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LIQUID, HYDRATES AND FOAM DETECTION IMPROVES OPERATIONAL EXCELLENCE IN GAS TREATMENT

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1. ABSTRACT

Before natural gas can be transported, acid gases (CO_2 and H_2S) have to be removed, as well as any liquids that could condense in the pipeline. Gas/liquid separation is required both upstream and downstream of gas treatment plants. The separator 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 and foam carry-over. Liquids in a gas network collect at low points where they cause corrosion or are swept out as a slug of liquid that can damage sensitive equipment downstream. Undetected liquids cost the industry $millions every year in damage, lost revenue and labor costs. This paper describes the 9-year development of a new permanently installed camera-based monitoring system, operating at high-pressure, that can improve operational excellence by providing a continuous live video stream of pipeline activity. Using image processing, an alarm can be activated if liquids, hydrates or foam are detected at very low levels. This improves operational decisions that lead to lower downtime, higher process safety and increased production. By installing the system at custody transfer points, accountability can also be improved. Gas analysis systems, normally installed at custody transfer, are designed to avoid and remove liquids, allowing liquid contaminants to pass without triggering an alarm. There have been many instances of contamination events causing significant damage to compressors, gas turbines or even pipeline ruptures. Now, separator and knock-out pots can be monitored leading to significantly lower levels of liquid contamination in tie-backs and gas networks leading to optimization of costly pigging or reverse flow cleaning processes.

Keywords: Image processing, Pipeline monitoring, Operational excellence, Optimization

2. BACKGROUND

In many ways, natural gas could be considered as perishable goods. If a supplier has a problem that requires lowering or stopping production, the loss of revenue cannot be made up tomorrow. When plant upsets occur the costs to operators are high; not only is there extra labor, consumables and replacement parts, the loss of revenue can often run into $millions. One of the major causes of disruption across the upstream, midstream and downstream sectors is liquid carry-over. The industry has not been able to determine liquid carry-over events for a number of reasons discussed in the paper, often making the cause of plant upsets something of a mystery until it is too late and urgent reactive action needs to be taken. Liquid carry-over is a common problem in the industry, and one that, up to now, has been largely overlooked. However, since the downturn in the industry there is a new drive to improve operational excellence. New technology, digitization and the internet of things can all play an important role in giving operators better information on which to base their decisions to:

- improve process safety
- increase productivity
- decrease maintenance costs

This paper aims to illustrate the cost of contamination across the supply chain and some of the tools needed to improve operational performance in the gas supply and distribution industry.

There have been many years of experience in monitoring gas systems and gas pipelines. Gas analyzers are common at both processing plants and custody transfer points. Over the years improvements in dew point meters (water) and hydrocarbon dew point monitoring have provided valuable information on gas quality. However, there are shortcomings in the suite of analyses commonly found at these points. Processing liquids like amine or glycol are specifically designed to have very low vapor pressures, so looking for their presence in the gas phase does not help determine if they are present in liquid phase.

Water and hydrocarbon dew point meters report the temperature at which condensation will start in the gas flow that is monitored. While these analyses will alarm if the gas analyzed is outside a given specification, they are used to report an unsaturated gas or impending doom as it approaches its dew point, once the gas is saturated the dew point and the gas temperature are the same. They are unable to report how much liquid is in the pipeline. It is like measuring the level of coffee in a cup by monitoring the humidity above it.

It is the liquids used in gas processing (amine & glycol) that are most commonly found in an investigation after an incident where liquids have caused a gas turbine or gas compressor failure.

It is these liquids, and compressor oil, that are able to pass by a gas analyzer system, so a project to develop a robust, safe and continuous monitoring system for carry-over liquids and other contaminants was started nine years ago.

The project aims from the start were to:

- reduce risk to operators
- reduce the cost of maintenance
- improve production performance
- reduce gas emissions during maintenance

2.1. THE STATUS QUO

Most gas analyses operate at atmospheric pressure requiring a continuous sample of gas to be extracted from the pipe. Standards, guidelines and good practice recommendations have focused on good measurement practice, and for many instruments such as Gas Chromatographs (GCs), used to report calorific value and concentration of specific gas species, good sample preparation is crucial for accurate and robust measurements. For example, GCs have several meters of capillary tubes to separate gas species and are particularly susceptible to contamination with process liquids and heavy hydrocarbons.

