Technology and Business Information for the Global Gas Processing and LNG Industries

GAS PROCESSING & LNG

GasProcessingNews.com | MAY/JUNE 2024

OPTIMIZING PLANT/PIPELINE OPERATIONS

FOR INCREASED SAFETY, PROFITABILITY

REVEALING UNSEEN LIQUIDS in gas pipelines

How to protect **LNG PROCESSES**

Global pipelines construction **OUTLOOK**

MAINTENANCE, RELIABILITY AND INSPECTION

Innovations in monitoring: Revealing unseen liquids in gas pipelines

P. STOCKWELL, Process Vision Ltd., Basingstoke, UK

All dry gas flows can unpredictably become wet, and accidental liquids in gas transmission networks create hidden financial costs and pose serious safety risks. With many pipelines monitored with a process camera[a] to date proving to have wet gas, it is not surprising that liquefied natural gas (LNG) plants and gas turbine power stations have frequent unscheduled outages due to liquid carryover of glycol and compressor oil. Good phase separation at both the front and back ends of gas processing is vital to ensure an efficient process and can provide an easy win to boost production, reduce maintenance and improve safety.

Liquid carryover is the primary cause of failures in gas processing, causing loss of production through foaming or the risk of foaming, fouling, and the use of extra chemicals to de-foam and chemical scavengers to remove impurities.

Observations using a new process camera system[a] have shown that, unless phase separation is performed at a high level at low temperature, it is common for sales-quality gas to be transported as a wet gas, despite dewpoint systems indicating that a dry gas is present. In addition, the carryover of glycol from dehydration systems is common; however, this is not a parameter that is monitored at the custody transfer point.

For the first time, engineers can view inside a live pipeline and observe that when these "dry gas" systems are monitored, mist or stratified flows are often detected, sometimes with high levels of contamination. With this monitoring in place, the performance of different gas processing trains within a gas treatment plant can be balanced to minimize carryover, and differences can be investigated.

With gas sampling systems that comply with American Petroleum Institute (API) standards, liquids in gas flows are removed to provide the gas analyzer systems with a representative gas sample. Therefore, with liquid carryover events and failures in phase separation systems going unnoticed and unreported, the industry is running blind. Innovative process camera systems[a] can demonstrate how unseen liquids can slip past gas analysis systems undetected and leave operators unaware of problems until it is too late.

When installed at the inlet of a gas processing plant, these systems[a] can improve phase separation, reduce the threat of foaming and the cost of operations, and increase flowrates when operational conditions allow. When installed at the export line of a gas processing plant, gas sampling systems ensure that liquid phase condensate—not monitored by gas chromatography (GC)—does not enter the gas line. The system[a] also allows transmission system operators (TSOs) to ensure tariffs are not broken and reduce the threat of compressor failure and corrosion occurring under liquids pooling at low points in the gas transmission system.

Process cameras. The impact of wet gas and liquids on dry gas flow measurement and gas analysis is significant. Using process cameras capable of imaging high-pressure gas pipelines and systems allows operators a live view of what is really happening in the pipeline. Providing experienced process engineers with live-streaming video provides real-time feedback and often produces data that questions the status quo.

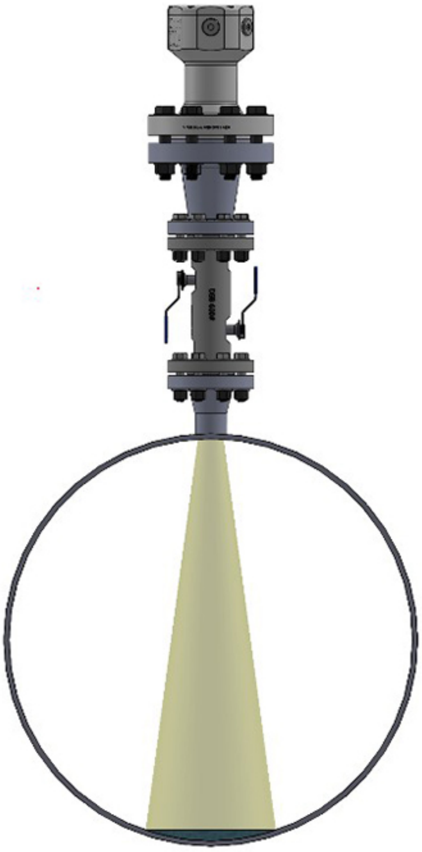

FIG. 1. A process camera[a] mounted on a gas pipeline.

