LIQUID CARRYOVER DETECTION
TO IMPROVE FOAM MANAGEMENT

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Introduction

Before natural gas can be transported, acid gases must be removed, together with any liquids that could condense in the pipeline. Operators must also meet water and hydrocarbon dew point specifications before the gas is suitable for entry into a national gas transmission system as sales gas.

The Natural Gas Journey

From the gas well, through gas treatment, transmission and use, there many points where liquids are injected and then removed in order to avoid corrosion, remove hydrogen sulfide (H_2S) and carbon dioxide (CO_2). The critical points are shown in Figure 1 where all liquids should be separated prior to moving the gas forward in the system. If liquids are not effectively removed, safety and process efficiency are compromised.

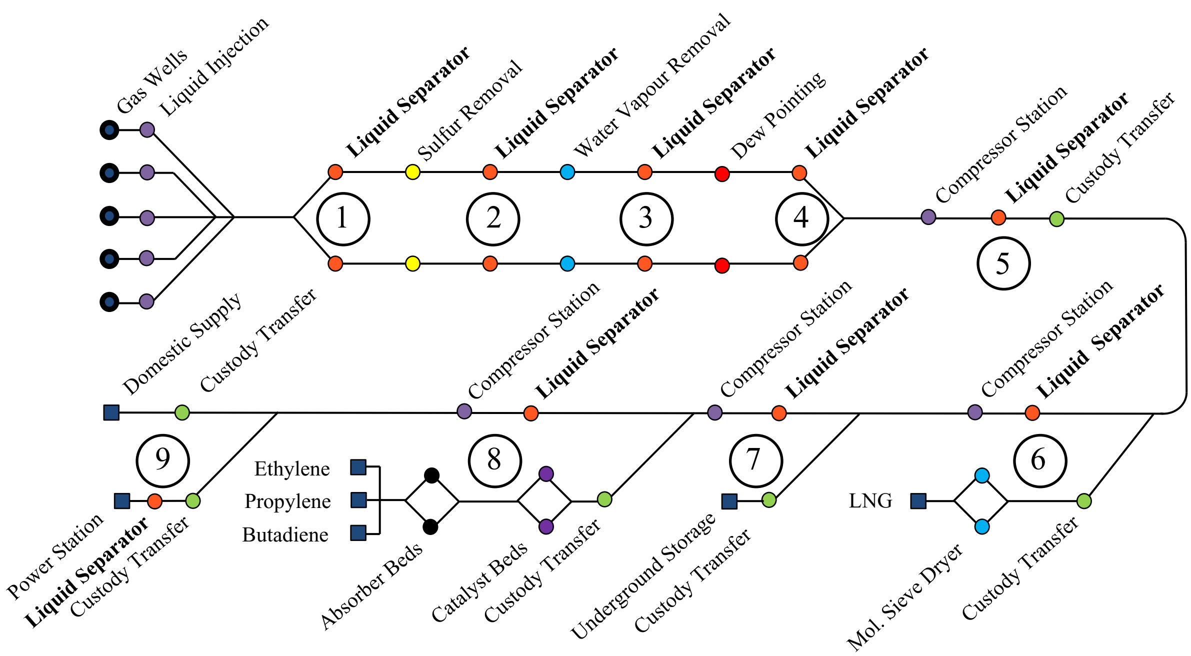

Figure 1 - Natural Gas Journey

Gas/liquid separators are not 100% efficient, 100% of the time; in fact, their performance is one of the most common causes of problems and capacity constraints.

Foaming, flow surges, start-up, shutdown, and flow ramping are all common causes of liquid carry-over. Referring to Figure 1:

1. At the entry to gas treatment process, all condensate, corrosion inhibitor and anti-hydrate liquids present in the gas stream should be removed. When gas/liquid separation is not 100% efficient, foaming occurs during gas treatment that can severely limit production, in some cases by as much as 20%[1].

2. When the de-mister pad or other filtration systems fail to be 100% efficient, loss of amine due to carry-over into the dehydration system can be costly and cause further process problems in the dehydration unit.

3. Liquid carry-over from the dehydrator can cause serious damage to mercury removal or other absorber type beds. In addition, dew pointing reduces the temperature of the gas to remove as much condensate as possible. Figure 2 illustrates the freezing point of an aqueous triethylene glycol solution[2]. As glycol enters this system, it freezes at a temperature dependent upon its water content, and causes blockages and temperature control problems.

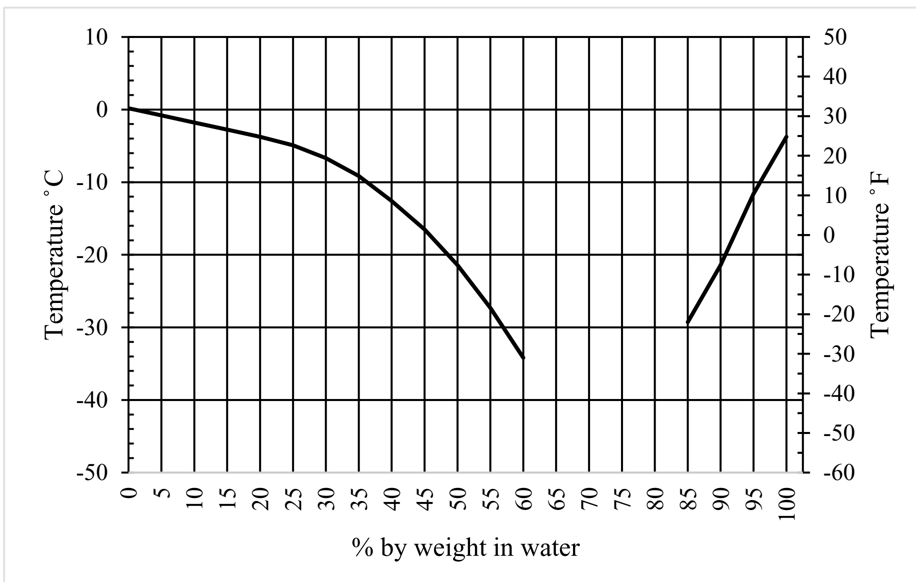

Figure 2 - Freezing point of TEG[2]

