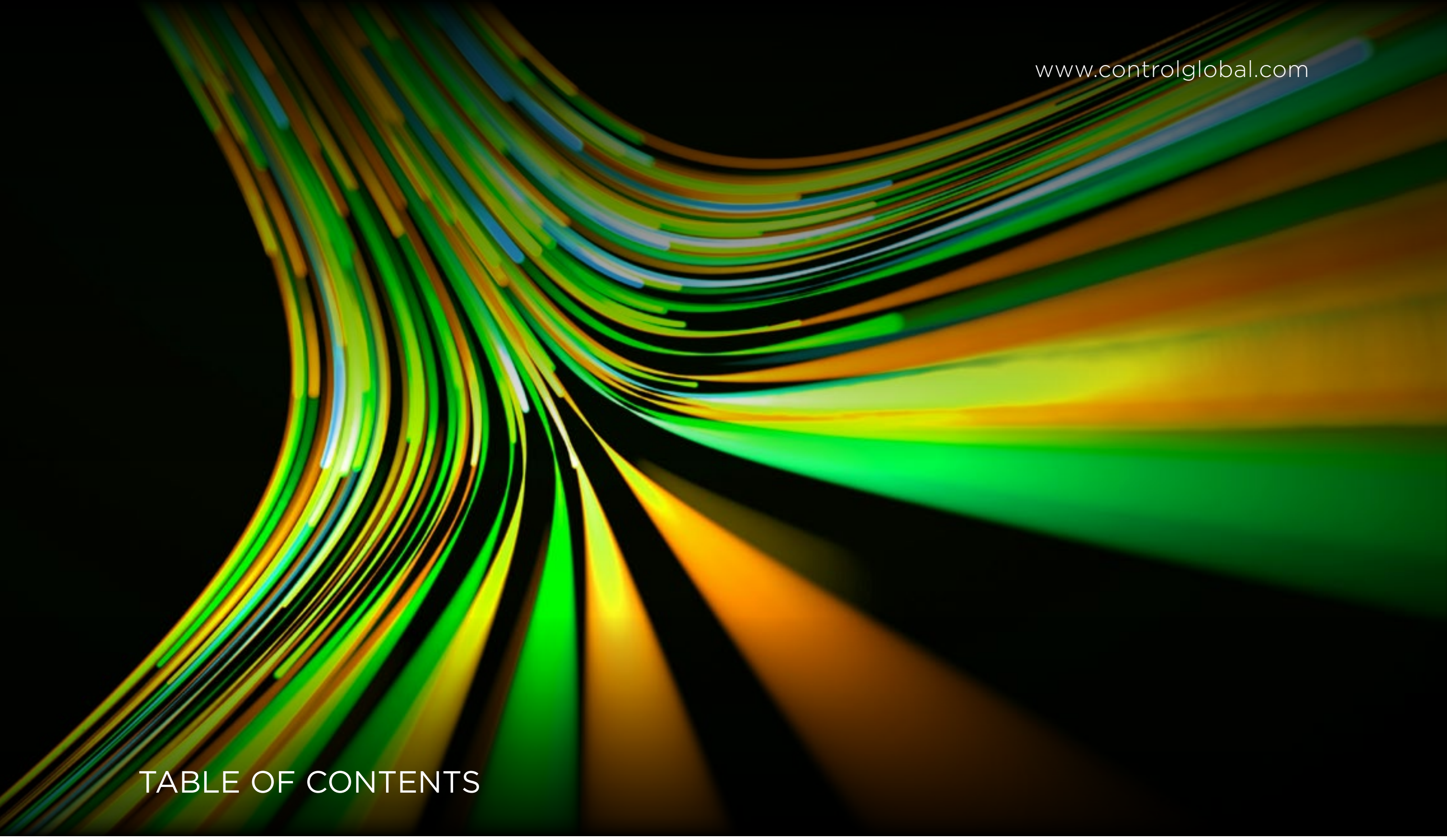

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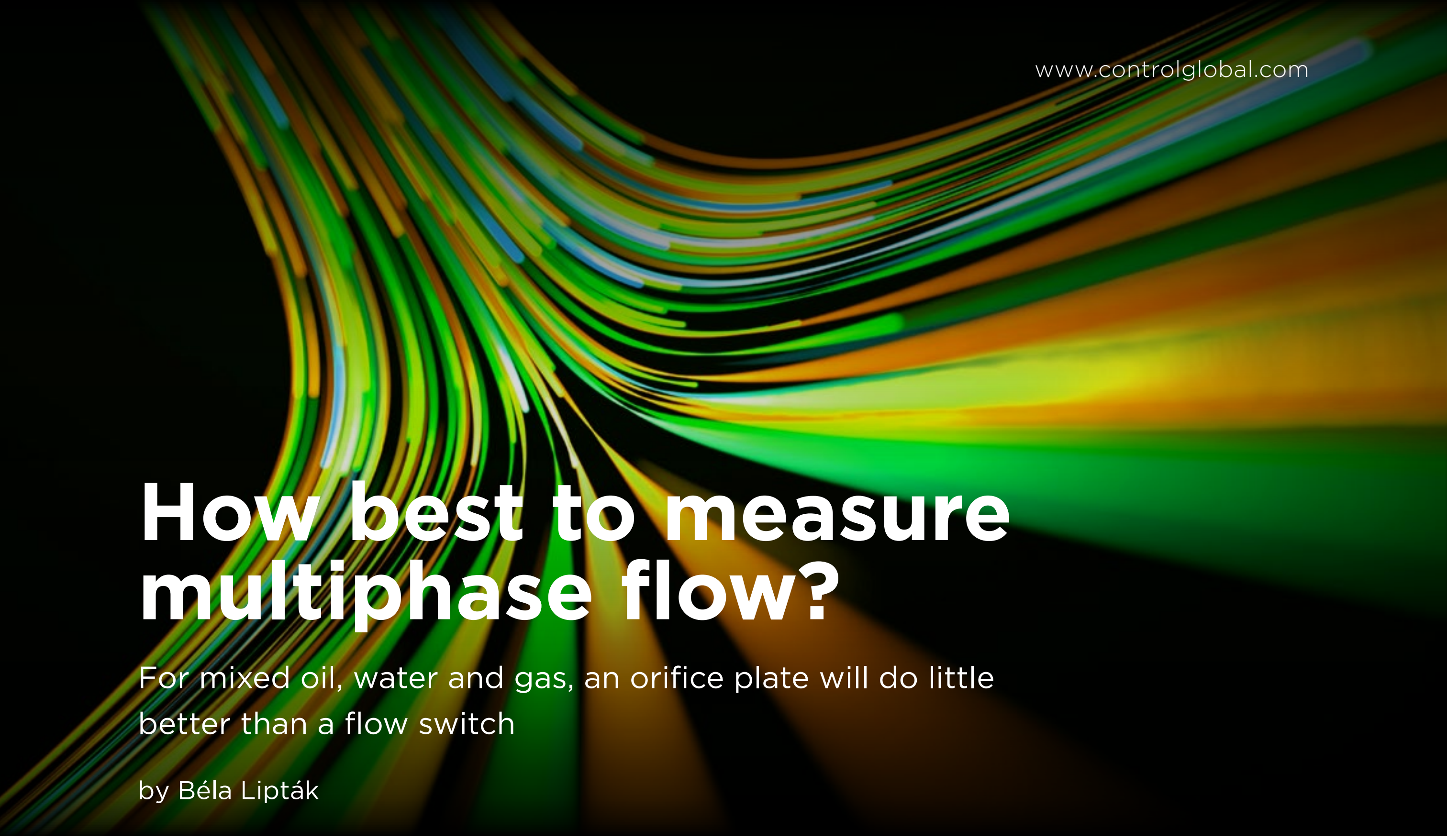

