# ERRORS IN HYDROCARBON DEWPOINT CAN LEAD TO LARGE LOSSES FOR GAS PROCESSING PLANTS

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## ABSTRACT

New technology is enabling a live stream video feed from inside the gas pipeline to be available in the control room, and it is revealing that, in some cases, mixed-phase flow is present while the hydrocarbon and water dewpoint systems still report that the gas is dry. With the ability to look directly into high-pressure gas pipelines, this paper provides evidence of how this new technology is discovering that phase separation and NGL recovery systems are not necessarily performing to specification.

For gas analysis systems to provide long-term reliable service, it is important that they are presented with a representative *gas* sample from gas pipelines. This paper shares data from videos of real-world installations and, with the knowledge gained, explores aspects of API 14.1 that provide a circular argument and allow liquids to pass into gas transmission networks that lead to millions of dollars of lost revenues for the gas processor, increased operational costs on the transmission system operator, and pose serious safety threats. Calculations of errors caused by wet gas in the two fiscal measurements of flow and calorific value will also be presented.

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.

Two-phase flow in sales quality gas is considered a fault condition but ensuring that liquids are avoided or filtered in analyzer sample systems to protect gas analyzers can lead process engineers to be unaware when these liquids are present, allowing liquids to pass through custody transfer points without tripping alarms and contaminating gas transmission systems.

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## Introduction

All dry gas flows have the potential to become wet gas flows, and accidental liquids in gas transmission networks create hidden financial costs and pose serious safety risks. Good phase separation at both the front and back end (NGL recovery) of gas processing is vitally important to ensure an efficient process and, in some cases, can provide an easy win to boost production, reduce maintenance, and improve safety.

Liquid carryover is the number one 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 have shown that, unless phase separation is performed to a high level at low temperature, it is common for sales quality gas to be transported as a wet gas, despite water and hydrocarbon dewpoint systems indicating that a dry gas is present. The carryover of glycol from dehydration systems is common, yet it is currently not a parameter that is monitored at the custody transfer point.

The impact of liquid carryover in gas processing and gas transportation touches many different disciplines within the industry: asset integrity and reliability managers, process control managers, flow assurance managers, and lost and unaccounted-for flow engineers. This paper aims to pull together the different disciplines that need to understand what is going on in the process or pipeline to better manage the performance of gas systems and reduce the frequency of liquid carryover events.

There is currently no permanent monitoring system for phase separation and filtration systems. These systems protect vital assets and processes, and their performance should be judged on the contamination allowed through rather than the contamination that is stopped.

For the first time, engineers are able to view inside a live pipeline and reveal that when these "dry gas" systems are monitored, often mist or stratified flows are present. With this monitoring in place, the performance of different gas processing trains on a gas treatment plant can be balanced to minimize carryover and the differences investigated. Action can be taken to improve phase separation to reduce the threat of foaming, comply with tariffs and reduce the cost of operations for Transmission System Operators (TSOs).

With gas sampling systems that comply with 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. The impact is that crucial measurements such as flow, and calorific value are compromised, resulting in losses of billions of dollars annually for the industry. Captured using innovative process camera systems, videos demonstrate how unseen liquids can slip past gas analysis systems undetected and leave operators unaware of problems until it is too late. This paper shows that validation of flow monitoring and calorific value measurements can be improved by monitoring with a process camera system.

## Process Cameras

With commercial contracts and legal requirements that gas is shipped, bought, and sold on a dry gas basis, using process cameras capable of imaging high-pressure gas pipelines and systems has, for the first time, allowed operators to see what is really happening in the pipeline. This has revealed that liquids are more prevalent than one might expect. The impact of liquids on dry gas flow measurement and gas analysis is enormous, and this new metric can be used to better understand and improve the performance of gas processing, gas transportation and the uncertainty budget for fiscal measurements.

Providing experienced process engineers with live-streaming video gives real-time feedback to operators and often produces data that questions the status quo.

*A Camera on the Pipeline*

The process camera is normally mounted vertically on a pipeline and provides views of the pipeline floor by illuminating and imaging through an isolation valve (Figure 1.). This setup is for ease of 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, or very close to, the gas velocity, while stratified flows have lost most of the kinetic energy and, in large diameter pipelines, travel at the bottom of the pipe. There are many factors that determine the velocity that stratified flows travel; density, viscosity, gas flow rate, pressure and surface roughness are some of the factors. When live streamed to the control room, there are often reports of liquid streams being present while no other alarms have been activated. The metadata of the image, for instance, 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.

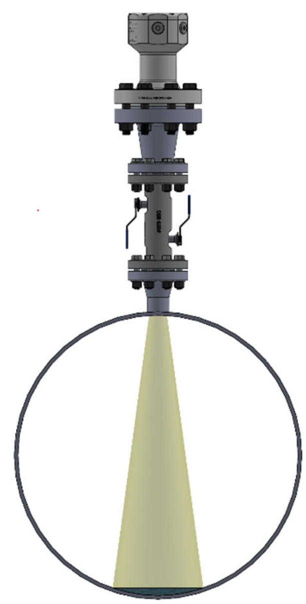

**Figure 1**- Showing how LineVu is mounted on a gas pipeline.

The live streamed video and the associated data are proving to be a useful new metric for control of 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. TSOs are using the data as an additional quality check on gas entering the gas network.

