Tackling Pipeline Contamination

OGI sits down with Paul Stockwell, Managing Director, Process Vision Ltd, to find out more about contamination in gas and the importance of reliable and accurate monitoring. Mr. Stockwell wants to help readers understand the importance of having an alarm system to notify users before it's too late and the contamination is in the system, which can cause a potentially dangerous and costly event.

OGI: Could you start by explaining Process Vision's credentials and experience in terms of your products and services for the oil and gas sector? Could you tell our readers the breadth of your experience, how long the company has been active, and its reach?

Stockwell: Most of my career has been spent with instrumentation for oil and gas companies. Mainly with dewpoint, H2S measurement and gas chromatography systems. I started International Moisture Analysers (IMA) in 1995. A lot of our equipment is installed at custody transfer points for gas networks. One of the networks highlighted that, despite all the gas analysers, liquid carry-over did not trigger an alarm. After some research, we de-merged Process Vision in 2016 to concentrate on solving this problem. It's been a fascinating journey; the joy and the pain is that nobody else is doing what we do. We discovered that the real world is very different from CFD modelling and high-pressure test loops. We are still learning something new every time we install a contamination detection system.

OGI: Could you talk a bit about natural gas monitoring and why it's so important?

Stockwell: It's down to both safety and cost. We believe it is better to have an alarm system to prevent contamination from entering the network, rather than cope with a contamination event. This is for good safety reasons, the agreements between the gas network and the gas supplier stipulates maximum values of various parameters such as water vapour and H2S. It also requires that no liquids are supplied to a gas network. While gas quality is monitored to ensure it complies with the entry requirements, very often the first time the network knows of a contamination event is when a gas turbine power station is damaged, or a compressor explodes due to liquids.

There was a pipeline rupture in New Mexico a few years ago due to liquid carry-over causing internal corrosion at a low spot in the network. Liquid pools at a low spot in the network and accumulate to a point until it is sufficient to cause a slugged flow that moves rapidly and over-runs filter systems ahead of compressors and other plant and can be very dangerous to be around. If that wasn't bad enough, contamination within the pipeline breaches the electrically insulating joints between underground and overground pipework sections. This causes failures of the cathodic protection systems that reduce corrosion on underground pipework.

Besides safety, flow metering errors caused

Paul Stockwell, Managing Director, Process Vision Ltd

by tiny amounts of contamination (2-3mm) in a pipeline cause flow meters to over-read that, on an average size system would be about $0.5M a year.

In every other walk of life the polluter pays for the cleanup but, with pipeline contamination, it's down to the gas network. Nobody knows which of the gas suppliers had the failure or is continuously allowing liquids through.

OGI: What are the different methods available for monitoring gas?

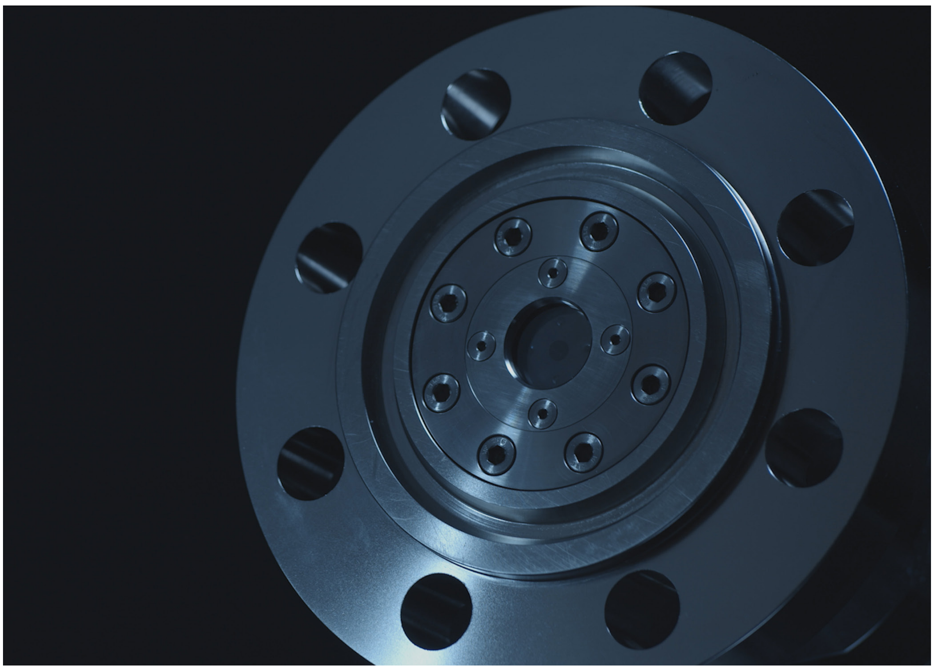
Stockwell: Many different techniques are used depending upon which parameter is being monitored. Gas chromatography and spectroscopy are widely used to determine many of the parameters. Dewpoint meters for both water vapour and hydrocarbon (HC) are also common. However, these all sampled from the pipeline with the analyser some distance away. All metering guidelines recommend sampling from the middle of the pipeline to avoid contamination travelling on the pipe wall. So, in the case of HC Dewpoint, the measured value (or the calculated from the gas chromatograph) is based only on the gas phase element of the pipeline. If heavy HC liquids are traveling along the bottom of the pipeline, these are not included in the calculation.

There are particle analysis system that can be installed for a survey or temporarily but, again they sample from the pipeline and only look at the liquid entrained in the gas flow.

By looking directly into the pipeline, we can capture the complete pipeline activity.

OGI: What are the benefits for engineers by being able to make better and more informed decisions?