How best to measure multiphase flow?

For mixed oil, water and gas, an orifice plate will do little better than a flow switch

by Béla Lipták

Q: We need to measure an oil/water/gas multiphase flow using an orifice plate. The gas-oil ratio (GOR) is 80% and the water cut is 15%. The flowmeter is to be in the production flowline near the wellhead, upstream of the production separator. I know that this location of an orifice meter is not ideal, but our client insists. Further, the line size can't be changed because of process design criteria.

We have a separate flow control loop at this location, so highly accurate measurement isn't our concern. It can be inaccurate. Rather, I need to find a simple way to size the orifice plate as accurately as possile. In your opinion, can I calculate the size of three orifices for the three phases, and add up their areas to get the size proper size for the three-phase flow? Considering all this, please give me your best advice.

Pooyan Ebrahimi

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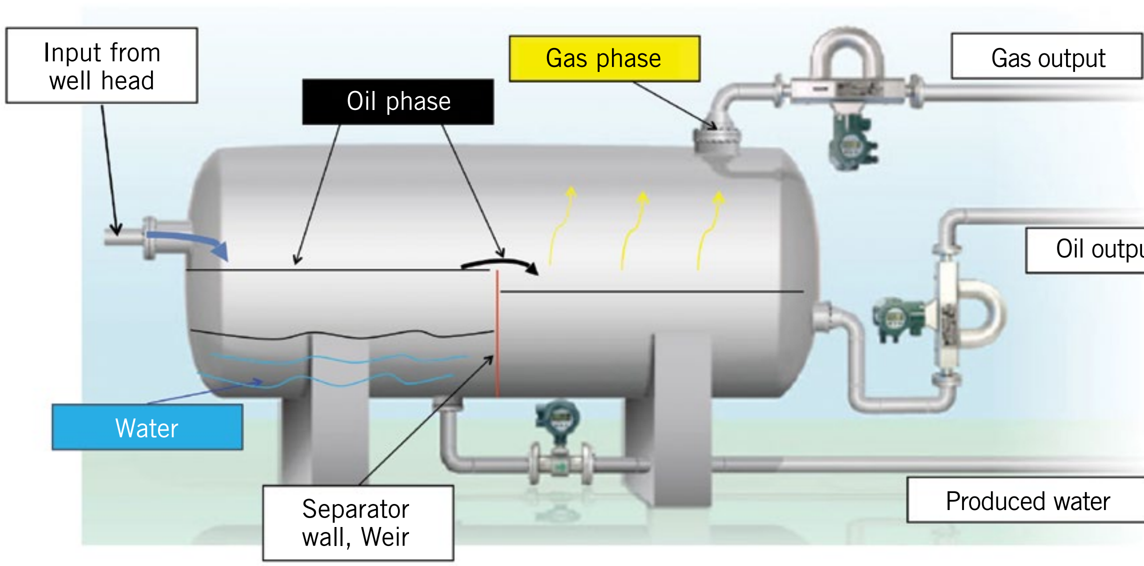
A1: In your process description, you indicated that measurement accuracy isn't important, but you didn't say what is important, what the purpose of the measurement is? I assume your purpose is just to alarm if drastic changes occur in the total flow or if the oil-gas ratio (OGR) suddenly changes. In other words, the purpose of your installation is like that of a flow alarm, and therefore it's sufficient for this sensor to act like a flow switch. In any case, I'll first make a few general comments about measuring multiphase (oil, gas, water, solids)