4. Effective removal of condensate ensures that maximum value is extracted from the gas. If any liquids are present in the sales gas at the custody transfer point, the supplier is accountable for breaking the tariff agreement and can be fined or the gas network can slam the export valve until the problem is rectified. The supplier can also be held responsible for the clean-up costs and rectification of the network. In addition to contamination of the gas network, if the gas is unexpectedly wet, both ultrasonic and orifice flow meters, calibrated for dry gas, will over-read and increase uncertainty from 0.5% to 5% or more[3&4], causing fiscal measurement errors. The Sarbanes Oxley bill[5] requires due diligence for fiscal measurements, and the effect of wet gas in a dry gas flow meter is an issue that needs attention by flow assurance engineers.

5. In gas networks, there have been instances where liquids have caused corrosion to the point of pipeline rupture[6]. Also, liquids build up at the low point in a gas network until enough liquid is present to move forward as a large "slug". Separators should be monitored and maintained to ensure optimum performance in order to prevent liquids from entering compressor stations. Compressors themselves can be the source of contaminating gas supplies, allowing around 5 gallons (20 litres) of lubrication oil into the system when seals fail.

6. Molecular sieve dryer used to achieve low levels of humidity prior to liquefaction in Liquid Natural Gas (LNG) production are damaged when liquids are entrained in the incoming gas. More importantly their life is insidiously reduced by small, constant, undetected liquid carry-over.

7. Gas stored in underground caverns needs to be dried prior to re-entry to the transmission system. Glycol carry-over can cause the gas to be outside of specification, and cause damage to plant and equipment.

8. Fuel gas, and other gases present in refineries and petro-chemical plants are often required to be free of liquids. This is because catalysts, distillation towers and absorption beds can be damaged or written-off if liquids are present. It is important that gas going to the flare stack does not contain liquids: if it does, flaming liquid showers anything below the flare stack.

9. Liquids in the fuel gas entering gas turbine power stations and Combined Heat and Power units (CHP) cause significant damage by corrosion, pitting or melting the turbine blades. An imbalance in the rotors then occurs leading to complete failure.

Gas pipeline contracts stipulate the gas quality. Instrumentation is installed at the custody transfer point to ensure that gas quality is maintained in terms of BTU, CO_2, H_2S and H_2O content. The contracts also state the following regarding liquids and other objectionable materials:

Typical Interstate Pipeline Contract

> "The gas shall be commercially free from objectionable odors, bacteria, solid matter, dust, gums and gum-forming constituents, free liquids, crude oil, and any other substance that might interfere with the merchantability of the gas, or cause injury to or interference with proper operation of the lines, meters, regulators, compressors, processing plants, or appliances through which it flows."

FERC - Cimarron River Pipeline, LLC

Typical Intrastate Contract

> "The gas shall be commercially free from particulates or other solid or liquid matter which might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters and other equipment of Transporter."

FERC - Central Kentucky Transportation Company

Despite these contracts, there is no check for *liquid carryover* at custody transfer points, the industry has spent considerable effort developing coping mechanisms and practices to deal with the contamination that should not occur. Liquids continue to find their way into gas networks around the world, as suppliers, as well as gas networks, are largely unaware of the levels of liquid contamination in terms of glycol and amine carryover.

Some networks are having to pig 4 times a year, others have added extra knock-out drums and separation devices. Pigging alone creates high costs for both the pipeline operator and suppliers. When pigging takes place the gas velocity has to be slowed to the optimum speed for a pig of 11 mph. The suppliers cannot ship as much gas as normal when the line is being pigged and the loss of income is shown on Table 1. For illustration, normal operating conditions are calculated at:

Pipeline pressure: 1015 psi (70 Bar)
Gas density: 58.14 Kg/m^3
Normal velocity: 25 mph (37 ft/sec, 11 m/sec)
Gas price: Average Henry Hub October 2019

Table 1 - Loss of Production Costs per Day Due to Pigging

Pipe Diameter (inches)	Normal Capacity (MMscf/Day)	Capacity when Pigging (11mph)	Difference	Cost of Pigging per Day
12	1,333	587	747	$1,804,956
24	2,666	1,173	1,493	$3,609,911
30	3,333	1,467	1,867	$4,512,389
36	4,000	1,760	2,240	$5,414,867
40	4,444	1,955	2,489	$6,016,519
48	5,333	2,346	2,986	$7,219,823

Processing liquids (amine and glycol) used in desulphurisation and de-humidification are the most common liquids found in transmission networks. These are designed to have an extremely low vapour pressure, and therefore are difficult to detect with conventional gas analysis systems. Indeed, gas analyser systems are intentionally designed to avoid and remove liquids that may be entrained in the gas stream. In the case of water vapour and hydrocarbons, analysers can report that the gas is saturated, but not the amount of liquid in the gas stream.

Lack of suitable monitoring and alarm systems are the reason liquids are known as “the silent killer”, often discovered to be the cause of serious incidents.

Many designs of separators exist. Figure 3 and Figure 4 illustrate examples of a separator and a filtration system.

Many filter systems have been designed prior real-world liquid loading being known and gas flow rates can be different from the design criteria provided to the separator or filter vendor. This can result in under-sized systems or, with cyclonic separators, cause an under-performance when gas flows are low.