## The Gas Journey

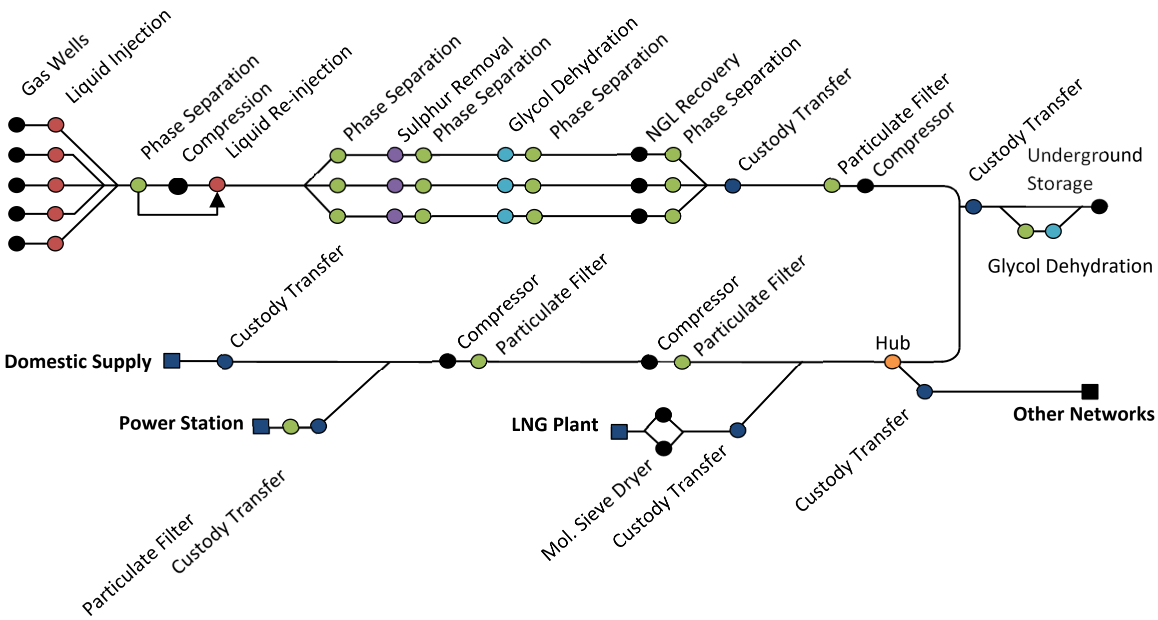


**Figure 2** - The Gas Journey

Figure 2 is a simplified diagram of the journey the gas takes from the gas well to the points of use. At the gas wells, crude oil, condensate, water, and sand are usually present. In addition, further liquids are added: hydrate mitigation, corrosion inhibitors, and bactericides are common. At this stage, it is an intentionally mixed phase flow, but all add to the liquid loading of the gas entering the front-end phase separation at the gas treatment plant. There may be compression between the gas wells and gas processing plant where liquids are removed and, if local disposal is not economical, re-injected. So, compressor oil can be added to the possible contaminants of the gas as it enters the gas processing plant.

## Liquid Carryover in Gas Processing

Ideally, only gas enters gas processing as, in a detailed survey by Amine Experts [1] indicates, the efficiency of the front-end phase separation is vital. 400 amine plant failure cases were included in the survey finding three main causes shown in Figure 3. Each of the 400 cases had a cost to the operators of between $250k to $250m.

The survey concludes that the main causes of:

- Corrosion is poor circulating amine quality or insufficient regeneration of the amine.
- Foaming is contaminated gas at the inlet.
- Product quality is insufficient heat.

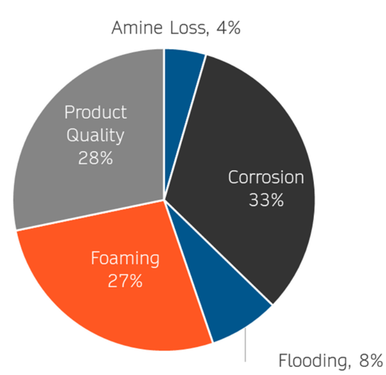


**Figure 3** - The three main causes of amine plant failure [1]

Two out of the three causes of plant failure (poor amine quality and 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 (Figure 4) show the causes of foaming.

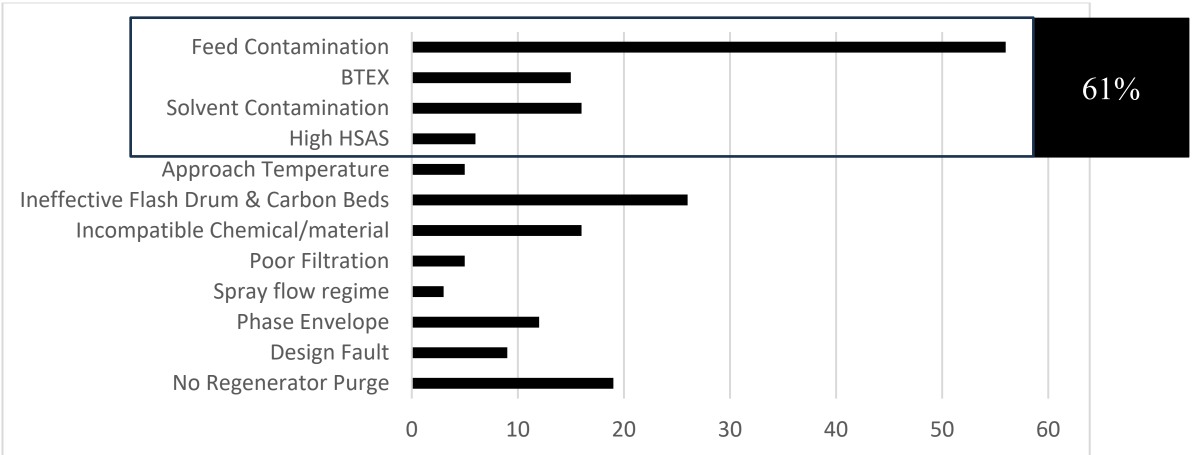


**Figure 4 -** Main causes of foaming [1]

Four causes are due to contamination of the inlet gas, indicating that incorrect phase separation is the number one cause (61%) of foaming events. With better 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 foaming event, rather than cut the gas flow to get foaming under control. De-bottlenecking studies can be taken to understand when and how breakthrough occurs, implement better maintenance practices on demister pads, justify the cost of improving the phase separation if required and prove that the solution worked.