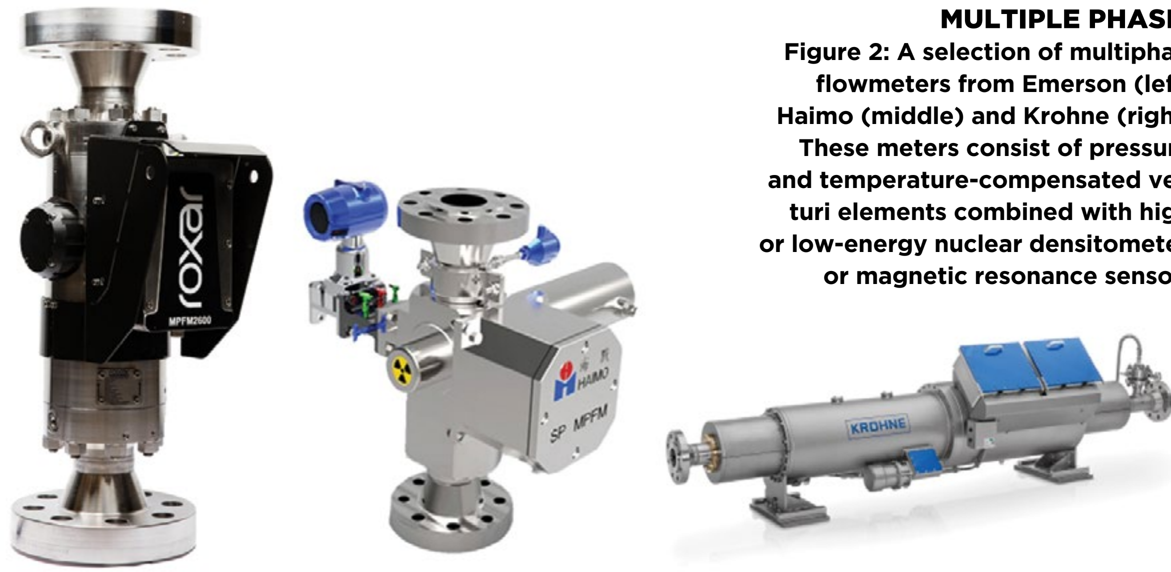
POST-SEPARATOR FLOW MEASUREMENT

Figure 1: The most accurate—but not the timeliest—way to measure well-head output is to use flowmeters on the separated gas, oil and water streams. (Image courtesy of Yokogawa)

flows from oil wells, and after that I'll answer your specific question.

Naturally, the most accurate method of measuring multiphase flow is to first separate the components of the total stream, and only then measure the flows of the individual components leaving the separator, using high precision flowmeters like Coriolis (Figure 1). I understand your client doesn't want to do this because they want to know about any flow changes as soon as they occur. If they desire to place the flowmeter before the separator, or if the purpose of the installation is to eliminate the individual separators, then using multiphase flowmeters is a possible option.

There are several multiphase meters on the market (Figure 2). They usually consist of pressure- and temperature-compensated venturi elements combined with high- or low-energy nuclear densitometers or magnetic resonance sensors. These meters can distinguish the flow rates of oil, gas and water, but suffer serious limitations. They can also reduce the amount of hardware on the topside of the well (onshore) or can be placed on the platform in offshore applications. In offshore applications, if they're designed for high-pressure and low-temperature operation, they can also be placed in the ocean. In both cases (onshore or offshore), they can eliminate



FLOWMETERS DESIGNED FOR MULTIPLE PHASES

Figure 2: A selection of multiphase flowmeters from Emerson (left), Haimo (middle) and Krohne (right). These meters consist of pressure- and temperature-compensated venturi elements combined with high- or low-energy nuclear densitometers or magnetic resonance sensors.

well-testing lines, which can be long and expensive, while measuring OGR or flow in real-time eliminates the separation delay.

Now, coming to your question concerning the use and sizing of orifices for approximate measurement: as you suggested, approximate sizing of these plates can be obtained by separately calculating the area requirement of the three flows (one for the oil, one for gas and one for water), and adding up these areas to arrive at the total area of the measuring orifice opening. If solids are also present, segmental plates can be considered.

If you want to increase the rangeability of this inaccurate (flow-switch quality) sensor, you can install an orifice changer with two different size plates. When using orifice changers to increase rangeability, you can have automated controls that will provide automatic switching of the differential pressure ranges that reflect the flow ranges of the two orifice plates.

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A2: If you're going to be measuring the combined multiphase (crude, gas, water) upstream of a production separator, the following issues will affect measurement precision and repeatability:

1. As the pressure in the flow line fluctuates, apparent gas flow rate will also fluctuate since the compression will be different.
2. As the quantity of water and solids fluctuate the liquid (crude) flow component will also be affected.
3. As the GOR of each well is different, the overall flow precision will be affected.

Based on these issues, you can have measurement errors on the order of 5% to 10% or as much as 30% to 50%. This is one reason that this sort of meter is only used to indicate or verify that there is flow in the line.

Based on your comment that precision isn't important, I would recommend that you design your measurement system as follows:

1. Select a junior or senior fitting for quick change out of orifice plates as the operation runs.
2. Design it to use a segmental orifice plate with a slightly higher segment profile, so gas compression effects will not be so large.
3. In the calculation, add both a weep and drain hole (oversized on the plate) to prevent gas or solids from impacting the measurement of the segmental section.
4. By using junior and senior flanges, you can have a set of orifice plates with a much greater rangeability, allowing for more precision.
5. Most flow lines are generally between 2- and 8-in. based on expected flow rates. Therefore, when you calculate the orifice make sure that the weep and drain holes are between 1/4 in. and 1/2 in. in diameter, and take these impacts into account in your segmental orifice calculation.
6. Design generally so each orifice plate can handle between 10% and 35- 40% of the total flow of similar flowlines. This way, the range of each orifice is a bit smaller, again giving more precision.

Personally, I'd choose to place a flow switch in the incoming flow line, and then measure the flow of gas, water, crude and solids at the outlet of the separator. This will not only provide more precision, but will also let users detect when issues arise with any particular well.

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Water hammer in vortex flowmeters?

Our experts also address whether to segregate signal and power wiring in cable trays

by Béla Lipták

Q: We have some vortex flowmeters in various sizes of pipes. They seem to have been installed correctly (upstream and downstream pipe runs are OK), but the ones on hot water service are highly inaccurate. We also have water hammering in these lines. What are your recommendations to resolve this problem?