On some sites space restrictions, or other considerations, mean that a straight run of pipe to the gas inlet is not possible. A 90° bend close to the inlet to the separator causes entry gas to swirl and causes a preferential flow within the separator. This means that the gas velocity is higher than designed and therefore causes a higher liquid loading on the demister.

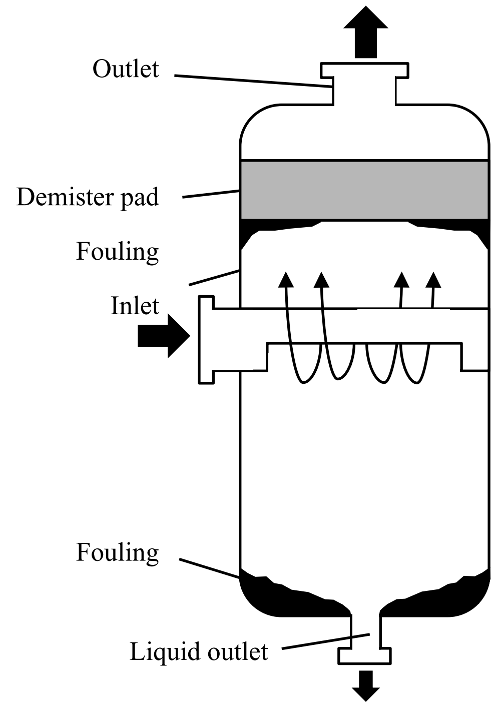

Figure 3 - Vertical Separator

Assuming the filtration system is well designed and fit for purpose, and site design is good, other problems, including operator errors, reported include:

Separators (Figure 3):

- Fouling of the demister causing high velocities through the unfouled portion.
- Fouling at the liquid outlet causes the liquid level to rise and allows re-entrainment of liquid to take place.

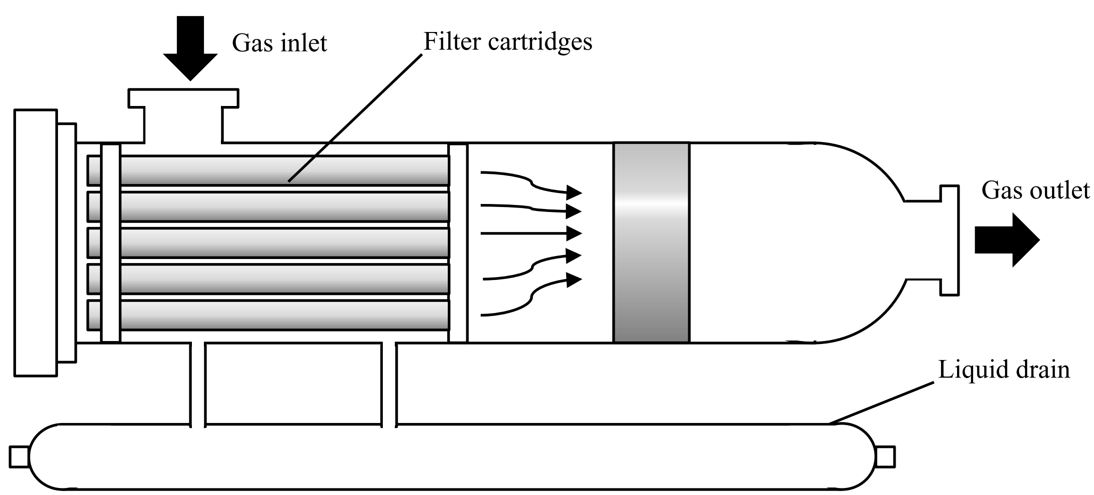

Figure 4 - Horizontal Coalescing Separator

Coalescing filters (Figure 4) can achieve higher rates of liquid removal, but design and operational issues can cause performance problems:

- Filter cartridges not seated properly allowing a gas path to bypass the filter.
- No differential pressure across the filter not recognised as a problem.
- Pressure washing disposable filters and re-using them despite visible holes in the filter.
- Cutting filter cartridges to fit the filter body.
- Wrong filter cartridges or no filter cartridge fitted.

Existing Instrumentation at Custody Transfer Points

Gas chromatographs, water dew point and hydrocarbon dew point meters are present at many custody transfer points. As gas analysers, it is important that liquid contamination does not enter the sample system and affect results. In order to avoid contamination on the pipe walls, GPA guidelines[7] recommended sampling using a stabbing probe to sample within the middle third of the pipeline diameter (Figure 5). Recent work undertaken by the Southwest Research Institute[8] indicates that a sample taken above the middle third of the pipeline diameter is preferable, and lowers the risk of probe breakage due to flow induced vibration, while retaining the ability to reject liquids at the sample probe. Normally, membrane filters and coalescing filters are installed prior to the analyser to remove any liquid present in the sample stream. Failures in analyser filtration systems often lead to an analyser filling with liquid, despite the specification for sales gas requiring that there should be no liquid.