As foaming is a major risk, many gas plants limit the gas flow and are running under the optimum flow rate to give a "margin" in the case of foaming. The greater confidence that a process camera brings allows operators to run a little closer to the optimum in the knowledge that they can react quickly if a liquid event occurs.

As the gas moves through de-sulfurization and de-humidification, large quantities of liquid come into intimate contact with the gas. If not separated, liquid carryover will contaminate the next stage of the process, NGL removal. Once the gas is sweet and dry, the usual method of extracting as much NGLs as possible is to reduce the temperature of the gas, force the gas below its hydrocarbon (HC) dewpoint and separate the liquids.

When temperature reduction is achieved totally or partially by pressure reduction, it creates the right environment on a flowing gas to produce a sub-micron mist flow, the most difficult type of liquid to filter out. In many cases, the temperature is achieved, but while good technology is available to separate mist flows, it is not commonly implemented. As the gas warms back up, the liquids vaporize, making the vapor phase saturated with respect to hydrocarbons, and the HC dewpoint and process temperature are the same. The situation is exacerbated as sample systems intentionally separate anything that has already changed phase.

When pipelines are pigged, one of the frequent components removed is glycol. Like compressor oil, it is not a liquid that is vaporized easily, and gas analyzers cannot monitor glycol carryover as the vapor pressure is so low. For glycol to be present in gas pipelines, it must pass through two-phase separators, and it is unlikely that glycol would pass through the phase separator at NGL recovery without allowing NGLs to also pass through. In these cases, operators do not gain the full financial benefit of NGL recovery but still have the expense of reducing the temperature of large volumes of gas.

*How Much is Too Much?*

When observing contaminated gas flows, the question is, how much is too much? The usual term of reference for sales gas is the tariff between the gas processor and the TSO. The wording of a typical interstate pipeline contract is shown below:

> "The gas shall be commercially **free from** objectionable odor, 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*

While there are no numbers quoted in the same way as moisture and hydrogen sulphide limits, the wording gives the TSO the authority not to accept the gas if it is likely that it will damage compressors or other assets downstream. This sets the bar low, as damage to dry gas seals in compressors is caused by contaminated gas.

## Compressor Damage

A survey performed by the Health and Safety Executive in the UK [4] examined 71 compressor failures. Each failure cost \$60k - \$120k plus the loss of production. Both 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 Years
- Survey Results: 1 Year 20 days (average)

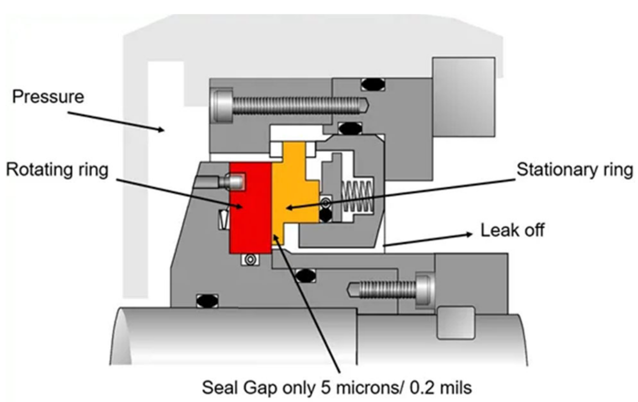


**Figure 5 -** Simplified diagram of a compressor dry gas seal

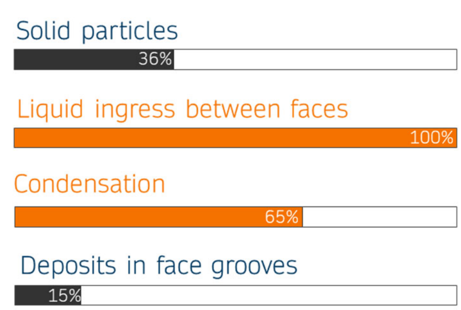


**Figure 6** - Causes of dry gas seal failures

Dry gas seals are usually labyrinth seals where the gap between static and rotating components is around 5 microns, as seen in Figure 5.

The survey found that the main cause of failures was contaminated gas (Figure 6) where 100% of failures showed liquids were found between the faces of the seal. The gap is controlled by gas pressure, and when liquids or solids are present, they bridge the gap allowing a greater temperature to be conducted which compromises the gap. When the two parts touch, excessive wear takes place, shortening the life of the seal significantly and, in some cases, causing a loss of containment.

## Examples of Contaminated Gas Flows

The four images below (Figure 7) show clean gas, stratified flow, and mist flow. Features on the pipe floor can provide points of reference. It should be noted that the still shots below do not convey as much information as the videos from which they are taken.