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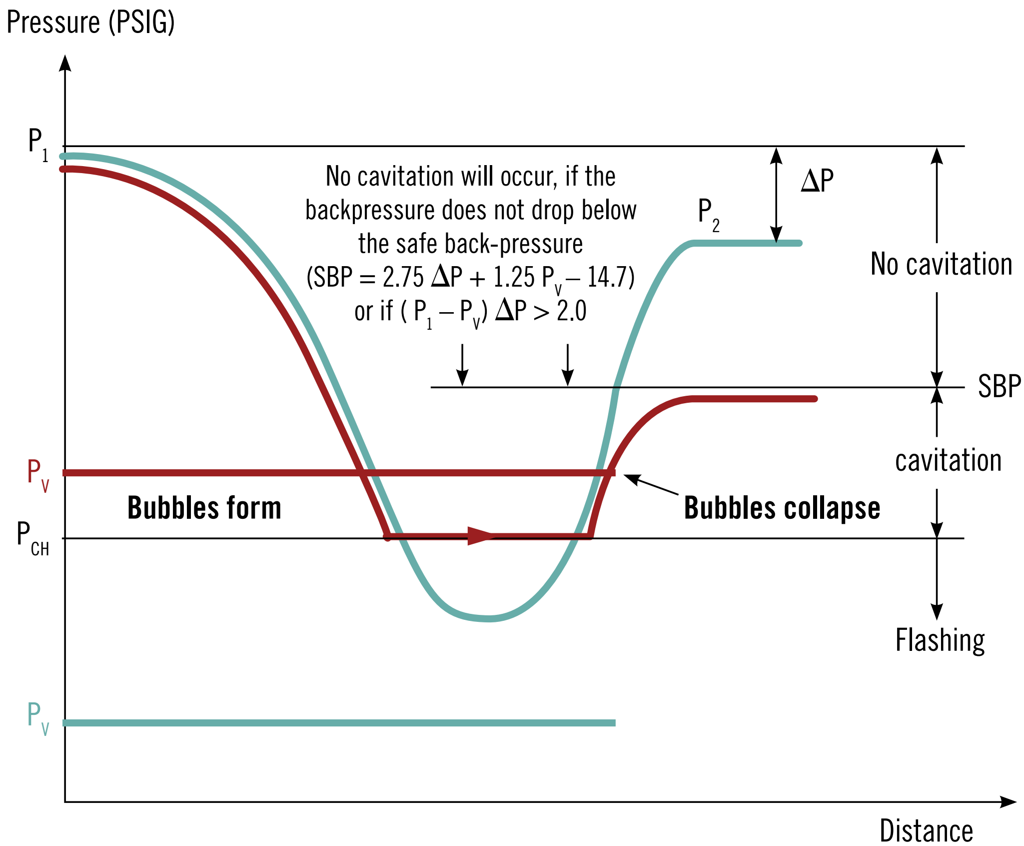
A1: Water hammer occurs when the flow of a water column is suddenly blocked and the momentum of that column is arrested. It can cause damage as it creates a pressure rise near the blockage. This can be caused by the sudden closure of a check valve, which can be corrected by replacing it with a slower-closing design. When water hammer occurs, you might hear bangs and the pipe might vibrate, but none of these occur because of using a vortex shedding flowmeter. In your case, what's likely happening is cavitation or flashing due to the high vapor pressure of the hot water.

Before addressing how to resolve your problem, let me first tell you how these flowmeters were discovered. A kid named Kármán Tódor was fishing in a spring in the beautiful Hungarian/Transylvanian countryside (today Romania). He noticed that in the water downstream of the rocks, swirls developed and traveled with equal distances between them. That distance remained the same, no matter the flow of water from the spring. So, little Tódor could



PRESSURE PROFILE THROUGH A VORTEX METER

Figure 1: Pressure profiles of hot (red) and cold (green) waters as they pass through a vortex meter. On cold water service, the pressure at the vena contracta doesn't drop down to the vapor pressure PV, but on hot water service it does. Therefore, the meter will cavitate and eventually choke (PCH) if the back pressure (P2) drops below the safe back pressure. At SBC, choking occurs, and if the back pressure (P2) drops further, flashing occurs.

measure the flow of water from the spring by counting the number of swirls passing by each minute.

Growing up, he became Theodore von Kármán, but this memory stayed with him, and helped him develop the JATO rocket motor as chief of NASA's Jet Propulsion Laboratory, and later become the father of space travel and the best-known aerodynamic theoretician of the 20th century. To me, his experience proves that we should live with our eyes open when we see complex symptoms—like climate change or the misuse of AI to collect ransom by shutting down pipelines—and always try to figure out "why is this happening?," just as little Tódor did when seeing those vortices.

Now let's look at your vortex flowmeters. In liquid flow, the total energy is constant, so when the kinetic energy (velocity) rises, static energy drops (pressure). In vortex meters, the maximum velocity occurs in the region of the bluff body, where the cross-sectional area is the minimum (the vena contracta or VC). Cavitation occurs when VC pressure drops below the vapor pressure (PV) because vaporization starts and vapor bubbles form at that point (Figure 1). This doesn't occur when flowing water is cold (green line) because PV is low, but it does occur with hot water (red line) if PV is higher than the pressure at the VC.

Downstream of the VC, the pressure recovers, and vapor bubbles violently condense. This collapse creates erosive micro-jets, noise (rumble, rattling or squeal), vibration and loss of measurement accuracy.

As vapor pressure rises, vaporization increases and causes the velocity at the VC to rise, until it reaches sonic velocity (Mach 1). As at that point, the flowing velocity can't increase further and "choking" occurs. The pressure corresponding to this condition is called the choking pressure (PCH). Under these conditions, if the downstream pressure (P2) drops further (or if the liquid temperature rises and PV increases), a region of supersonic flow forms just downstream of the throat of the flowmeter. This condition is called "flashing." The resulting vapor flow with water droplets in it accelerates as it moves away from the throat, and as the area of the diverging section increases, this supersonic acceleration is terminated by a shock wave and drops back to a subsonic condition. This shock wave can be mistaken for water hammering. Whichever it is (cavitation, choking or shock waves), the measurement becomes useless.

As to what to do, you can:
Use another type flowmeter.

Measure the flow where the temperature is lower.

Measure the flow where the pressure is higher by moving the meter upstream.
Increase the size of the meter.
Select a meter design having a lower pressure recovery factor.