There are many standards, including GPA1 standards, that recommend insertion probe design. Figure 1. illustrates that normal practice is to design the probe length so that the inlet is within the center third of the pipe cross-section, thereby avoiding any liquids that may be on the pipe wall as it is essential that these analyses continue to function for long periods without maintenance. In addition, liquid and particle filters are part of the sample conditioning system to ensure that the analyzer is not exposed to any liquid or particulate contamination.

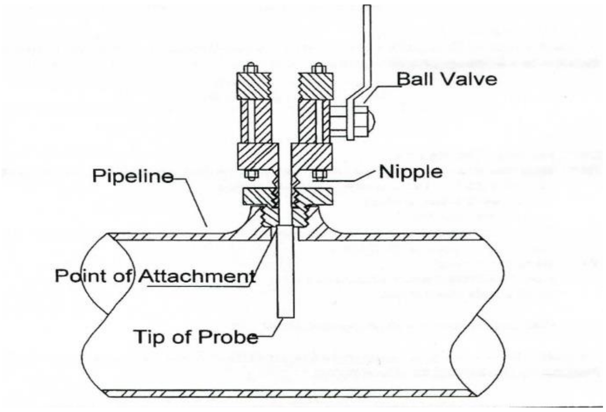


Figure 1: GPS Standard for insertion probe for sample extraction for a gas chromatograph

Liquids can be present in gas flows at a variety of droplet sizes. When condensation occurs due to a drop in temperature, very fine droplets (around 1µm) appear. If liquids are being introduced to the gas via an atomized spray, droplet size can be around 100µm. As droplets travel down the pipe they can agglomerate. When a droplet hits a dry pipe wall it tends not to bounce off 2. It forms a film on the pipe wall which slowly moves along the pipe. In smaller diameter pipes (up to 3”), there may be sufficient kinetic energy (depending upon the velocity) in the gas flow to maintain the liquid in full annular flow around the pipe wall. A larger diameter is less likely to maintain full annular flow and the liquid film makes its way to the pipe floor to form a stream, or stratified flow. In tests it was surprising how quickly an atomized droplet stream of octane “disappeared” on to the pipe wall. If sufficient liquid is present to keep the walls wet, there is more of a tendency for droplets to bounce off the pipe wall and an aerosol can be maintained.

It follows that with any liquid present a percentage of the liquid present will be on the pipe wall, and due to the highly variable nature of flow regimes, it is unlikely that analysis of a fluid from a sample probe will fully represent the amount of liquid in the pipe. It is necessary to monitor the pipe wall conditions just as much as the aerosol entrained in the gas flow.

3. THE NATURAL GAS JOURNEY

From the gas well to the point of use, liquid entrainment is the major cause of gas system upsets and plant failure. At several points, liquids are injected and then removed. However, liquid/gas separators do not perform 100% efficiently 100% of the time and liquid carry-over continues to cause $ Millions damage every year. As can be seen in Figure 2. liquid separators are in operation across the upstream, midstream and downstream sectors. It is essential that their efficiency is monitored in any gas related process if operational excellence is to be achieved.