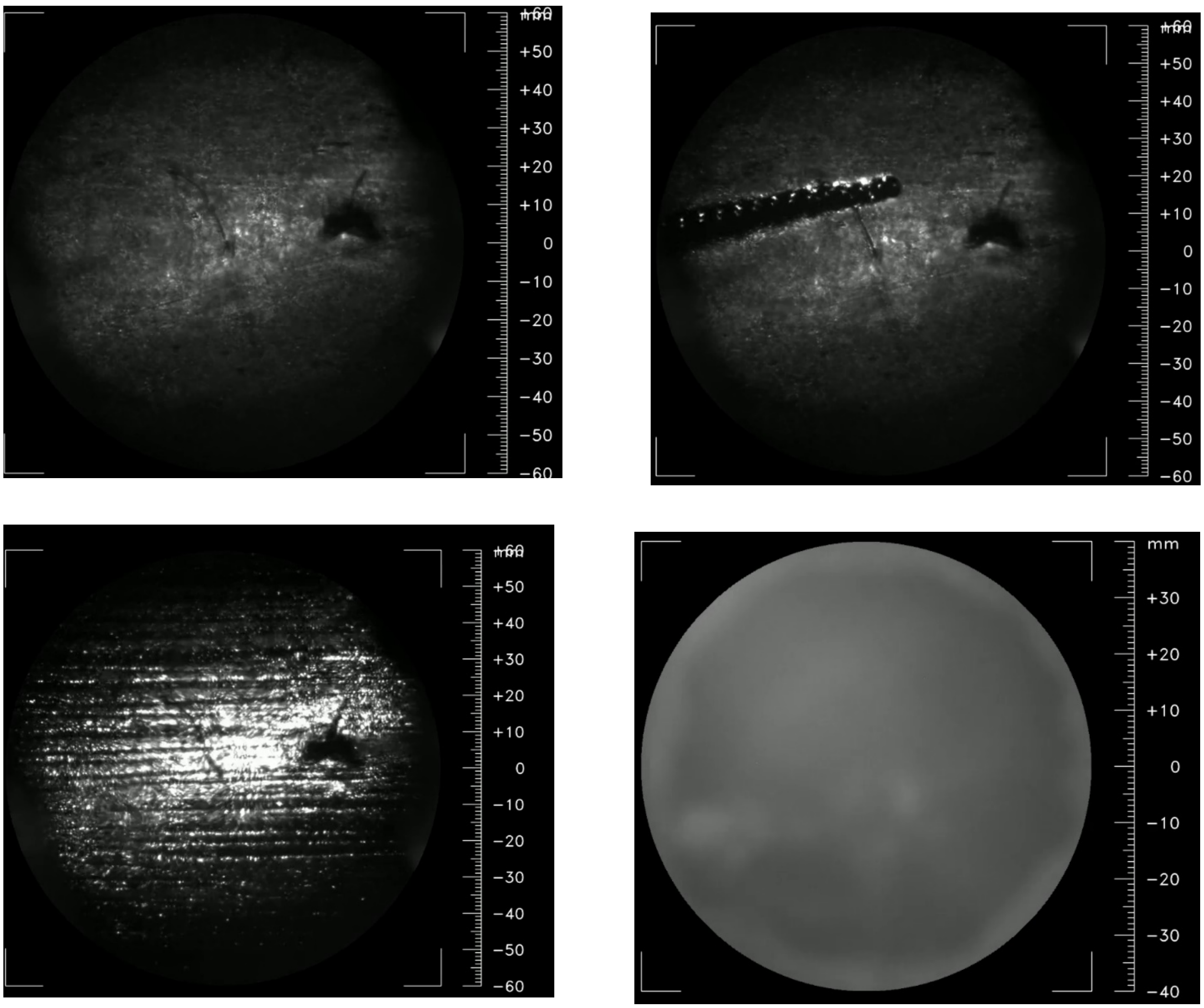


**Figure 7** - Top left - dry gas. Top right - stratified flow of compressor oil.
Bottom left – stratified flow of condensate. Bottom right - mist flow

The photos above 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 around 15 ft/sec (4.6 m/sec). The top left is dry gas flow, and the top right is a stratified flow of compressor oil with a surprising worm-like shape. Bottom left is a stratified flow of condensate in many small streams, and bottom right, 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 relatively low gas velocities and mist flows occur at relatively high velocities. However, observations of stratified flows have occurred at both low and high velocities, and mist flow observations at both high and very low and even stationery gas flows. Many parameters affect the way contamination moves in a mixed-phase flow in large-diameter pipelines, e.g., a mist flow in a 100-mile (161-km) pipeline can turn into a stratified flow if there is a momentary drop in gas flow rate. Temperature, liquid density, liquid viscosity, pipe surface roughness, bends, and flange joints all have a part to play. It is common to see mist and stratified flows at the same location on different occasions and occasionally at the same time.

## Diurnal Changes

When mist flow is present, it is common to observe diurnal (time of day) changes. The level of mist flow increases during the day and decreases at night. It is very repeatable, and in some cases, the pipe floor is completely obscured at the maximum point of mist flow. This phenomenon is like diurnal variations in water dewpoint on overground pipelines. While the dewpoint may be -40°F (-40°C) with a 5 - 10 °F (3 - 6°C) variation, it is explained by the pipeline being heated by the sun during the day and any water vapor in the pipe wall (and the material on the pipe wall) out gasses into the gas flow and "wets" the gas as shown by a small increase in the dewpoint. At night the reverse happens, and water vapor achieves equilibrium with the pipe wall (and the material on it) in the reverse direction, and the dewpoint decreases again.

It is, therefore, believed that the presence of repeatable diurnal changes indicates that volatile gas components, most likely NGLs, are present.

## Dry Material Conveyed in a Pipeline

Figure 8 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 move down the pipe because of 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.

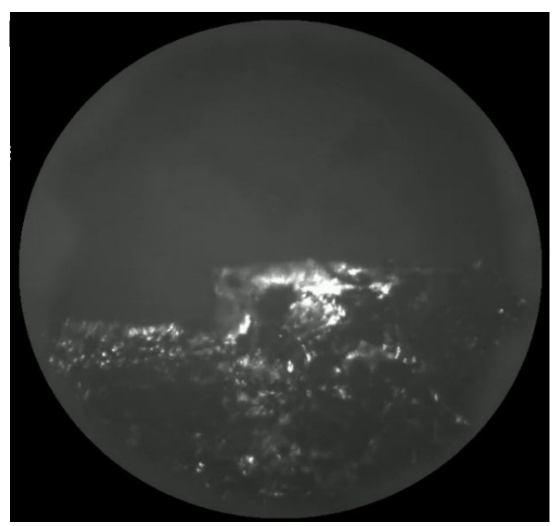

**Figure 8** – Grease like contamination

# Liquid Separation Within the Pipeline

Figure 9 indicates a phenomenon observed in a 36 in. (0.91 m) diameter pipeline. It shows two stratified flows: compressor oil, the worm-like flow at the top and bottom of the field of view, and a stream of liquid in the center. It appears these two different-density liquids have separated in the pipeline. It is hoped that this data can be fed back to improve CFD models.