The process camera[a] is normally mounted vertically on a pipeline and provides views of the pipeline floor by illuminating and imaging through an isolation valve (**FIG. 1**). This setup allows easy installation by using existing tapping points. The images from the camera are a plan view of the pipeline floor. Liquid streams, solids and mist flows can be observed. Aerosols (liquids and solids) travel at the gas velocity, while stratified flows have lost most of their kinetic energy and, in large-diameter pipelines, travel at the bottom of the pipe. When live streamed to the control room, the camera[a] can often detect liquid streams while no other alarms have been activated. The metadata of the image [e.g., the brightness returned to the camera (or the variation of brightness)] is a useful parameter to show the stability of the gas flow and can be used as an alarm threshold. Using machine-learning provides an automated alarm with a deeper understanding and categorization of the severity of the incident.

Liquid carryover in gas processing. The live-streamed video and the associated data are proving to be useful new metrics to control gas processing plants, providing engineers with a better understanding of what is happening at the outlet of a phase separation system and other parts of the gas treatment process.

Crude oil, condensate, water and sand are usually present in feed gas from a gas well. Further liquids are added, with hydrate mitigation, corrosion inhibitors and bactericides being common additives. At this stage, a mixed-phase flow is intentional, but these factors add to the liquid loading of the gas entering the front-end phase separation at the gas treatment plant. Where there is compression between the gas wells and gas processing plant, compressor oil can be added to the possible contaminants as the gas enters the plant.

Ideally, only gas enters the gas processing. A detailed survey by Amine Experts indicates that the efficiency of the front-end phase separation is vital.[1] A survey within the study includes 400 amine plant failure cases, with each case costing the operator between $250,000 and $250 MM.

The survey concludes three main causes of failure:

- Corrosion due to poor amine quality
- Foaming due to contaminated gas at the inlet
- Product quality due to insufficient heat.

Two out of the three causes of plant failure (poor amine quality, contaminated gas at the inlet) highlight the need for better filtration and phase separation at the gas entry to processing plants. The results of the survey (**FIG. 2**) show the causes of foaming.

Four factors (highlighted in the box in **FIG. 2**) are caused by contamination of the inlet gas, indicating that incorrect phase separation is the primary cause (61%) of foaming events. With improved knowledge and understanding of the condition of the gas at this stage of the process, immediate action can be taken to add de-foamer early and avoid a major foaming event rather than cutting the gas flow to get foaming under control. De-bottlenecking studies can provide clarity of when (and how) breakthrough occurs, as well as how to implement better maintenance practices on demister pads, justify the cost of improving the phase separation (if required) and prove that the solution worked.