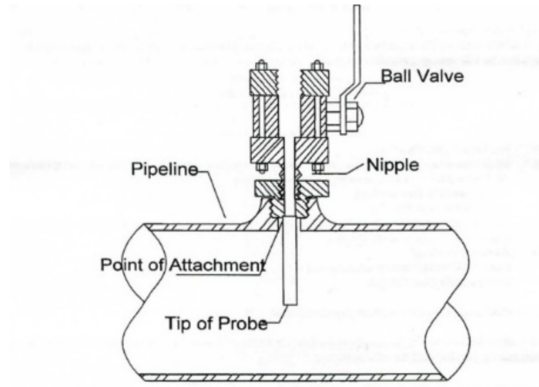

Figure 5 - GPA Guidelines for Sample Take-off

Current Technology to Determine Separator Performance

Current techniques to determine separator performance require significant man-power performing a one-off survey using a slip stream method to take a sample off the main gas flow and run it through a high efficiency coalescing filter, weigh the resulting liquid gathered over a known time, measure the flow in both the main line and the side stream, then extrapolate the weight of the liquid gathered to represent the liquid flow in the mainline. These surveys are often undertaken over a short time period of up to 24 hours, and usually produce a result that exceeds the specification for the separator. A survey undertaken by Nexo Solutions[9] determined that the liquid flow downstream of a separator was significantly higher than normal separator specifications (Table 2).

Table 2 - Separator Specifications Applied to Site Survey Conditions

	Separator Specification	Equivalent US Gallons/day	Equivalent Litres/day
Survey Result		981	3,714
US gal/MMscf	0.1	58.8	223
PPMw	1	10.2	38.6
US gal/MMscf	0.01	5.88	22.3
PPMw	0.01	0.10	0.39
PPMw	0.002	0.02	0.08

The result of 981 US Gal/day de-rates the performance of a standard separator (58.8 Gal/day) by over 16 times (981/58.8 = 16.6).

Detection of Liquids in Pipelines

When liquid is co-mingled in a gas flow, a number of flow regimes exist for low level liquids in gas flow:

- Distributed Flow: where an increasing number of droplets land on the pipe wall but there is no stream.
- Stratified Flow: A film of liquid forms on the pipe wall and slowly moves to the bottom of the pipe to form a stream.
- Wavy Stratified Flow: As stratified flow but there is sufficient energy in the gas to disturb the surface of the liquid to form waves.
- Partial annular flow: Sufficient energy is contained in the gas phase to cause the liquid to hold up on pipe walls.
- Full annular flow: Sufficient energy exists in the gas flow to support a moving film of liquid around the whole inner wall of the pipe.
- Beaded Flow: The stratified flow has decreased and begins to break up into a discontinuous flow of liquid beads that move slowly along the pipe floor.
- Mist Flow: Sufficient energy (a combination of pressure and velocity) exists together with sufficient liquid to form an aerosol.

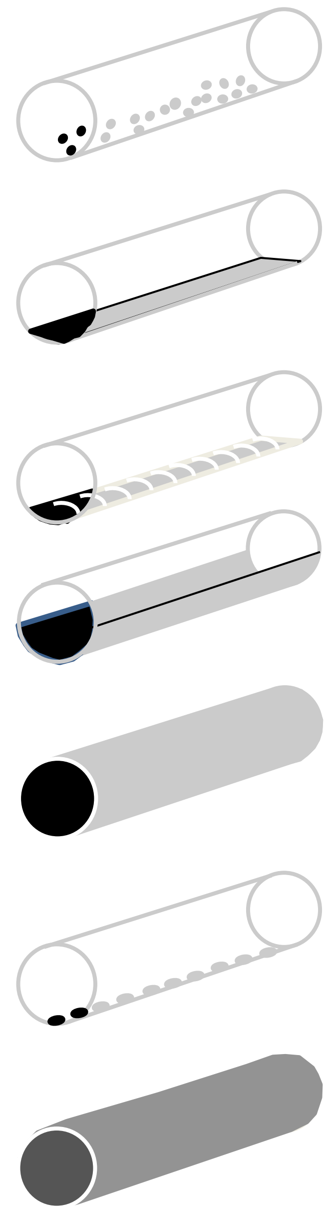

Figure 6 - Different Flow Regimes

Prior to the development of a liquid detection system, the way low levels of liquid flow in a gas pipeline needs to be understood.

As stated earlier, the work that Nexo Solutions performed established that a separator system was passing over 16 times the amount of liquid compared its specification. Table 3 models liquid glycol carryover flowing in sales gas from a gas processing plant and illustrates the liquid flow expected at a variety of gas flow rates between 250 MMscf and 1000 MMscf. The glycol flow is calculated from a separator with a 0.1 US Gal/MMscf specification, and then de-rates its performance by 5, 10 and 20 times to investigate the liquid flow rates presented under these fault conditions.

The results are then plotted on flow regime map in Figure 7 where it can be seen that a combination of stratified wavy flow turning to a mist flow at higher gas and liquid flows might be expected.

Table 3 - Applying De-rated Separator Performance to Gas Flows in a 36" Pipe

Pipeline Diameter:	**36”**		
Pressure:	**1000 psi (69 Bar)**		
Separator Specification:	**0.1 US Gal/MMscf**		
Gas Flow: MMscf/day (Mm^3/day)	**Gas Velocity: ft/sec (m/sec)**	**De-rated Factor**	**Liquid Flow: Gal/day (m3/day)**
✚ 250 (7.0)	11.2 (3.4)	1	25 (0.096)
		5	125 (0.47)
		10	250 (0.95)
		20	500 (1.9)
◆ 500 (14.6)	22.4 (6.8)	1	50 (0.19)
		5	250 (0.95)
		10	500 (1.9)
		20	1000 (3.8)
● 750 (21.2)	33.5 (10.2)	1	75 (0.28)
		5	375 (1.4)
		10	750 (2.8)
		20	1500 (5.7)
■ 1000 (28.3)	44.7 (13.6)	1	100 (0.38)
		5	500 (1.9)
		10	1000 (3.8)
		20	2000 (7.6)

Test-loop work has been performed by many parties and can produce flow regime maps such as the flow map below (Figure 7) digitized from Shell DEP[10].