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A2: I suspect you have cavitation in those meters. Water hammer is another thing.
At the point of pressure drop, the water is flashing into steam, and where the pressure rises again, the stream collapses back into water accompanied by high velocity water jets. These are very damaging and meter tube failure is possible. There is no simple or cheap solution. The meter is in the wrong place. Relocation to a position with higher pressure or lower temperature, or replacement with a larger meter with less pressure drop would help. Any water meter where the water is too close to boiling is trouble.

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"The cable tray with metallic barriers is designed to allow AC power wiring and DC signal wiring to share a common cable tray. All shields should be grounded only at one point to prevent ground loops."

Q: How much distance should separate 110 VAC alarm signal wiring (such as for a beacon) and a 4-20mA signal cable (class VI) in a tray with a metallic barrier? Same question for separation distance from a 24 VDC switch signal cable (Class I but with shield)? Finally, how much distance should separate the 110 VAC and 24 VDC signal wires described above in a tray but without a metallic barrier?

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A1: I assume that the "AC alarm" is a normally-open circuit, and therefore carries no current during normal conditions. If so, there are no minimum separation distances required, especially in a cable tray with a metallic barrier separating AC from DC signal lines.

The cable tray with metallic barriers is designed to allow AC power wiring and DC signal wiring to share a common cable tray. In such wiring, the DC cable is expected to be twisted-pair with a shield that's grounded at one end, or a multi-pair plenum cable with several shielded twisted-pair wires with an overall shield. All shields should be grounded only at one point (typically at the power supply) to prevent ground loops. The presence of the metallic barrier is sufficient to prevent AC interference with the DC signals. Twisted-pair cabling for DC signals is designed to allow a high degree of common-mode noise rejection by the receiving instrumentation.

Rest easy, the cable-tray specifications don't recommend separation distances because it doesn't matter. Noise rejection relies on shielding, the metallic barrier, and using twisted-pair wiring. In your case, the AC alarm circuit normally carries no current anyway.

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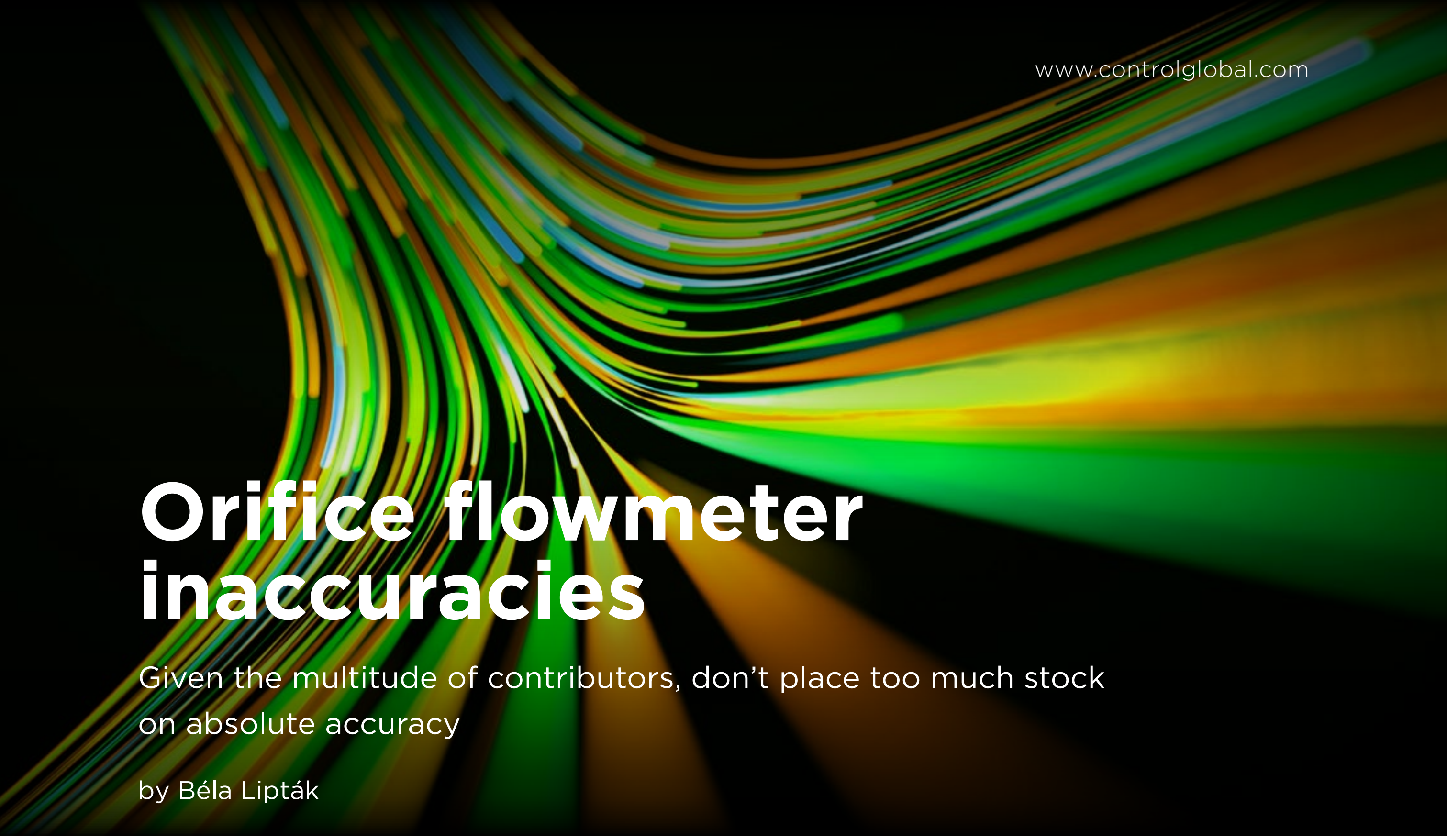
Running
98.0
l/min
Flow
23.1
°C
Temperature



Orifice flowmeter inaccuracies

Given the multitude of contributors, don't place too much stock on absolute accuracy

by Béla Lipták

Q: On the first page of section 2.15, "Orifices," of your Instrument Engineer's Handbook, Fourth Edition - Process Measurement and Analysis, Volume I, it's written that "if the bore diameter is correctly calculated, prepared and installed, the orifice can be accurate to ±0.25 to ±0.5% of actual flow."