Gas flow is from left to right, and the liquid flow is at an angle to the "apparent" gas flow. As the installation was 10 ft (3 m) from the second of two 90° bends, it is likely that the gas flow is twisting and, as liquid flow is derived from friction with the gas flow, the gas is pulling the liquid flows up the side of the pipeline. Full annular flow in large-diameter pipelines has not been observed to date.

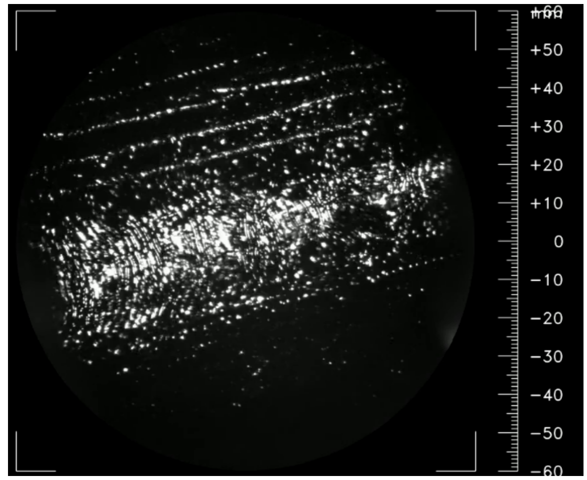


**Figure 9** - Dual liquid flow

# Errors in Fiscal Measurements - Calorific Value

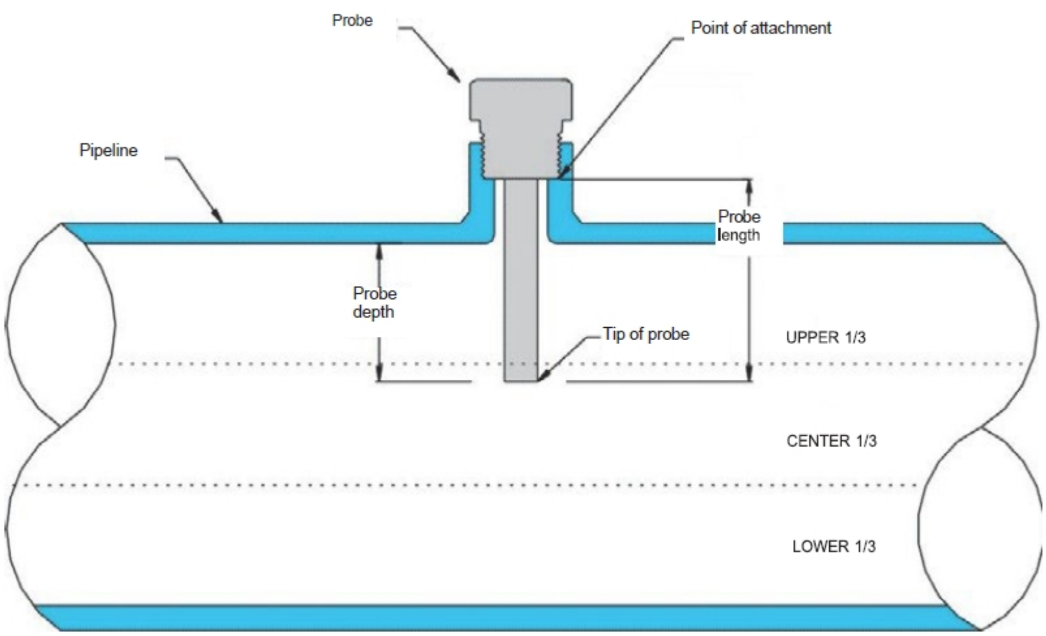


**Figure 10** - Stabbing probe for gas analysis[6]

It is important that gas chromatographs (GCs) and other gas analyzers are protected from liquids. API and GPA standards require that stabbing probes or quills are used to remove the gas samples from the middle of the pipeline (Figure 10) to avoid any contamination on the pipe wall. Additional membrane or coalescing filters are used between the tapping point and the gas analyzer to ensure long-term, uninterrupted service. The sample system is, therefore, providing a representative *gas* sample to the analyzer where any liquids present in the pipeline (glycol, amine, and NGLs) are not included in the sample to the GC and other gas analyzers.

When liquid onset starts, as seen in Figure 11 below, 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. 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, and the liquid evaporated over 24 hours. As the liquid was volatile, it ruled out glycol (MEG and TEG) and compressor oil, leaving only NGLs as possible suspects. 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 as, in many cases, measured HC dewpoint is much wetter than calculated HC dewpoint.