Figure 7 illustrates a flow regime in relation to the Froude number. This is defined as the ratio of the flow inertia to gravity and may be calculated as:

Gas Froude number: $FrG = vG\sqrt{\rho G}/\{(\rho L - \rho G)gD\}$

Liquid Froude number: FrL= $vL\sqrt{\rho L}/\{(\rho L - \rho G)gD\}$

Where:

vG	= velocity of gas	vL	= velocity of liquid
ρG	= density of gas	ρL	= density of liquid
g	= acceleration due to gravity	D	= internal diameter of pipe

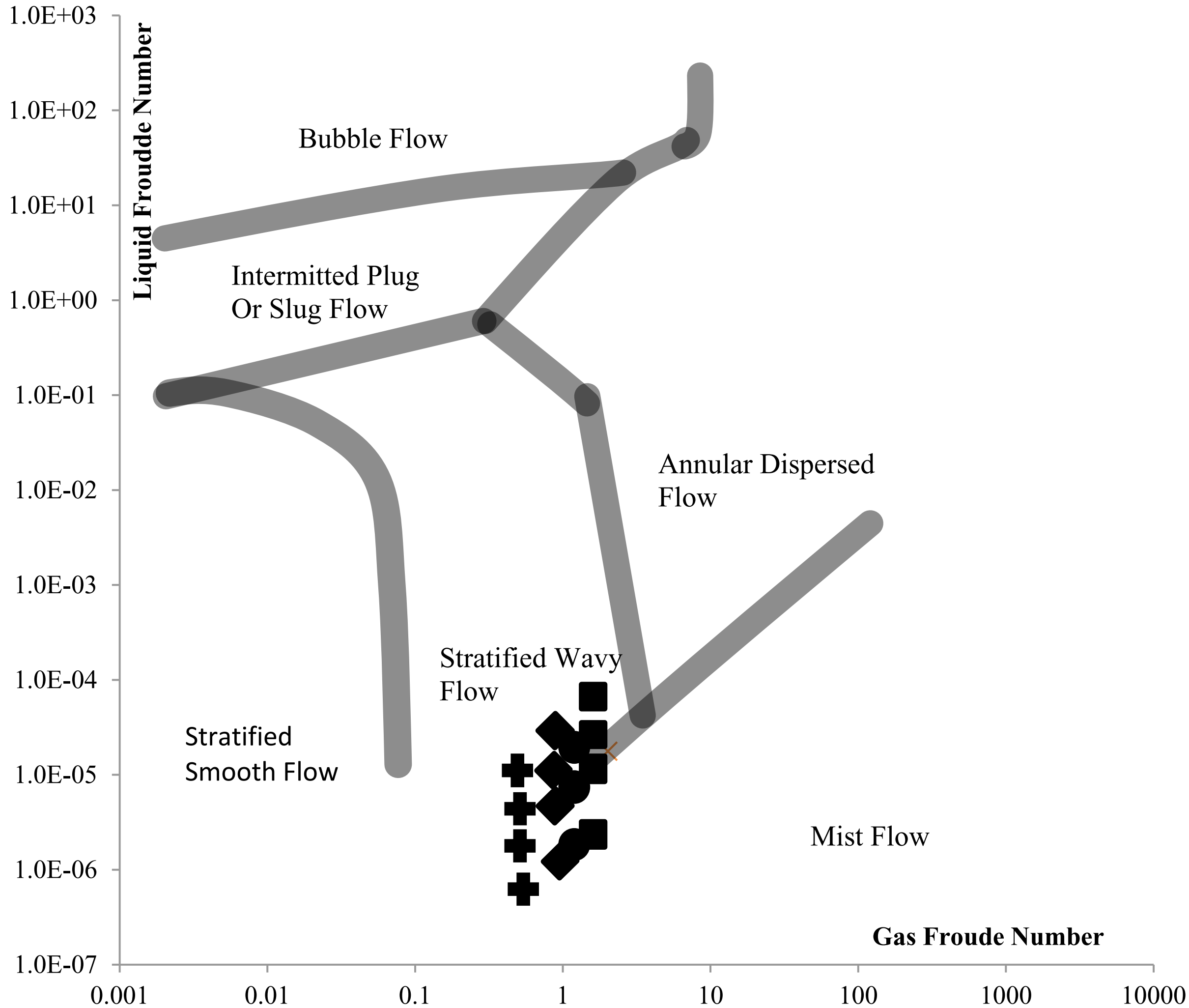

Figure 7 - Two-Phase Flow Regime Map for Horizontal Pipes[10]

Many parameters affect which of these flow regimes will prevail;

- gas velocity
- liquid flow
- pressure
- pipeline diameter
- miscibility of liquids
- angle of pipe
- gas density
- liquid density
- viscosity
- surface tension
- pipeline wall surface quality
- upstream pipe geometry

One of the parameters that dominates the flow regime is pipe diameter, and mixed phase flow test-loops with a diameter of greater than 8" simply do not exist. Most of the tests performed in mixed phase flow loops do not consider the low level of liquids seen when dry gas flows are contaminated with liquid, and so the resolution and accuracy cannot be relied upon. Further work is required to confirm the regime maps for large diameter pipes and low liquid flows. The new instrumentation discussed in this paper will help in this work, and will relate real world data to improve computational fluid dynamics (CFD) models.

A New System to Detect Liquid Carryover

The development of a new system (LineVu) has taken nine years to navigate through safety and certification issues. After some initial research into the problem, it was found that a permanent monitoring system to detect low levels of contamination in gas flows did not exist, so techniques such as ultrasound were tested on a flow-loop but were found not to have sufficient sensitivity to detect low levels of liquids and aerosols traveling in a high speed gas flow. Work moved on to a laser triangulation technique that could determine the depth of a liquid in the pipe.
While proving very stable and linear at atmospheric pressure, testing at 1000 psi (69 Bar) revealed an interesting phenomenon.