My question is as follows: according to formula 3 of ISO 5167-1 and ignoring all other uncertainties except the discharge coefficient, C, the minimum uncertainty for mass flow rate is the same as the uncertainty of C. The latter, as per clause 5.3.3.1 of ISO 5167-1 is at minimum 0.5%.

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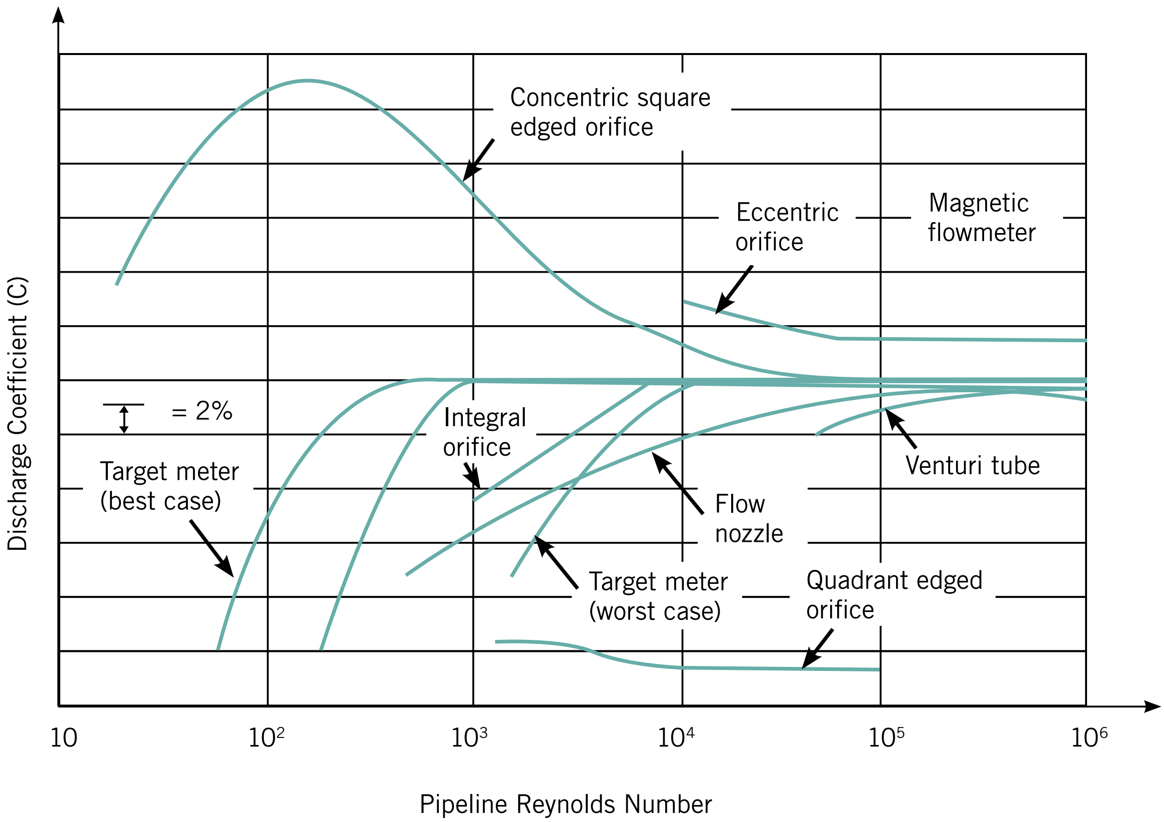
A1: A very useful question, because it shows that sometimes loop performance and component performance are confused. In the front of each chapter of my handbook, the key data for only the discussed component (in this case the orifice plate) is given, but not for the flow loop. Such key data includes uncertainity, which can also be called error or inaccuracy (but certainly not accuracy). The data for the orifice plate, as discussed in Chapter 2.15, is only for that component and assumes a calibrated plate.

This is probably also the case with the ISO statement because it assumes that ß, D, Re etc are accurately known constants and contribute zero error. With loop components, this is



FLOW COEFFICIENT VS. REYNOLDS NUMBER

Figure 1: For differential-pressure-generating flow elements, flow coefficents vary with the Reynolds number of the flow being measured.

quite common. For example, when ABB reports its Flow-X calculator uncertainty is 0.006%, it doesn't mean the flow measurement error will only be 0.006%. In short, my advice is to read not only the front summary, but the whole chapter in my handbook because the front page summary is only for the components discussed and can be misunderstood. Actually, in future editions, I might just leave out these summaries to avoid such misunderstandings.

Now, let me elaborate about the other potential error contributions to the total uncertainity of an orifice-type flow measurement. The volumetric flow, Q, through an orifice is:

Q = CA h/

The mass flow, W, is:

W = CA h

Where Q is volumetric flow, C is the discharge coefficient, A is the pipe cross-sectional area, h is the pressure drop across the orifice, and is the density. Now, let me mention potential error sources, which will add to the total uncertainty of the orifice-type flow measurement.

Density (): The uncertainty in density (or composition) measurement is usually high (particularly in natural gas measurement), and the resulting error is additional to that of the orifice error itself. The fact that density is under the square root when measuring the mass flow is advantageous because that reduces the increase in the flow measurement error. Errors will also occur if the pressure drop exceeds 0.25 of the inlet pressure because that creates excessive density changes as the flow passes through the orifice.

Discharge coefficient (C): The variation in C is the main contributor to the total flow measurement error because C changes are caused not only by ß ratio variations (ß ratio must stay within 0.2 and 0.65), but for many other reasons. For example, C changes as velocity profile changes due to Reynolds number variations. Figure 1 shows the relationships between discharge coefficient C and the Reynolds number for a number of head-type flow sensors, including concentric square edged, beveled, eccentric, integral and quadrant radius orifices.