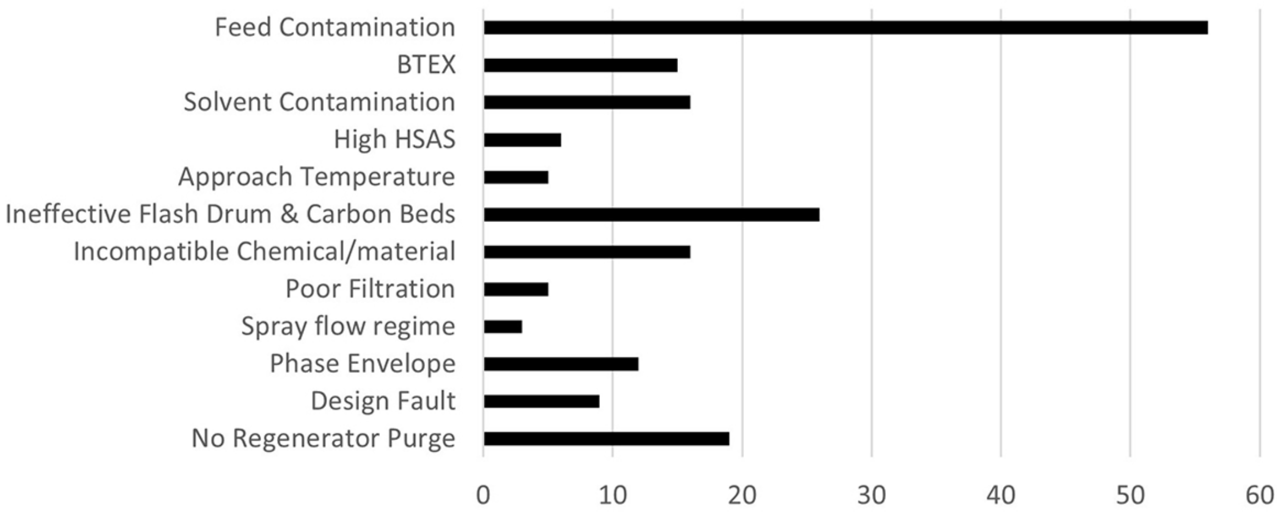

FIG. 2. The main causes of foaming in a gas processing plant.[1]

Because foaming is a major risk, many gas plants limit gas flow and run under the optimum flowrate to provide a "margin" in case of foaming. The greater confidence that a process camera[a] provides allows operators to run a little closer to the optimum knowing they can react quickly if a liquid event occurs.

As the gas moves through de-sulfuration and de-humidification, large quantities of liquid come into contact with the gas. If not separated, liquid carryover will contaminate the next stage of the process:

natural gas liquids (NGL) removal. Once the gas is sweet and dry, the usual method of extracting as much NGL as possible is to reduce the temperature of the gas, forcing the gas below its hydrocarbon (HC) dewpoint and separating the liquids. Temperature reduction is normally achieved by Joule-Thompson pressure reduction in turbo expanders. However, this creates the right environment, on a flowing gas, to produce a sub-micron mist flow—the most difficult type of liquid to filter out. While the correct temperature is achieved, unless high-level filtration is used while the gas is at low temperature, liquid removal is not sufficiently effective. The gas processor suffers the cost of the temperature reduction but not the full benefit of NGL removal.

When pipelines are pigged, one of the frequent components removed is glycol. For glycol to be present in gas pipelines, it must pass through two-phase separators; it is unlikely that glycol would pass through the phase separator during NGL recovery without also allowing NGL (a less dense liquid) to pass through. In these cases, operators do not achieve the full financial benefit of NGL recovery yet still face the expense of reducing the temperature of large volumes of gas.

Errors in fiscal measurements: Calorific value. API, International Organization for Standardization (ISO) and Gas Processors Association (GPA) standards require that stabbing probes or quills be used to remove the gas samples from the middle of the pipeline to avoid any contamination on the pipe wall. The sample system must provide a representative gas sample to the analyzer where any liquids present in the pipeline (glycol, amine, NGL) are not included in the sample to GC and other gas analyzers.

When liquid onset begins, as seen in **FIG. 3,** a stratified liquid flow across the full field of view can be seen. The graph of both water and HC dewpoint shows no response from either analyzer system at the onset of the liquid flow event. It was assumed, therefore, that the liquids must be glycol. However, when the gas flow was stopped, the pipeline de-pressurized and, purged with nitrogen before introducing air, the liquid evaporated over 24 hr. As the liquid was volatile, it rules out glycol [mono ethylene glycol (MEG) and triethylene glycol (TEG)] and compressor oil, leaving only NGL as a possible suspect.