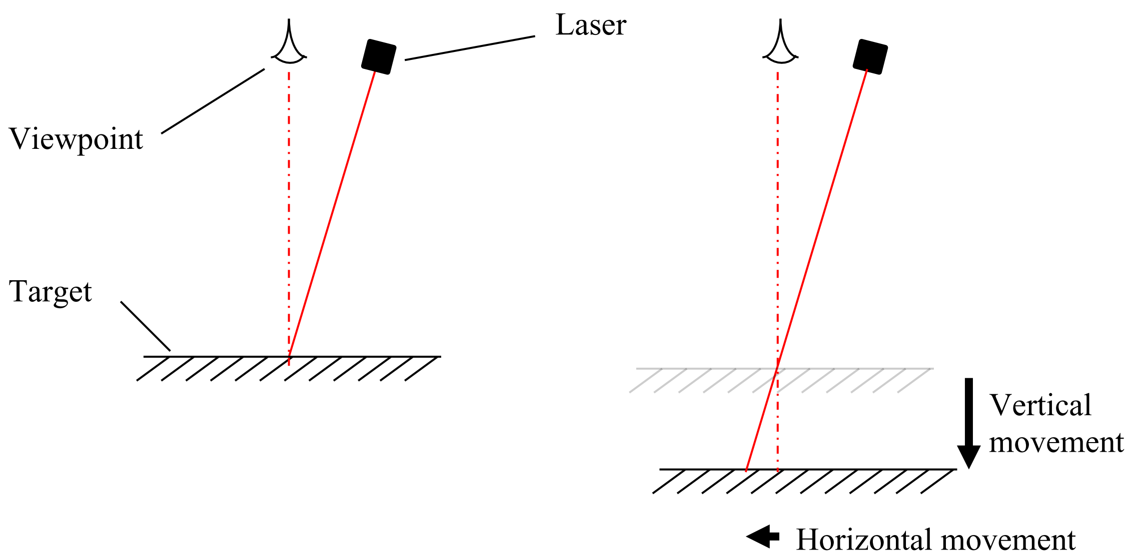

Figure 8 - Laser Triangulation System

With a triangulation system (Figure 8) a laser light source illuminates a target at a slight angle. A laser spot can be observed where the laser hits the target. If the target moves towards or away from the light source, the position at which the laser hits the target moves left or right in proportion to the vertical movement of the target. This is a well-known and stable form of distance measurement and produced good linear and repeatable responses. However, when testing at high pressure in a test rig exposed to weather differences, random movements in the target position were observed that increased when the sun came out. Testing revealed that the amount of movement seen related to the rate of temperature change. The reason for this is that refractive index is directly related to density. While at atmospheric pressure the density changes for a 5°C shift is minimal (Table 4), but at high pressure, the density changes due to temperature are more significant:

Table 4 - Natural Gas Density Changes Due to Temperature and Pressure[11]

	Low Pressure		**High Pressure**	
Temperature (°C)	21	26	21	26
Pressure psi (Bar)	14.7 (1)		1000 (69)	
Density (Kg/M^3)	0.698	0.686	54.349	52.918
Density Difference	**0.01 Kg/m^3**		**1.43 Kg/m^3**	

As these position changes of the laser spot are random, they can be averaged given sufficient data points, and when testing with real liquid flows the signal difference between no liquid and a small amount of liquid was extreme. While satisfying the requirement to detect liquids, the signal variations were so extreme that determining the depth of liquid was not possible. During testing cameras were arranged to both zoom into and determine the small movements in the laser spot and show the full field of view. It became apparent that image processing on the full field of view would provide a better determination of the severity of the liquid contamination and its characteristics than the laser system.

Another benefit of moving to image processing is that the system could also show hydrates, foam, grease and other solid contamination.

Process Vision has developed a camera and illumination system, using image processing to trigger an alarm if contamination is seen. It has been designed with a secondary containment system enabling the camera housing (Camera Can) to be safely installed and operated on high-pressure