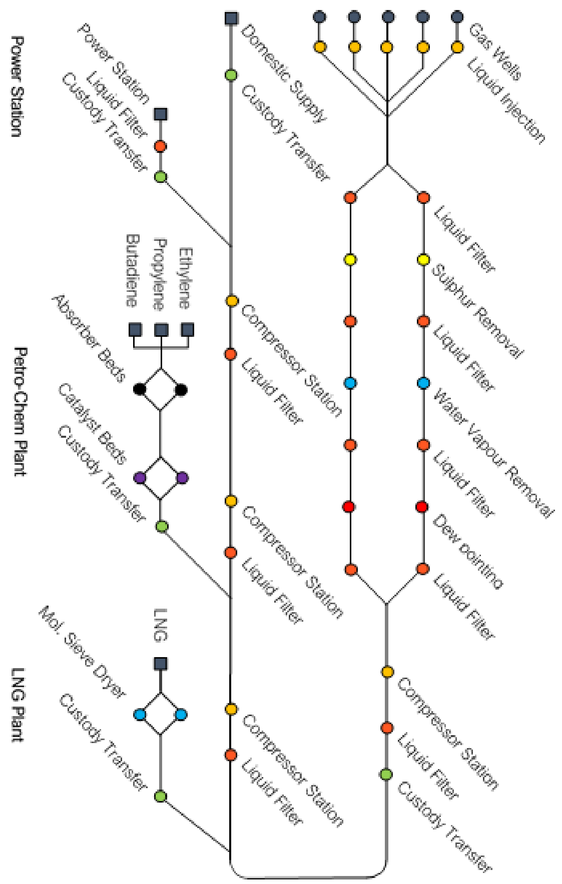


Figure 2: The gas journey from gas well to point of use

3.1. AT THE GAS WELL

Operations at the gas well may include the removal of gross amounts of liquid, but the gas remaining is still at the point of saturation (dew point) with regard to both water and hydrocarbon. Even small changes in pressure or temperature will result in further liquid dropout. In addition, as fluids at the wellhead may be saturated with water and contain high levels of Sulphur, corrosion and hydrate formation are major concerns. There have been many instances where hydrates have blocked pipelines, effectively shutting wells in and causing loss of production until expensive remediation activities can safely remove the blockage. Research also indicates that hydrate formation can also be the initiator of internal corrosion 3. It is therefore necessary to inject a hydrate inhibitor, usually monoethylene glycol (MEG) or methanol, and a series of corrosion inhibitors. In a recent investigation undertaken by Nexo Solutions, around 50 species of chemical were found in the gas entering the gas treatment plant.

3.2. GAS TREATMENT

3.2.1. GAS TREATMENT PLANT SURVEY

It is important that all liquids are removed during the gas separation process as the gas enters the treatment plant. There are many gas treatment plants around the world, and the worldwide figures published in Oil & Gas Journal 4 in 2015 are shown in Figures 3, 4 & 5. give a good baseline for further work. It should be noted, however that detailed data from Russia is not included here, but estimates at this time are that, in addition to its domestic requirement, Russia exported around 12% of the world’s gas resource. The combination of Canada, USA and South America formed 87% of the world gas treatment plants and 59% of the world's production (excluding Russia). Figure 3. illustrates the total number of gas treatment plants within a region. Figure 4. illustrates the total production capacity in that region in terms of MMscf/d. Figure 5. shows the average size of gas treatment in each region.

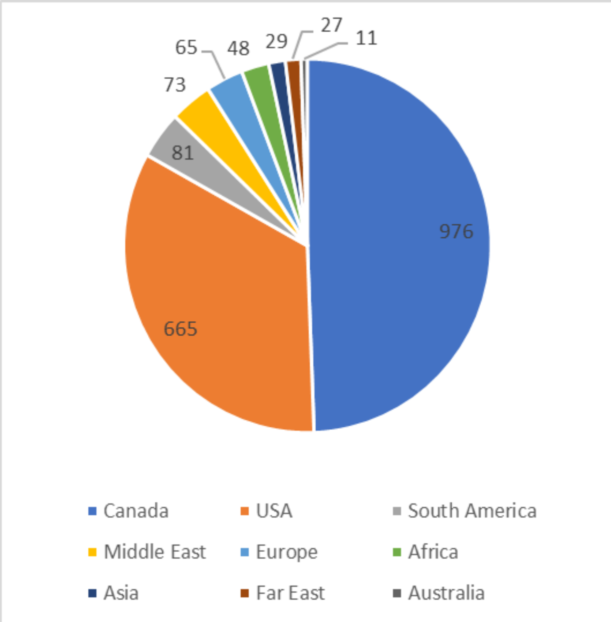


Figure 1. Number of gas treatment plants

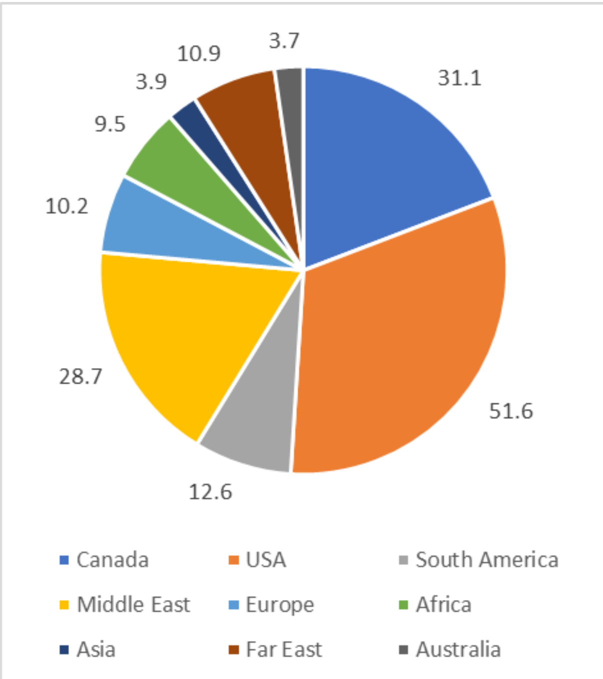


Figure 2. Gas production (billion scf/day)