C also changes if the location of the vena contracta varies, because it moves with the velocity of flow, and also because the downstream pressure tap is usually not at the vena contracta. Usually flange or corner taps are used in pipe sizes under 2-in., vena contracta taps are used for 6-in. or larger pipes, and pipe taps are used for sizes in between. In addition, as material builds up on the inner surface of the pipes or as corrosion or erosion reduces the sharpness of the orifice edges, the value of C also changes.
Recalibration, rangeability: Dual chamber orifice fittings allow orifice plate removal, replacement or insertion without interrupting the flow by changing orifice plates under pressure, so they eliminate unscheduled downtime. These dual-chamber devices can be operated oth manually or be motorized, and can reduce measurement unceratinty. They can change the flow rating (increase the rangeability) of the measurement by sliding a new plate into the flowing stream with a different ß ratio. Such fittings can also be used to replace orifices that have likewise lost the sharpness of their edges or can replace them with calibrated plates.

Transmitters: In addition to the above error sources, the measurement error of the developed pressure drop contributes further uncertainty to the flow measurement. Even newer smart transmitters with automatic span switching usually contribute about 0.1% full scale (FS) error, which being a fixed quantity, has to be multiplied by the rangebility to determine the % actual reading (AR) error at minimum flow.
The bottom line is that even newly calibrated plates with state-of-the-art transmitters

will have 1% or so uncertainty; the error of an uncalibrated orifce with an analog transmitters will be no better than 2% and will grow worse over time.

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A2: Regarding the question of orifice plate accuracy (I hate that word), it simply can't be better than the overall uncertainties of the individual components. As a starting point, the uncertainty of the discharge coefficient has to be added to the uncertainty of the measuring system, i.e. the differential pressure cell used to turn the indicated differential pressure into a flowrate. This takes the minimum uncertainty well above that stated in the Instrument Engineers' Handbook. I have to say the statement it's made is misleading in the extreme. The methodology outlined in ISO 5167-1 should be followed, and all the influential effects have to be considered.

In my experience over 40 years, I haven't found an installed orifice plate to be better than 1% even when new. The edge sharpness and pipe internal roughness change with time, and I've done independent audits on older orifice plates and found in some instances the overall uncertainty to be greater than 5%. I hope this helps answer your concern.

Dr. Richard Furness
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A3: Perhaps you've discovered a misstatement in the Instrument Engineers' Handbook. Also, an orifice flowmeter doesn't measure mass flow, only volumetric flow. Perhaps the statement in the ISO 5167 standard relating to mass flow is inaccurate. Second, who cares? Using an orifice flowmeter for accurate flow measurement is foolhardy. An orifice flowmeter will never be accurate, and will become less accurate over time as the sharp edge of the orifice wears. Using flange-taps is common, but the downstream flange tap is never at the location of the vena contracta, even though an orifice measurement depends on the downstream tap being located precisely at the vena contracta.

If accuracy is needed, use a positive displacement, turbine or Coriolis flowmeter. Orifice flowmeters are most often applied in flow control where accuracy isn't required, but repeatability is important.

Dick Caro
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A4: Possibly the ± 0.25% refers to a calibrated orifice.

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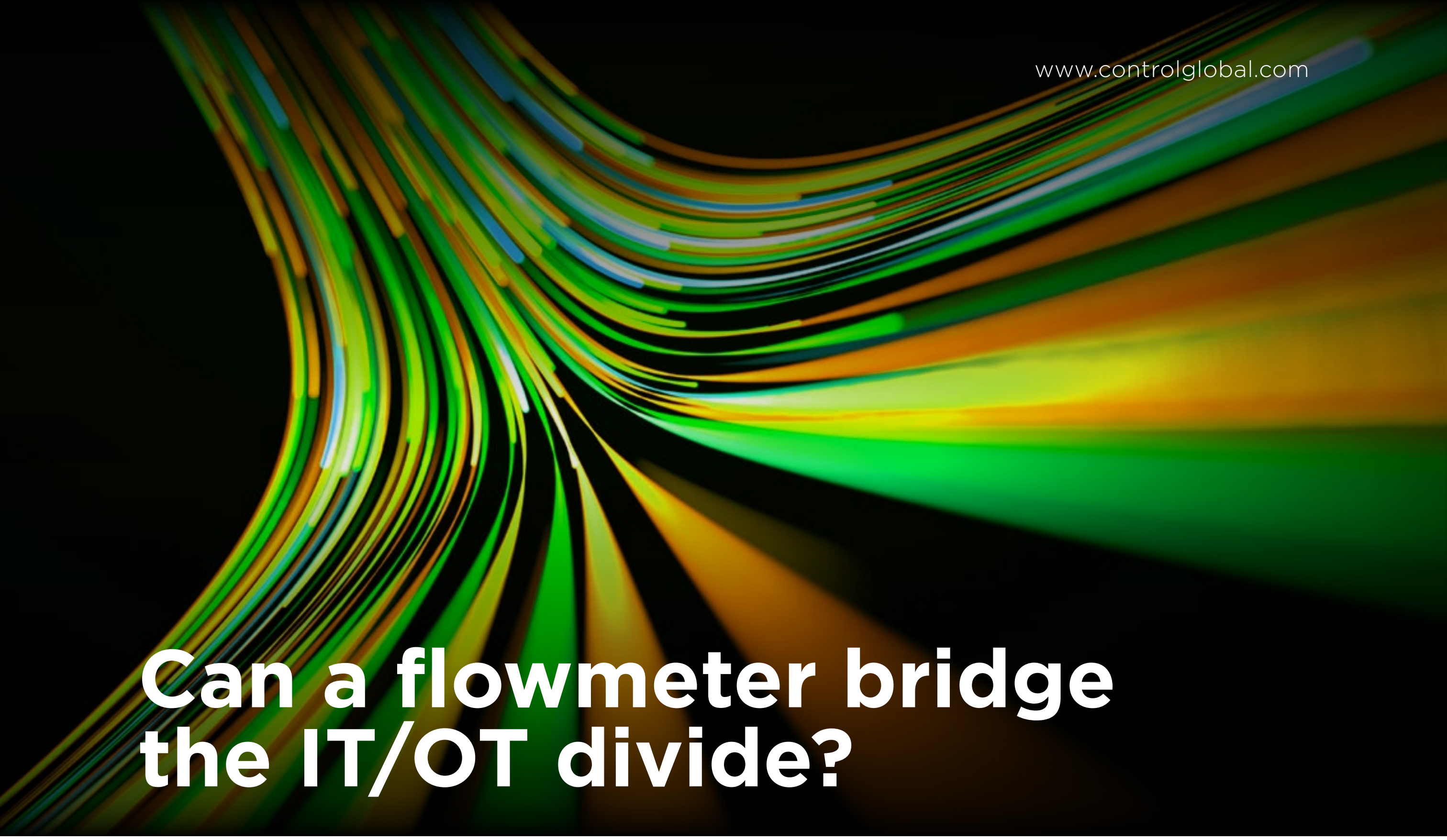