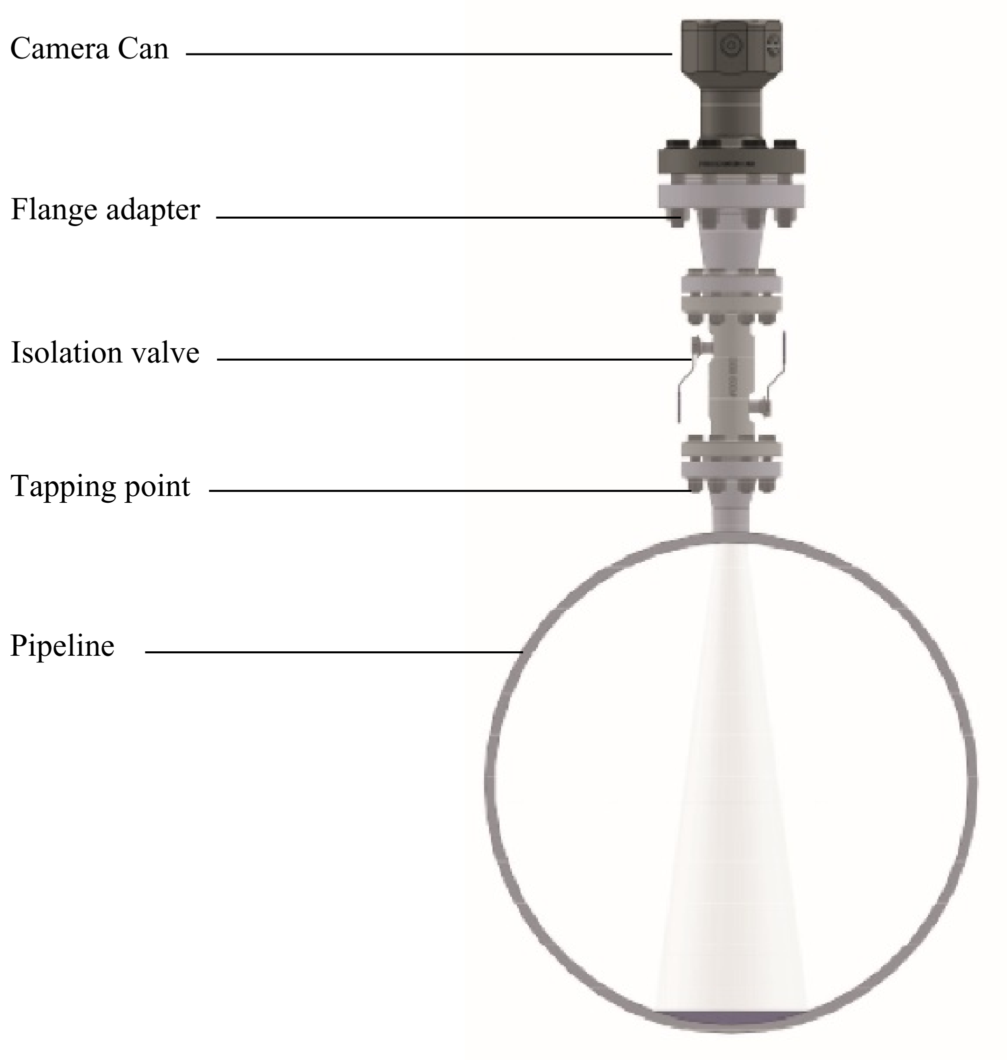

Figure 9 - Camera Can Mounted on a 24" Pipeline

gas networks and processes. A live video stream is available to operators to allow improved process decisions to be made, and to review process incidents. Upon activation of the alarm, LineVu automatically starts to record the event.

The on-pipe system (Camera Can) is mounted above the pipeline (Figure 9) and behind an isolation valve, allowing lines to be pigged, and creating enough stand-off above the gas stream to prevent contamination of the optics when liquids are present. Also, the heat produced from the illumination system is managed so that the windows remain a few degrees higher than ambient and therefore condensation on the windows is prevented when monitoring pipeline gas that is saturated.
The standard camera can has a 3” class 600 RTJ flange; if the site valve flange is different, a flange adapter can be fitted. As the flange adapter can be fitted with a small bleed port and valve, it gives the ability to provide a feed to a pressure sensor and allow the tapping point to be used for both contamination and pressure monitoring.

Figure 10 – LineVu Camera Can with Secondary Containment System and Window Puck Assembly

The camera and illumination assembly are mounted on the Window Puck (Figure 10). The Window Puck houses illumination and camera ports. All ports house a pressure retaining sapphire window. Pressure testing from a systematic viewpoint has been performed at over 700 Bar G (10,152 psi) without damage. The Window Puck assembly is inserted into a secondary containment chamber in the Camera Can body, ensuring that, in the unlikely event of a window or seal failure, there is no loss of containment. Electrical connections exit the secondary containment chamber via a pressure rated feedthrough to the upper chamber. The Camera Can bodies go through four pressure tests: one for the upper chamber to comply with certification; one test for the Window Puck; one on the lower chamber; and once assembled, a final pressure test on the complete Camera Can.
Figure 10 illustrates a window puck suitable for a 2” or larger tapping point. Other pucks are available that allow installation down to a 1” tapping point.
Image processing is performed in a local interface unit up to 100 yards from the Camera Can (Figure 11). In the interface unit, time, date and location are burnt onto the video together with “housekeeping” data and, if required any process data that may be obtained from the site SCADA or DCS system. On playback of an incident, all relevant process data is on screen in real time.

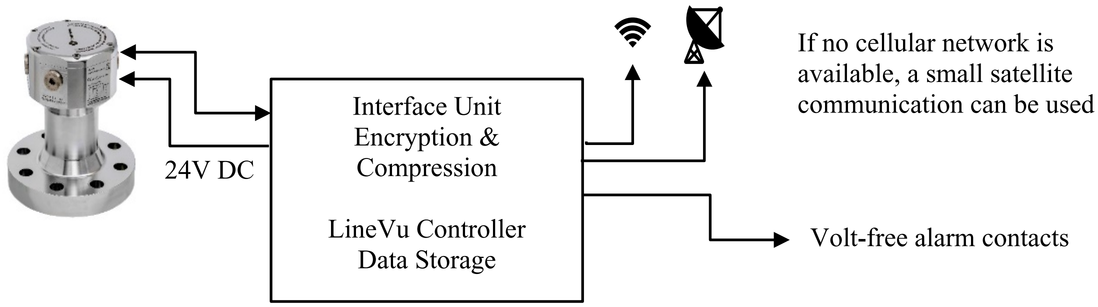

Figure 11 - LineVu With Connection to the Interface Unit and Controller

The user interface is web compliant allowing integration into existing SCADA and DCS systems. When contamination is detected via image processing, an email, SMS text or push notification is sent to authorized users who can login to see a live video stream from mobile phones, laptops, or PCs. Sections of video or still shots can be exported to send to third parties, or to be included in reports. When installed at a custody transfer point, the data can be made available remotely to ensure improved accountability. When multiple suppliers are connected to a network or tie-back, video with date, time and location can be sent to the supplier as evidence of the contamination event, which could initiate a similar rectification or shut-in process to that for other incursions of the gas quality, such as H_2S or water vapor level above agreed limits.