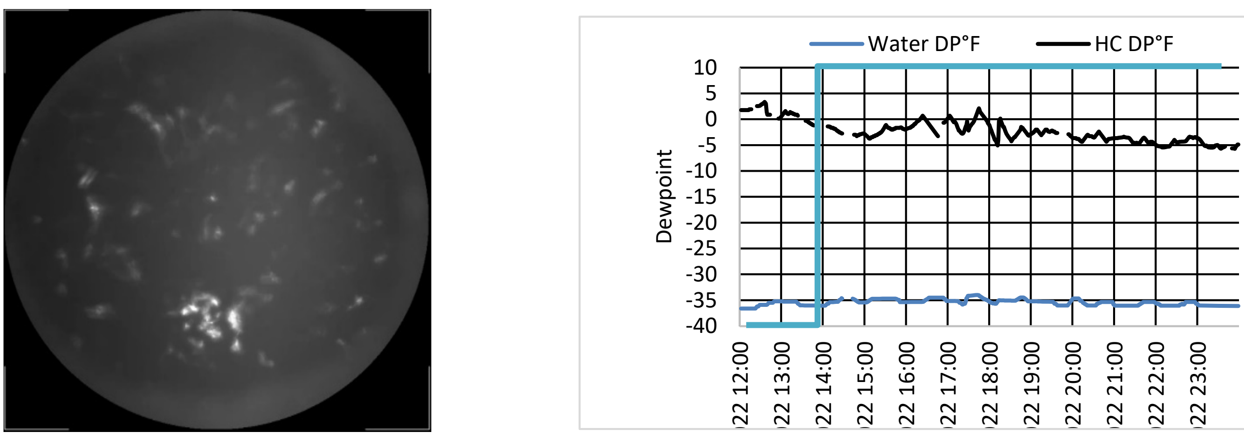


**Figure 11** - Stratified flow of NGLs on the floor of a pipeline and dewpoint trace indicating no change at the onset of the contamination event.

It is important to note that during periods of mixed-phase flow, there will be large errors in calorific value. Getting a true picture of the calorific value of the fluid stream in mixed-phase flows is complex. Despite wet gas being common in gas transmission lines it is outside the scope of API 14.1 used in the design of gas sampling systems:

Even with iso kinetic sampling operating at high temperatures and a GC that can process both gas and liquids, 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, and at present, this means that:

- Measurements made at custody transfer points are in significant error when a two-phase flow is present, and
- Operators are unaware when mixed-phase flow is present.

Installation of a process camera validates gas analyzer measurements when there is single-phase flow and alerts operators when a mixed-phase flow is present.

# The Role of API 14.1 and ISO 10715

The use of process cameras has revealed that there is usually a large difference between the HC dewpoint reported on the SCADA (Supervisory Control and Data Acquisition) system that indicates the gas is dry, and what is observed to be present in the pipeline. Initially, these observations drew the conclusion that these liquids observed must be glycol carryover as this liquid is not a measured parameter in custody transfer systems. However, as can be seen above, HC liquids can be present in the pipeline without reporting a high HC dewpoint. API 14.1, and ISO 10715 are the international standards used for designing and operating gas quality measurement systems. The standards are intended for custody transfer measurement systems conducting fiscal measurements. They are useful for ensuring that natural gas samples are representative and reliable for analysis by gas chromatography (GC) and other methods. The standards ensure that gas analyzers operate reliably and do not suffer from liquid contamination problems that are caused by liquids dropping out in the sample system, causing errors, and increasing the uncertainty of measurement. Both standards clearly state that a representative gas phase sample should be presented or delivered to the analyzer and that the standard(s) do not cover two-phase flow.

API 14.1 additionally states:

> ***B.3 Multiphase Flow***
>
> *Sampling of multiphase flow is outside the scope of this standard.*
>
> *Sampling of multiphase (gas and liquid) mixtures is not recommended and should be avoided if at all possible.*
>
> *Current technology of natural gas sampling is not sufficiently advanced to accomplish this with reasonable accuracy.*
>
> *When sampling a multiphase liquid-gas flow, the recommended procedure is to eliminate the liquid from the sample.*
>
> *The liquid fraction of the multiphase flow may contain water and hydrocarbons.* ***The hydrocarbons can contribute significantly to the energy content (measured in British thermal units [Btu]) of the gas, and their presence in the gas line should not be overlooked."***

ISO 10715:2022 states:

> "*On occasion, a natural gas flow can have entrained liquid hydrocarbons. Attempting to sample a wet natural gas flow* ***introduces the possibility of extra unspecified uncertainties in the resulting flow composition analysis****. Sampling a wet gas stream (two or three phases) flow is outside the scope of this document."*

It is clear in the standards that all measurements ignore any liquids that may be in the pipeline, meaning that fiscal measurements of Btu do not take into account the additional energy content of any liquid (mist flow or stratified flow) that has been present in all installations that process cameras has monitored. This may explain why the HC dewpoint does not change when NGLs appear in the gas stream as shown above in Figure 11. It also means that GC data cannot be used to calculate Btu when a mixed phase flow exists in the pipe.

Most custody transfer systems use the GC data to calculate HC dewpoint and calorific value and there have been many incidents where this method has been questioned and shown to be in error[8]. The increased uncertainty caused by the possible presence of liquids should be included in all uncertainty budgets. A process camera system in line with the sampling system and GC will allow for verification that single-phase gas flow is present at the time of measurement and can add further confidence in the measurement values being as accurate as possible. Furthermore, if a camera system inline with the sampling system shows multiphase flow at the time of sampling, the values can be disregarded or isolated so as not to negatively affect performance targets with invalid measurements.

## Estimated Losses Due to NGL "Under the Radar"

The impact of allowing unmetered NGLs entrained in gas supplies into the pipeline can result in millions of dollars of lost revenue for an average size gas processing plant each year. From observations with process cameras, it is common to see mist flows of liquids that could equate to a liquid volume fraction (LVF) of 0.1%. even at this low level, a 100 MMScf/day of gas flow equals 208 Barrels of NGL/day.

Figure 12 shows a graph of lost revenue for various-size plants (at five-year average wholesale pricing), assuming a 0.1% liquid volume fraction is unmetered. This value was chosen as it is commonly used as a reference for "dry gas" in many commercial products and papers. For a 100MMscf/day (2.83 $Mm^3$/day) plant, yearly estimated losses would be at least $2.3 million per year.