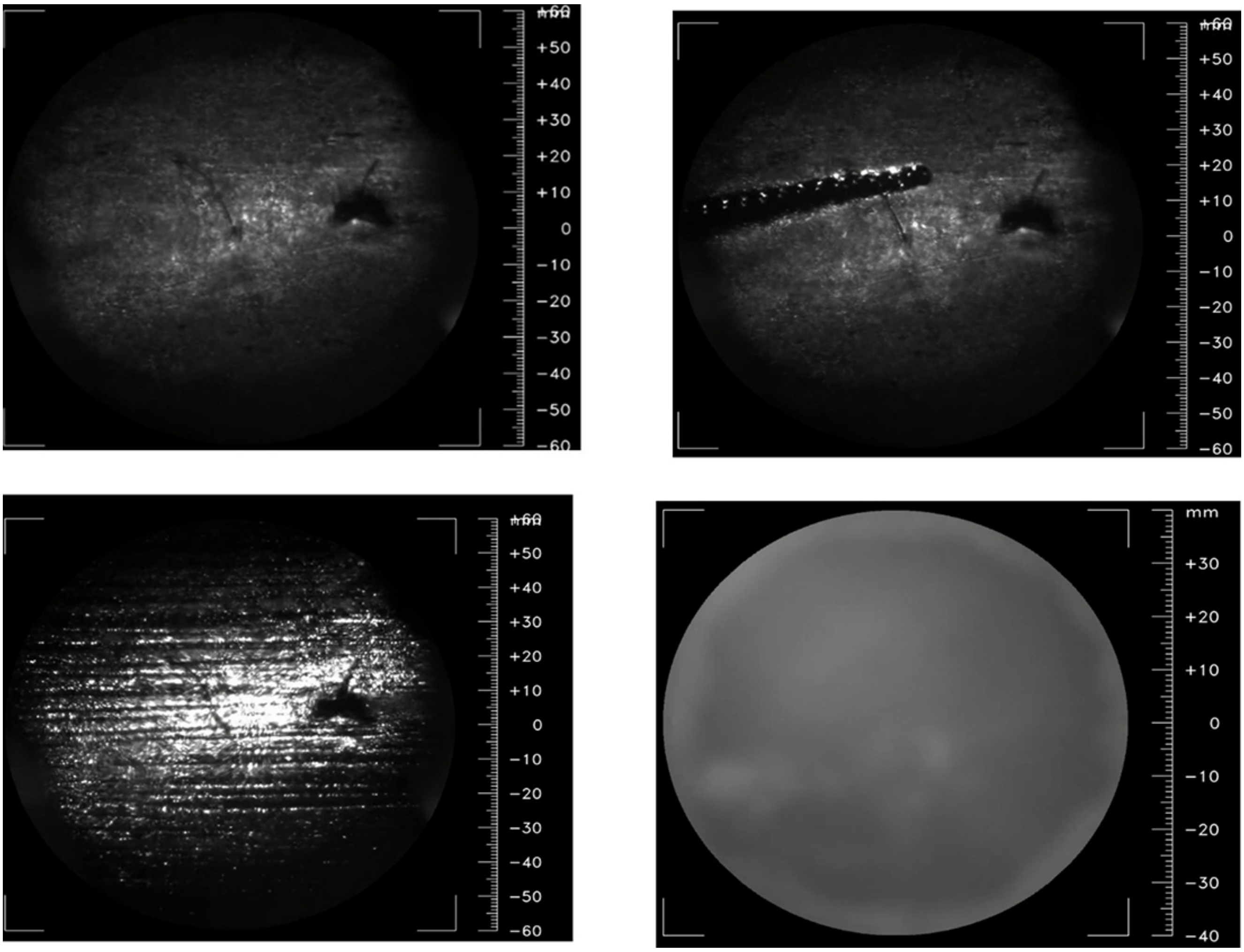

FIG. 3. The stratified flow of NGL on the floor of a pipeline and dewpoint trace indicating no change at the onset of the contamination event.