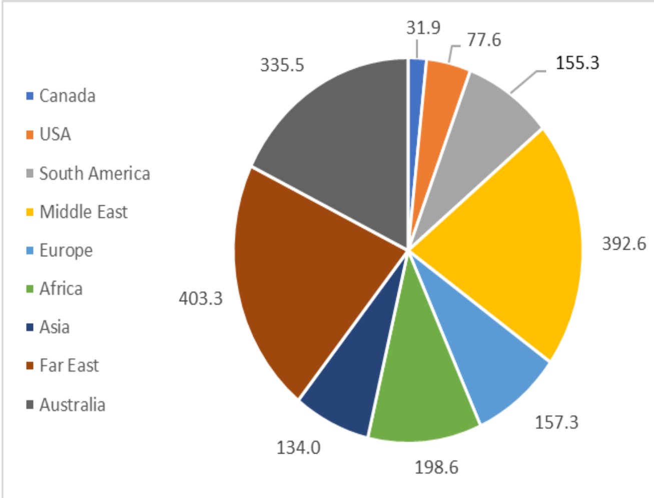


Figure 5. Average size production level (MMscf/day)

While Canada has a high number of gas plants, the average size of the plant is relatively small, while the Middle East has fewer, much larger, plants.

3.2.2. LOSS OF PRODUCTION

There are differences between plant capacity and plant production in the 2015 survey4. While some "headspace" is to be expected, the percentages in Figure 6. could indicate that many gas plants are underperforming in relation to their total capacity. This is particularly relevant as 2015 was the middle of the oil crisis when extra production would boost site profitability over fixed overheads.

	Capacity BNscf/D	Production BNscf/D	Capacity Overhead BNscf/D	Production as % of Capacity
Canada	50.7	31.1	19.6	61%
USA	89.1	51.6	37.5	58%
South America	18.9	12.6	6.3	67%
Middle East	42.5	27.3	15.2	64%
Europe	22.0	10.2	11.8	47%
Africa	18.1	9.5	8.5	53%
Asia	5.4	3.9	1.5	73%
Far East	14.0	10.9	3.0	78%
Australia	5.9	3.7	2.2	62%
	331.9	**209.6**	**106.5**	**67%**

Figure 3. Production as a proportion of capacity

While political and economic factors come into play, Europe, USA and Africa are considerably below the worldwide average of 67% of capacity.

The question should be asked, how much of the gap between capacity and production is due to underperforming gas plants?

In a survey of 148 production failures in natural gas amine plants undertaken by Amine Experts5, it is clear that foaming is a large problem. The largest cause of plant failures (31%) in the survey is due to foaming, resulting in expensive losses of production. 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 their occurrence is shown in Figure 7.

Gas Plants		
Failure	**Frequency**	**%**
Foaming	46	31%
Product Quality	42	28%
Corrosion	37	25%
Flooding	12	8%
Amine Loss	11	7%
Total	**148**	**100%**

Figure 7. Number of failures of amine desulphurisation gas plants

Numerous papers from the GPA GCC Conference in 2018 report foaming, with one site reporting around 15 foaming events per month making an average loss of production of 20% prior to plant improvements. The 20% loss of production figure is reflected in data from Nexo Solutions in the USA, putting foaming as the major cause of loss of production.

The figures above were reported from sites that were having particular problems so, in this study, the examples below use a loss of 5% to be prudent figure to represent an average plant.

The tables in Figure 8. show examples of the average size gas treatment plant in the USA and the Middle East from Section 3.2.1.