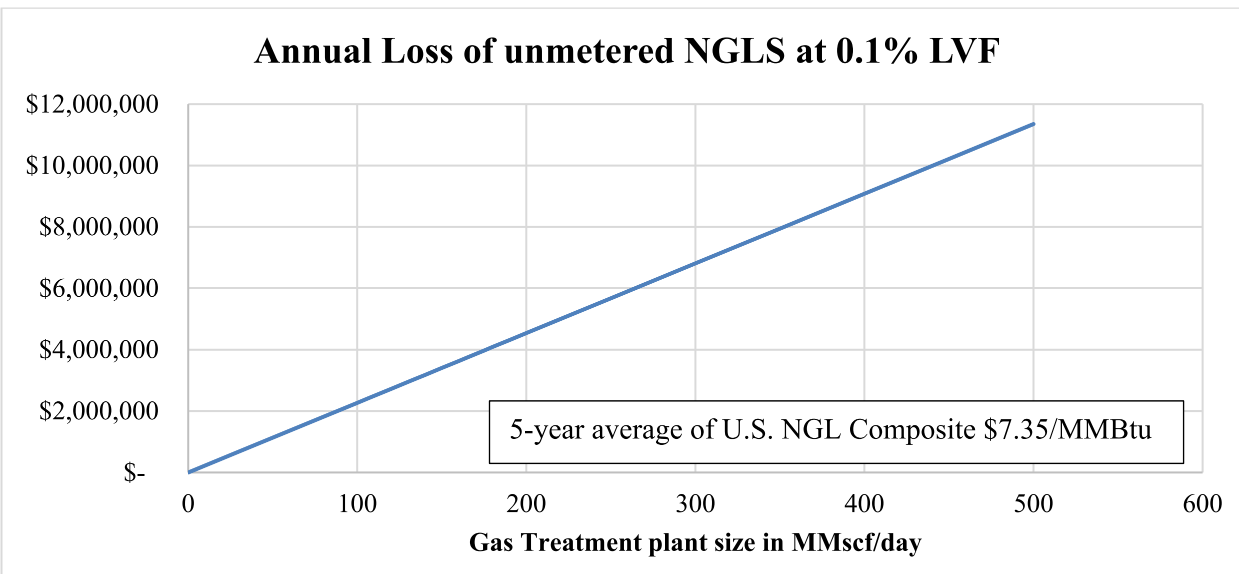


**Figure 12** - Financial Impact of unmetered NGLs into gas flow

## Errors in Fiscal Measurements of Flow

The flow assurance and uncertainty budgets for fiscal flow measurements are required to detail and account for potential errors. Sarbanes-Oxley compliance [3] addresses lost and unaccounted-for (LUAF) flows in natural gas and means that errors should be accounted for. Unexpected liquids in dry gas systems add a substantial amount to the uncertainty budget for flow measurement [2]. It is an important parameter that should be included in all flow uncertainty budgets. Liquid events can interfere with flow measurements in two ways.

Firstly, when liquids are present, dry gas flow meters will read in error [2]. With these errors being up to 2% of reading, one way to reduce the uncertainty is to have an undisputable monitor on the gas flow as an assurance that the gas is a single phase.

Process cameras have observed that when liquid stratified flows occur, they often transport solids that, once the liquid event is over, are dumped on the pipe floor (Figure 13). These solids can be a mixture of iron sulfide, scale and other particles that have either evaded filtration or are a product of reactions with the gas and pipe wall. They are conveyed as a slurry that, with the rapid gas moving above, slowly dries to solid matter and creates a permanent reduction in pipeline diameter. When this happens in flow metering stations, even 0.1 inches of residue (2 or 3 mm) can produce errors of 0.3%. With the overall uncertainty target for fiscal flow measurement being <0.5%, this creates a significant and permanent offset. It should be noted that this error is independent of the flowmeter calibration or type of flow meter used. Flow stations are usually unpiggable and should be inspected and cleaned regularly.

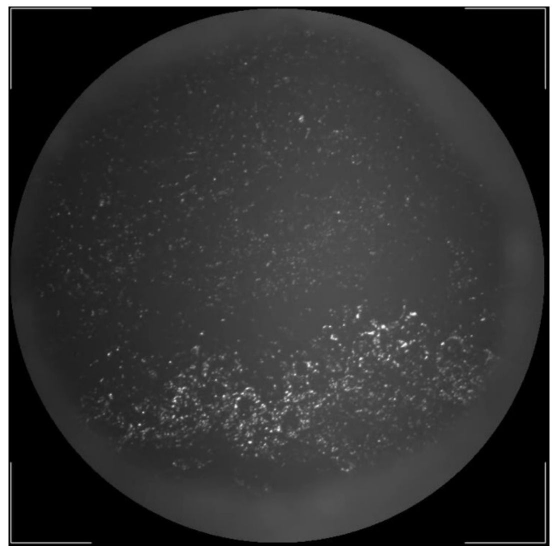

**Figure 13** - Material on the pipe floor after a liquid event

## Pressure Drop Across the Gas Network

As liquid accumulates in the low points of a gas transmission system, it reduces the diameter of the pipeline in that area. Thousands of gallons of liquid hold-up can be present when phase separators are inefficient or fail. The restriction in this area means that there are higher compressor costs to move the gas at the required flow rate.

## Cost of Pigging and Disposal of Contaminants

With traditional pigging costs estimated at between $1.4 million to $3.1 million for a 36-mile (58 km) section [5], pigging is a costly and risky operation. The risk of a stuck pig often means that lines are pigged with progressively more aggressive pigs prior to a smart pig being deployed. If asset integrity managers and pigging crews knew that contamination ingress had been managed and minimized with process cameras noting the contamination events, the risk of pigging operations could be reduced, and the frequency optimized. With less pigging, methane emissions would be reduced from venting or flaring from the pig launcher and receiver. For TSOs with cameras at the inlet custody transfer points, stopping contamination events could substantially reduce pigging requirements and, if contamination has been allowed to enter the gas network, the costs of cleanup (pigging and disposal of the resulting materials) could be allocated to the party that supplied the contaminated gas to the TSO.