As described above, gas analyzer sample systems are designed to avoid and remove any liquids. While this is good practice for the long-term service of gas analyzers, it leaves operators unaware that these large-scale liquid events are happening. In addition, calculating HC dewpoint from GC data can also produce a false sense of security—in many cases, measured HC dewpoint is much wetter than calculated HC dewpoint.

Obtaining a true picture of the calorific value of the fluid stream in wet gas flows is complex. Even with iso-kinetic sampling operating at high temperatures, stratified flows will still not be included, and liquids in the mist flow coalesce on the sample pipework, causing large spikes. Gas analyzers can only report on the portion of fluid they are presented with. Presently, this means that:

- Measurements made at custody transfer points are wildly in error when a wet gas flow is present
- Operators are unaware when mixed-phase flow is present.

The installation of a process camera[a] validates gas analyzer measurements and alerts operators when a wet gas or mixed-phase flow is present.

Flow measurements and calorific value [British thermal units (Btu)] are both compromised when a wet gas is present. The situation is exacerbated as, to ensure reliable service on gas analyzers, sample systems for gas analyzers filter out liquids, so HCs that remain in the liquid phase are not included. Btu measurements are under-reported and HC dewpoint calculations are in error.

It has also been observed that in high mist flow conditions, the membrane filter in the analyzer sample system can "flood". In these conditions, the whole surface of the membrane filter is coated in liquid which then extrudes through the membrane. These liquids then vaporize in the heated sample system with the end result being the Btu reported is from the liquid phase only and can be 30 Btu–40 Btu higher than the gas phase. It has been shown across many installations that it is not possible for operators to know if the gas flow contains liquids until a process camera is fitted. When there is a wet gas flow present, compliance with API 14.1[2] cannot be assured and the Btu measurements cannot be relied upon.

Note: It is only by knowing the actual phases within the pipe, and their flow regimes, that the uncertainty of Btu and flow measurements can be reduced to acceptable levels. The Sarbanes Oxley bill[3] indicates that due diligence should be performed on all fiscal measurements.

Compressor damage. A survey performed by the Health and Safety Executive in the UK[4] examined 71 natural gas compressor failures. Each failure cost $60,000–$120,000 in addition to the loss of production. Compressor manufacturers and users were asked what the design life requirements are of dry gas seals. Actual life was determined by the survey:

- Design life requirements (manufacturers and users): 5 yr
- Survey results: 385 d (average).

The survey found that the main cause of failures was contaminated gas, where 100% of the failures showed liquids were found between the faces of the seal.

Examples of contaminated gas flows. The four images in **FIG. 3** show clean gas, stratified flow and mist flow. Features on the pipe floor can provide points of reference. **Note:** The still shots do not convey as much information as the videos from which they are taken.

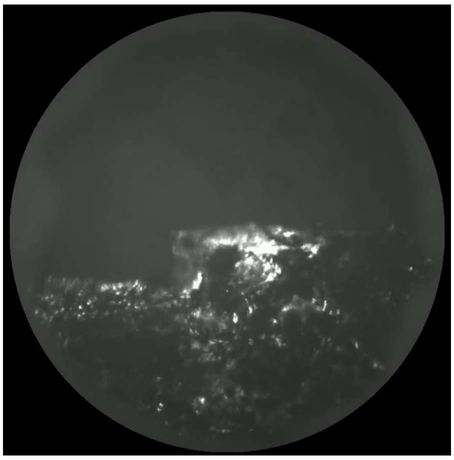

FIG. 4. Dry gas (top left); stratified flow of compressor oil (top right); stratified flow of condensate (bottom left); and mist flow (bottom right).

The images in **FIG. 4** show gas flow in real-world installations in a 36-in. (0.91-m) pipeline with various contamination flows. The gas pressure was 920 psi (63.4 bar), and the gas flow velocity was ~15 ft/sec (~4.6 m/sec). The top left image shows dry gas flow; the top right is a stratified flow of compressor oil with a surprising worm-like shape; the bottom left is a stratified flow of condensate in many small streams; and the bottom right shows a severe mist flow where the pipeline features are completely obscured by the mist. Stratified flow and mist flow can occur independently and simultaneously.