Average Sized Gas Treatment Plant in the USA			
Average Production per plant in USA		78	MMscf/D
The average loss of production due to foaming 5%		3.90	MMscf/D
Cost of Gas	$	3.28	MMBTU (Henry Hub)
	$	3.40	Mscf
Loss in Production	$	13,246	per day
	$	92,722	per week
	$	402,898	per month
	$	4,834,776.02	per year

Average Size Gas Treatment Plant in the Middle East			
Average Production per plant in Middle East		360	MMscf/D
The average loss of production due to foaming 5%		17.98	MMscf/D
Gas prices	$	3.28	MMBTU (Henry Hub)
	$	3.40	Mscf
Loss in Production	$	61,064	per day
	$	427,446	per week
	$	1,857,354	per month
	$	22,288,252.20	per year

Figure 8. Examples of foaming costs in average sized treatment plants

3.2.3. WHAT'S NORMAL?

This is a question that was asked regarding the quantity of liquid carry-over at the start of the development project to develop a liquid carry-over detection system. Inevitably the answer is "it depends". Tariffs and regulations normally require that sales quality gas should be "free from liquids and solids". Some contracts go further and require that the gas should be "commercially free of liquids and solids". The UK Gas Safety and Management Regulations (GSMR) state:

"[gas] shall not contain solid or liquid material which may interfere with the integrity or operation of pipes or any gas appliance (within the meaning of regulation 2(1) of the 1994 Regulations) which a consumer could reasonably be expected to operate."

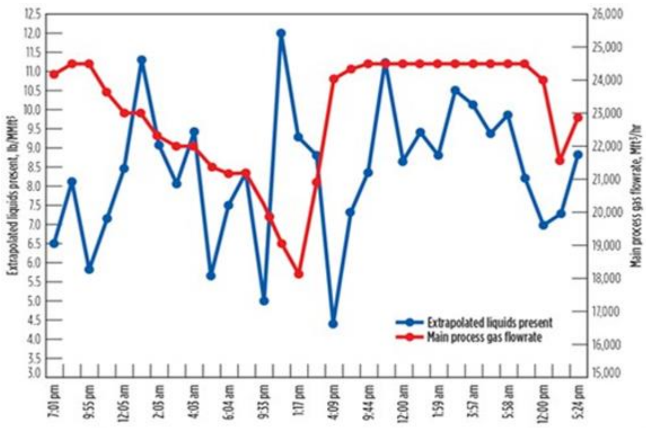


Figure 9. Test results from LNG plant 5

A detailed study, performed by Nexo Solutions, at an LNG plant was performed, as the client reported damage to molecular sieve (mol. sieve) beds due to liquid carry-over. Liquid flows were monitored at the exit from the amine unit using a slip-stream method with a high efficiency coalescing filter. Liquids flow in the slipstream were extrapolated to estimate the liquid flow in the main gas pipeline. Figure 9. illustrates the relationship between gas and the extrapolated liquid flow rates in the main pipeline.

Gas flow was varied during a 24 hour period and then stabilized at 24,500 Mscf/Hour. It can be seen that during this period liquid carry over averaged around 10 lbs/MMscf. This is equivalent to 1.2 USGal/MMscf. Meaning, if this tread continued, up to 642 US gallons (2,431 liters) per day could carry over to the downstream equipment.

There are many separator and filter designs on the market, many of which have specification quoted in a number of different ways: 0.01 or 0.1 USGal/MMscf is a common specification; another communally used specification is 1 PPMw, or some high specification filters are 2 PPBw.

For example: Figure 10 Illustrates a separator performance of 0.1 USGal/MMscf, an 8” pipe with gas travelling at 15 m/sec (33.5 miles/hour). Converting this specification, it can be seen in Figure 10. that at 20 Bar the specification relates to 8.5 ml/min and at 70 Bar it relates to 32 ml/min.

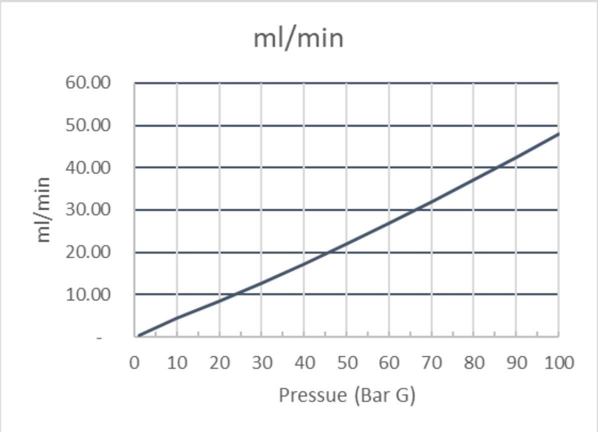


Figure 4. Separator specifications

Real world separator performance can vary dramatically depending on the design, temperature and maintenance history of the separator. A comparison of liquid carry-over flows for a variety of common separator specifications are illustrated when applied to the plant in the study7 in Figure 11.