Can a flowmeter bridge the IT/OT divide?

If marketplace adoption is the primary judge, then the process industry's first-generation digital fieldbus standards significantly underachieved. Indeed, the venerable 4-20mA analog standard, augmented by HART, remains the predominant field communications modality. Sure, process variable updates are nearly instantaneous, but transmission of all that other data that our IIoT applications crave is slow as dirt relative to current-day expectations.

But what if one instrument could preserve the stodgy but dependable operational technology (OT) connectivity we're all used to, while also plugging into the speedy new IT networking standards that will finally deliver us to Industry 4.0? ABB had some ideas, and those concepts are now embodied in the company's latest generation of CoriolisMaster and ProcessMaster (magnetic) flowmeters. Control recently caught up with Vanessa Klekar, U.S. technical sales specialist manager for ABB Measurement & Analytics, to discuss how these instruments can provide a future-proofed bridge from yesterday's expectations to tomorrow's.

"You don't have to choose one or the other, instead you can have either or both. This means you can connect your flowmeter's analog output to an existing DCS I/O module and use your Ethernet connection for secure, speedy access to all that other data."

Q: These new Coriolis and magnetic flowmeters represent some true industry firsts. Can you tell us more about what makes them unique?

A: At ABB, we appreciate that most flowmeters being purchased today will go into brownfield sites, and it's going to be some years before a greenfield facility will be based exclusively on Ethernet from the ground up.

So, our new meters come equipped with both 4-20mA analog connectivity, as well as a plug-in Ethernet board. You don't have to choose one or the other, instead you can have either or both. This means you can connect your flowmeter's analog output signal to an existing DCS I/O module, and use your Ethernet connection for speedy, secure access to all that other data. And when you're ready to do control via the Ethernet connection, you can do that, too. We even offer the option of retrofitting existing ABB FEP630, FEW630 and FCB400 meters to bring Ethernet connectivity to our global installed base.

Further, there are two available versions of the plug-in Ethernet board. The four-wire version includes an integrated, two-port Ethernet switch, so that all topologies—ring, star and daisy chain—are supported. Or, the two ports can allow redundant network communications. Significantly, the ABB approach provides an option to draw its power from the Ethernet loop (Power over Ethernet, or PoE). They're the first flowmeters of their kind to offer a PoE option. We also created a more rugged alternative to the standard RJ45 connector used by most suppliers that's vibration resistant and doesn't require any special tools.

Q: PoE is particularly appealing because, like 4-20mA, it obviates the need for separate power wiring. What other benefits does it offer?

A: First, it's simple. It uses standard Ethernet cables like a typical network and a centralized power supply unit that satisfies all device requirements. Second, it's flexible. With remote and centralized power, the instrument can be installed wherever needed, regardless of any power supply in range. It can also easily extend to the nearest Ethernet switch or be boosted to an existing network by using a midspan PSE (power sourcing equipment) if need be. Another advantage of PoE is it can cut costs by taking advantage of off-the-shelf components—even those designed for office environments where appropriate. And, since it needs only one standard Ethernet cable, it can cut installation efforts in half. Finally, by leveraging a standard, centralized uninterruptible power supply, it can boost overall system reliability and be remotely powered down during periods of low usage or for security or safety reasons.

Q: Ethernet really only describes the physical network layer—what protocols are available in the new meters?

A: One of the great things about Ethernet is that most of the automation industry's go-to protocols were either created for Ethernet or have been brought over to that physical network layer, and more than one can run on the same network at the same time.

ABB has added Ethernet connectivity to its CoriolisMaster (pictured) and ProcessMaster electromagnetic flowmeters, while preserving the devices' 4-20mA analog output.

Currently, EtherNet/IP is supported for deterministic use cases such as control loops and cyclic communication of process values. Modbus TCP is another option for communication with remote terminal units (RTUs) and flow computers. Also in the works are support for Profinet and OPC UA, which promises to enable a broad new range of automation solutions and unprecedented ease of integration and communication.

The flowmeters can also speak the secure language of the web, HTTPS, and like all ABB products, they've undergone extensive vulnerability testing at the ABB Digital Security Assessment Center before release. The meters' integrated webservers are based on the ABB Ability Cyber Security framework, ensuring robust and secure support during instrument commissioning and troubleshooting. They also boot securely, with each flowmeter featuring a public/private keypair for integrity protection of its firmware. The ability to remotely deliver firmware updates will also debut soon.

The integrated webserver also generates QR codes to facilitate access to configuration, diagnostics and measurement data. It also allows remote verification of all parts of the flowmeter, and provides insights into its operating condition with automatically generated reports through our SRV500 measurement verification software.

Q: What other future developments will the addition of Ethernet to your instrumentation platform make possible?

A: With the addition of Ethernet connectivity, we're future-proofing our instruments and paving the way for continued convergence of IT and OT technologies. This includes the potential use of non-industrial protocols such as video, audio and VOIP on the plant-floor, as well as emerging developments with implications for the process automation such as time-synchronized networking (TSN) and network traffic orchestration. And while it's hard to predict the new use cases we'll be exploring five or 10 years from now, it's a safe bet that Ethernet will be at their foundation.