Computational fluid dynamic (CFD) models would indicate that stratified flows occur at low gas velocities and mist flows occur at high velocities. However, observations of stratified flows have occurred at both low and high velocities, and mist flow has been observed at both high and very low—and even stationery—gas flows. Numerous parameters affect the way contamination moves in a mixed-phase flow in large-diameter pipelines [e.g., a mist flow in a 100-mi (161-km) pipeline can turn into a stratified flow if there is a momentary drop in gas flowrate].

Gas flowrate, gas pressure, temperature, liquid density, liquid viscosity, pipe surface roughness, bends and flange joints are all contributing factors. It is common to see mist and stratified flows at the same location on different occasions or at the same time.

When mist flow is present, it is common to observe diurnal (time of day) changes. It is believed that the presence of repeatable diurnal changes indicates that a volatile gas component, most likely NGL, is present.

FIG. 5 shows grease-like contamination that, once gas flow was initiated, developed small liquid flow streams on its surface. Rapid gas flow across the top of slurries and grease-like material draws off the lighter end liquids. Over a period of a few weeks, this material becomes much drier, which explains the mechanisms behind dry material being removed when lines are pigged. With stratified flows, liquids slowly move down the pipe due to friction with the gas. These events contain solid material. As the liquid is moving, the quicker-moving gas above progressively dries out the liquid, leaving denser liquids and a higher solid content to a point where the contaminant is sufficiently dense and viscous to slow and then stop. It then continues to dry as stationery material on the pipe floor.

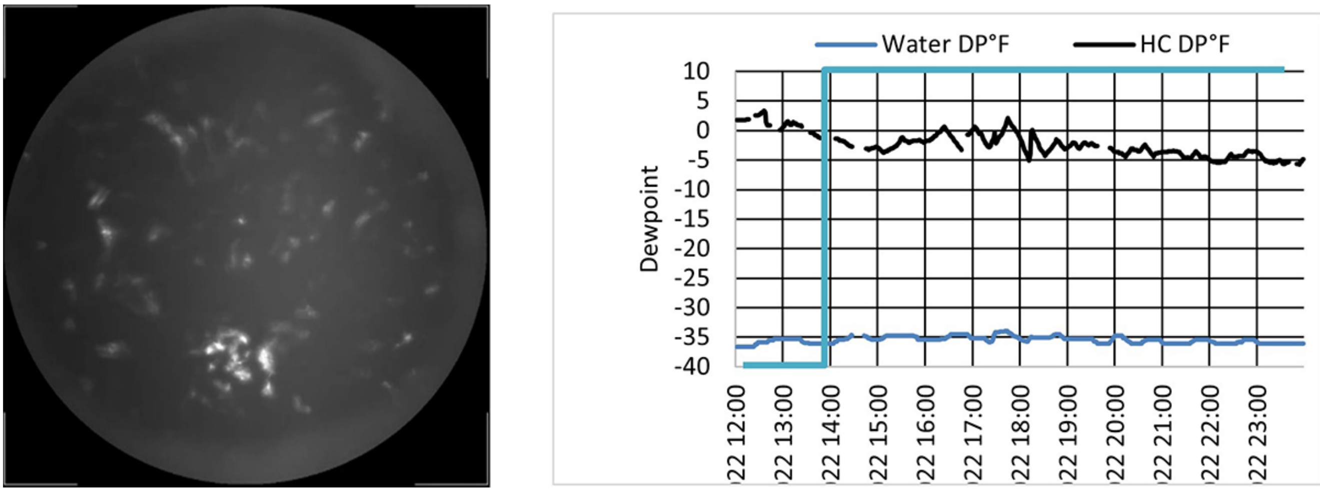

FIG. 5. Grease-like contamination.