Stockwell: LineVu can be used to diagnose what the high (or low) flow limits are on a separator. This will vary depending on the



LineVu Unit: Image Processing Reports Contamination Events.

amount of fouling and temperature, so finding the maximum flow rate possible before the liquid breakthrough can make a big difference to productivity.

As an engineer, it is always better to make evidence-based decisions. Particularly with safety issues or when the repercussions of that decision result in high financial losses. Being a camera-based system, engineers can have a live video feed of what's happening in the high-pressure pipeline or process. This leads to a better understanding of real-world conditions, particularly useful at start-up, shutdown or flow ramping conditions. Providing operators with this insight allows them to makes sense of the numbers that they see on the DCS or SCADA system.

In many systems, it is the separator that limits the throughput of a gas treatment system. The visual feedback from a live video stream can allow operators to establish the maximum flow availability before liquids start to breakthrough.

OGI: What is LineVu and its applications?

Stockwell: LineVu is a camera system usually mounted on top of a gas pipeline on a standard tapping point. The camera and illumination system look through an isolation valve to the pipeline below. In theory, most of the time, there is just gas moving through the pipe, so we use image processing to create an alarm when contamination is seen. The system records all activity for later playback for investigations. Local operators can get into the system to see a live or historical video and a SIM card allows authorised users to connect via a mobile phone or tablet. Operators are alerted by a relay operation, and they can be alerted via text or email when the alarm activates.

One of the big surprises for us was just how slow some of the contamination moves, so we use a lot of time-lapse videos to show movement.

OGI: There are exciting new prospects in monitoring on the horizon, such as technology that would enable the user to inspect inside the pipe, from the outside, are you able to discuss more about that?

Stockwell: We have spent the last two years developing a small diameter snake robot that can enter a pipeline or vessel while at high pressure. This is a big step in technology and will allow us to have a more detailed inspection without shutting the system down. As it is always tethered to the outside world, it has a material extraction system that allows removal of a sample or to remove fouling. We have just completed the proof of concept and have a working system.

We are now beginning to engage with industry to find applications. The first one we are looking at is the possibility of cleaning tube and shell heat exchangers (HE) without the need for shutdown. Fouling in HEs is such a big problem, it is estimated to be around 0.28% of GNP. If we can keep these systems online while maintaining their efficiency at a high level, we hope to make a significant impact not to just to oil & gas but to all industries that use Tube & shell HEs.

OGI: Finally, could you enlighten our readers of a case study where you helped a client with your solutions?

Stockwell: We are working with a number of gas networks in Europe, the Middle East and North America, and we always respect client confidentiality. Videos of contamination events from systems deployed at entry points to gas transmission systems on our website. We have produced an excel spreadsheet that mimics a flow meters systems and calculates the impact of a small amount of solid material deposited on the walls of a flow station has. Once you start looking into the flow assurance errors, its amazing what effect the contamination we have seen in the real world has on uncertainty on flowmeters used for fiscal purposes.

OGI: Thank you for your time. •

If you would like to know more about how Process Vision Ltd can help your company and its operations, please contact them at:

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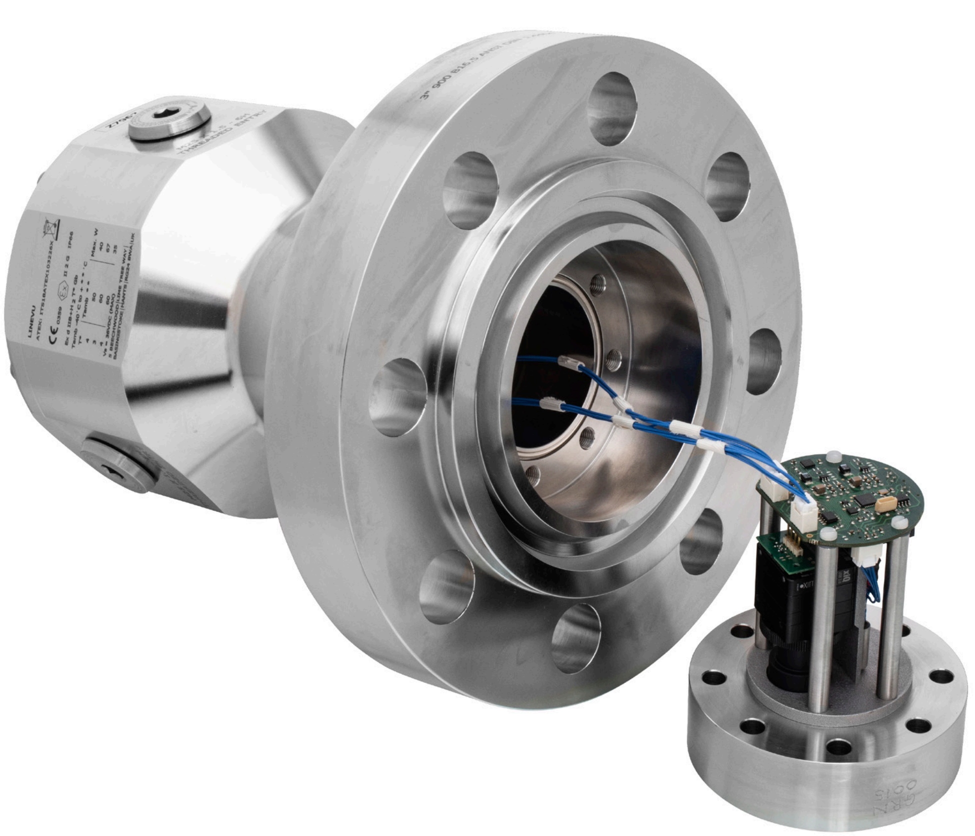

A patented secondary containment system ensures no loss of containment, even under fault conditions.