## Pipeline Corrosion - Internal

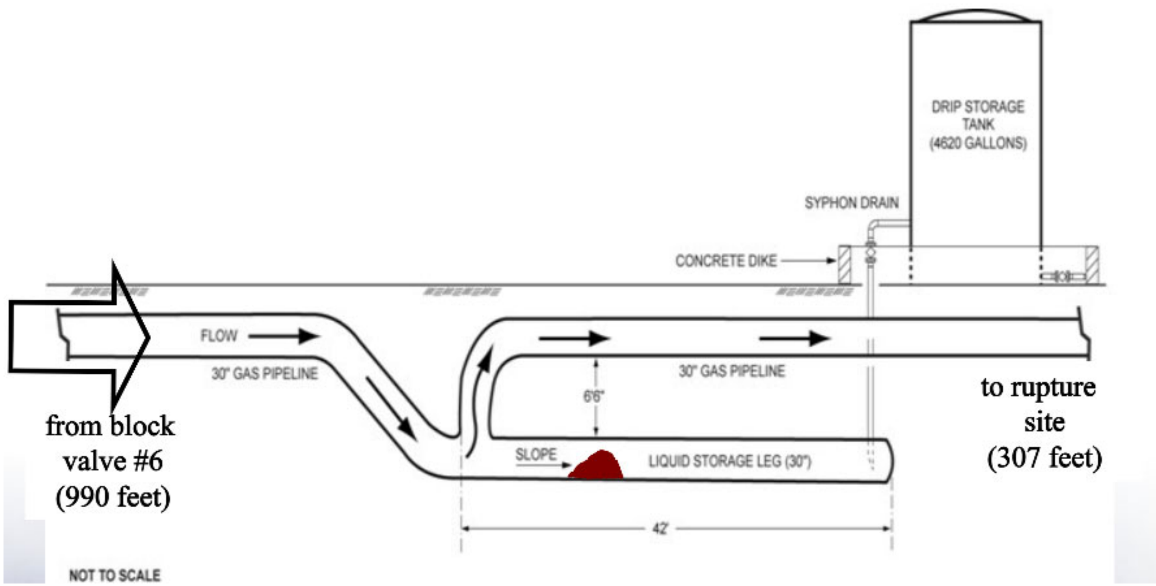


**Figure 14** - Solid Material in the throat of the drip was the cause of the liquid carryover.

Liquid hold-up in pipelines creates an additional risk of corrosion that can lead to pipeline rupture, as happened at the incident at Carlsbad, NM [9]. The cause of the incident was the failure of a “drip” separator (Figure 14). The drip is an underground spur off the main pipeline. The spur is lower than the main line and, therefore, should collect stratified flows of liquid. At Carlsbad, the liquid had also conveyed solid material, which accumulated in the throat of the drip. 80% of the cross-sectional area was blocked by solids. Liquids continued into the pipeline and accumulated in the

**Figure 15a** - The fire after the initial explosion


**Figure 15b** - Rupture site showing crater and bridge supports.

low point section. The investigation found significant internal corrosion had occurred, causing the rupture. Figure 15a & Figure 15b show the ensuing fire and damage caused by the incident that killed twelve people. Monitoring pipelines for liquid carry-over lets operators know if mist or stratified flows are occurring.

## Pipeline Corrosion - External

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 joint is inserted between underground and over-ground sections. However, when solid material is conveyed along the pipeline, it breaches the isolating joint and, being electrically conductive, compromises the CP system.

## Increase Risk to Power Stations

By the time the gas reaches the power station, several factors increase the likelihood of contamination:

- Glycol and NGLs 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.

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

- Stratified flow causes uneven combustion around the turbine, putting high stress on the turbine.
- Blocking of fuel nozzles (Figure 16).
- 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 NGLs if they are present but do not vaporize glycol or compressor oil. It should also be noted that this heat is not available at start-up, and flow starts/flow ramps are where most stratified flows have been observed, leaving power stations vulnerable to liquid events and flow meter errors due to high levels of solid material in the flow meter lines.

**Figure 16** - Fuel nozzle

## The Lifecycle of a Stratified Flow Event

Figure 17, below, shows the total brightness returned to the camera and is one of the parameters that is used as an alarm threshold. This liquid event was caught on two process camera systems on the same pipeline, one on the supply side, the other with the TSO around 985 ft (300 m) downstream of the first camera. When the gas is dry and stable, the difference between the maximum (light) and minimum (dark) values is small. The liquid event was a stratified flow of liquids which started around 8:30 pm on the supply side when the difference between the maximum and minimum values rapidly increased but did not reach the TSO side until around 1:00 am the next morning. On the supply side, the event was completed and returned to dry gas but was extended by the time the liquids got to the TSO side. As the camera systems were able to demonstrate that the event had finished on the supply side, even though the TSO was still seeing liquids, it was decided, on that occasion, to allow the gas to continue to flow in the expectation that the liquid flow would decrease and stop within the following few hours.

**Figure 17** - The lifecycle of a liquid event

## Summary

Process cameras can be used to great effect as a cost-effective method to increase production in gas plants and help further increase revenue by helping to improve and monitor NGL recovery. Transmission system operators can now include liquid carryover in gas quality measurements, to reduce uncertainty of calorific value and flow measurements at custody transfer points.

Liquid carryover has, up till now, been a problem that engineers are normally not aware of until it is too late. This new technology is now allowing gas processing and pipeline engineers to highlight where carryover is occurring, prove under what process conditions carryover happens and ensure any mitigation measures are effective and remain effective over time.

By reducing the amount of liquids entering transmission systems, risks of corrosion and loss of containment particularly at compressor stations are reduced. Maintenance and operational costs will also be reduced with lower levels of liquid carryover in gas systems.

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