Pipeline corrosion. Internal liquid hold-up in pipelines creates an additional risk of corrosion that can lead to pipeline rupture. Monitoring pipelines for liquid carry-over lets operators know if mist or stratified flows are occurring.

Underground pipelines are usually protected from external corrosion using cathodic protection (CP) systems. A small DC voltage is set up between the underground pipe and a sacrificial anode, thereby protecting the pipe section from corrosion when pipeline coatings and coverings are breached. To function properly, an isolating flange joint is inserted between underground pipe and over-ground pipe sections.

However, when solid material is conveyed along the pipeline, it breaches the isolating joint and, being electrically conductive, compromises the CP system.

Increased risk to power stations. By the time the gas reaches the power station, several factors increase the likelihood of contamination:

- Trace glycol and NGL in the gas at the inlet to the transmission system
- Lubrication grease from valve operations
- Compressor oil leaking into the gas
- Iron sulfides collected from the pipe wall
- Scale collected from build-up at valves and pressure reduction stations.

These factors contribute to contaminated gas reaching the power station and causing maintenance issues:

- Stratified flow causes uneven combustion around the turbine, putting high stresses on the turbine
- The blockage of fuel nozzles
- High wear on fuel nozzles
- Hot spots on turbine blades, causing some turbine blade holes.

Some power stations will heat the gas to 300°F (150°C), which should vaporize low-level NGL if they are present but do not vaporize glycol or compressor oil. It should also be noted that this heat is not available at startup, and flow starts/flow ramps are where the majority of stratified flows have been observed, leaving power stations vulnerable to liquid events and flowmeter errors due to high levels of liquid and solid material in the flowmeter lines.

Takeaways. Process cameras[a] can be used to great effect as a cost-effective method to increase production in gas plants, improve NGL recovery, decrease calorific value and flowmeter errors, reduce pigging and disposal costs for TSOs, and lower compressor servicing costs. **GP&LNG**

NOTES

[a] Process Vision Ltd.'s LineVu

LITERATURE CITED

1. Le Grange, P., B. Spooner and M. Sheilan, "Trends in tragedy—An in-depth study of amine system failures," Amine Experts Intl., 2017, online: https://ammoniaknowhow.com/trends-in-tragedy-an-in-depth-study-of-amine-system-failures-2/
2. American Petroleum Institute (API) 14.1, "Collecting and handling of natural gas samples for custody transfer," 8th Ed., 2022.
3. Nesler, T., "Gas measurement has key role in Sarbanes-Oxley Law compliance," *Pipeline & Gas Journal*, September 2005.
4. Fleming, M., Neale Consulting Engineers, *Hydrocarbon release – Dry gas seal integrity survey report (Offshore Technology Report)*, Health & Safety Executive (UK), November 2000.
5. Brown, A., *et al.*, "Comparison of methods for the measurement of hydrocarbon dew point of natural gas," National Physical Laboratory (NPL) Report AS 3, May 2007, online: https://eprintspublications.npl.co.uk/3874/1/AS3.pdf

With a long history of dewpoint measurement systems, **PAUL STOCKWELL** created International Moisture Analysers (IMA) in 1991. From the outset, the company intended to have the ability to look at multi-species analysis, and Stockwell served on working parties for the National Physical Laboratory in the UK for the improvement of moisture measurement, providing dewpoint measurement training for a variety of techniques for metering engineers. With 35 yr of experience in oil and gas systems, he was instrumental in the introduction of laser absorption spectroscopy using tunable diode lasers for natural gas measurements. He also assisted in the development of the first TDL system for natural gas that has now become an industry-standard method for moisture measurement in natural gas. As Managing Director for 20 yr, Stockwell has gained insight into the safety and cost impacts of processes and their problem areas.

In 2017, he led the de-merger of IMA to form Process Vision. Stockwell is named inventor on 16 granted patents, with 22 pending patents, and firmly believes that a thorough understanding gained through imaging can make a significant difference to the oil and gas industry. The author can be reached at paul.stockwell@processvision.com.

Scroll down to read