Figure 12 - Camera Can Mounted on a Gas Entry Point to the UK National Transmission System

A system installed at a gas entry point to the UK national transmission system (Figure 12) is providing data relating to the contamination levels of the incoming gas[12]. On the user interface (Figure 13), gas flow is always shown as flowing from left to right. The image shows debris on the pipe floor which is relatively stable and believed to be grease used to lubricate valves. Metadata associated with the image is burned onto the video and is available on playback of an incident.

Figure 13 User Interface

Improved Foam Management

In gas processing systems, process engineers have the unenviable task of making critical process decisions based on an educated guess of what may be happening. For example, an increase in differential pressure across a glycol contactor may indicate foaming or an increase in fouling. The normal response is to add de-foaming agent but, adding too much causes foaming to increase and it can then overflow past the liquid separator at the exit of the process.

In de-sulfurization, amine-based liquids remove acid gases. In dehydration units, glycol-based liquids (MEG or TEG) are used to remove water vapor. The liquid enters the gas contactor at the top and exits at the bottom and is then pumped to the re-boiler to go through a heat cycle to regenerate prior to returning to the top of the contactor. Any entrained liquids in the gas entering the contactor, therefore build up in the amine or glycol liquid and cause increasing problems (Figure 14):

- short-term: with many of the liquids added at the wellhead being surfactants, foaming is a common problem in the industry. It significantly reduces production.
- long term: hydrocarbon liquids leave carbon deposits that can build up inside the contactor and reduce its efficiency.

Figure 14 - Carbon Deposit Build up in a Gas Contactor[13]

In a survey undertaken by Sulphur Experts[14] of 148 production failures in natural gas amine plants, it is clear that foaming caused by liquid carryover is a large problem. In fact, 92% of plant failures in gas treatment plants are due to liquid carry-over with 31% of failures due to foaming.

Normal practice at a foaming event is to reduce the production flow rate to 40% to 50% of the normal flow until de-foamer can be added and recovery is achieved. The relative frequency of foaming incidents is shown in Figure 15.

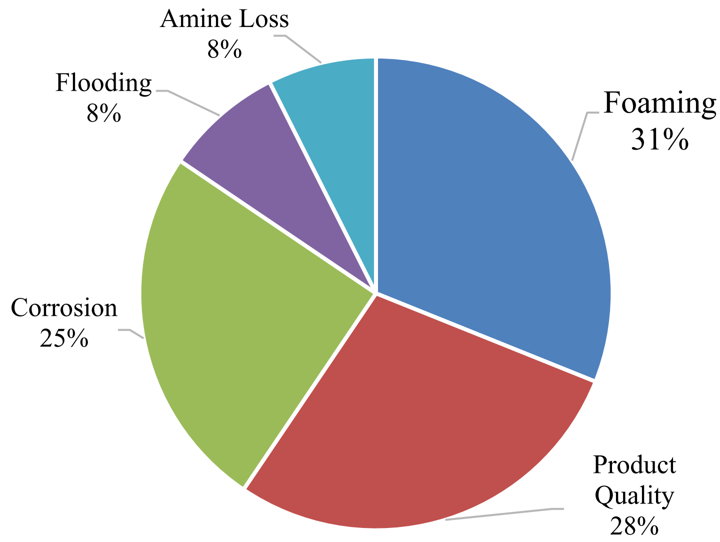

Figure 15 - Causes of Process Failures[14]

For many gas treatment plants, production is being limited by the risk of foaming. Using the liquid detection alarm of a LineVu system as an early warning to alert operators of a potential foaming event enables operators to add de-foaming or anti-foam agent earlier than they can with current methods. The causes of liquid carryover can be divided into two categories: operational that may be occasional or temporary in nature; design problems where liquid carryover is a constant or frequent problem.

- Operational
    - Coalescing filter cartridge failure: fouling/flooding
    - Coalescing filter cartridge failure: mechanical damage
    - Coalescing filter cartridge failure: incorrect seating or sealing of filter cartridges
    - Flow ramping: start-up and shutdown
- Design
    - Gas flows higher than design capacity
    - Liquid loading higher than design capacity
    - Incorrect design: sizing, type, insufficient straight run prior to separator
    - Gas flow lower than design specification. (cyclone filters)

By installing a LineVu system before the gas treatment plant, operators will be provided with an alarm and a live video stream of separator performance. With this additional information, de-foamer can be added as soon as a liquid event is detected, improving on current practices of responding to a foam build up by monitoring differential pressure or liquid levels in downstream vessels.

Further, by installing a LineVu system in either the flash drum or at a point half way up the gas contactor, the build-up of foam can be observed and provide a more sensitive and unquestionable reason for adding de-foamer, and therefore can find the optimum flow rate versus de-foamer ratio for maximum production and efficiency.

Conclusion

With better information available to process engineers, it is expected that LineVu will increase up-time, improve process safety, lower maintenance costs and extend asset life. It is expected that better knowledge of liquid carryover will enable engineers to improve the performance of separators in the field to provide better process control and accountability.

This new technology literally opens a window into high-pressure processes and allows users to view the product that is being bought and sold. With better knowledge of contamination levels and performance of gas separators, engineers can make significant improvement to process efficiency by determining the optimum flow rate for a separator, or use the information to diagnose filtration faults to increase throughput at gas processing plants.

Without this key information that allows operators to stop pipeline contamination, many coping mechanisms and practices have to be employed in the gas industry today. Armed with better information, processes can become more efficient and pipeline operators will be able to reduce the number of times they pig the line, and increase production by $Millions each year for both suppliers and pipeline operators.

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