Equivalent separator specifications applied to example plant: 588 MSF/day at 50 Bar G (725 psi)			
	lbs/MMscf	USGal/Day	Litres/day
Study result	10	981	3,714

	Separator Spec.	Equivelant US Gal/day	Equivalent Litres/day
PPMw	0.002	0.02	0.08
PPMw	0.01	0.10	0.39
PPMw	1	10.2	38.6
USgal/MMscf	0.1	58.8	223
USgal/MMscf	0.01	5.88	22.3
PPMw	50	510	1,932
PPMw	500	5,105	19,323
PPMw	1000	10,209	38,647

Figure 11. A comparison of performance found in the study and separator specifications when applied to the same plant

Being able to continuously monitor the separator outlet has clear advantages, particularly as the optimum flow rate for a separator may change depending on a variety of short term and long-term factors. In addition, if, once any separator problems have been resolved, there is still an occasional carry-over event, with detailed knowledge of the contamination event, operators can start adding anti-foam agent before foaming becomes a problem that will hinder production or gas quality at the exit of the system.

3.2.4. LIQUID TYPE

In the UK network it is unlikely that free water would be present without dew point meter alarms being tripped. Water bound with glycol carry-over is more likely and Figure 12. shows the result of routine pigging that removed around 100 liters of liquid from the National Transmission System (NTS) that was found to be mainly TEG. This level of liquid can damage gas compressors and gas turbines.

Figure 12. UK NTS routine pigging found ~ 100 litres, mainly TEG

There have been many investigations into contamination at the gas feeds to gas treatment plants. There are many more chemicals that could be additives at this point for example wax inhibitors, biocides, corrosion inhibitors, H2S scavengers. Many of these act as foaming agents or emulsifiers, and carry-over of these surfactants can be directly linked to foaming in amine and glycol processing systems which can lead to gas leaving the gas treatment phase with high H2S content or high H2O content and to loss of amine or glycol. Surfactants can increase both foaming tendency (the ease with which liquid film will encase gas bubbles) and foam stability (the likelihood that a gas bubble will resist rupturing).

It is common practice to add antifoam agents when a foaming incident occurs, but the effectiveness of antifoams can be questionable, as some amine units using antifoam experience little to no effect in foam reduction.

When antifoam is used daily, it brings short-term benefits but also long-term harm to the amine solvent. Antifoams should be considered as treating the symptoms. However, while a useful tool, finding and resolving the cause of foaming is the best method.

3.2.5. DEW POINTING

Very often condensate recovered from natural gas feeds achieves a higher price than the gas. Once the gas has been dried, dew pointing systems reduce the temperature of the processed gas to sub 0°C, very often reaching -20 to -30°C. If glycol is carried over from the dehydration unit, it will freeze at around -6°C (depending on its water content). This can lead to blockages and temperature instability in the exit gas leading to condensate/glycol mix being present in the export gas. The operator is losing condensate and the gas customer could reject the gas or fine the supplier as contaminated gas has entered the transmission system.

4. CUSTODY TRANSFER POINTS

At a custody transfer point, gas flow, pressure, temperature and quality are carefully monitored. As fiscal measurements, the uncertainty of measurement must be minimized. The introduction of the Sarbanes-Oxley Law8 has focused the minds of CEOs who can be personally liable if due diligence on fiscal measurements has not been performed to ensure that transported gas is accurately reported.

It is well known that both differential pressure and ultrasonic type flow meters will read in error if calibrated for dry gas but wet gas is being shipped. Normally acceptable accuracies for fiscal measurements are <+/-1%, but, if liquid is present, even at relatively low levels, flow meters will over read7. If the liquid flow rate is known, a correction factor can be used but, in the field, there is currently no way of checking if the gas flow is wet or dry.
Examples given in Effect of Wet Gas Flow on Gas Orifice Plate Meters paper 9 indicate that errors rapidly get to around 3 to 5% with an orifice plate meter, and in Comparisons of Ultrasonic and Differential Pressure Meter Responses to Wet Natural Gas Flow 10 higher uncertainties are reported for ultrasonic type flow meters.

The effect on the cost to the customer, based on the average size gas treatment plant in the USA (784 MMscf/day), is illustrated in Figures 13 & 14.

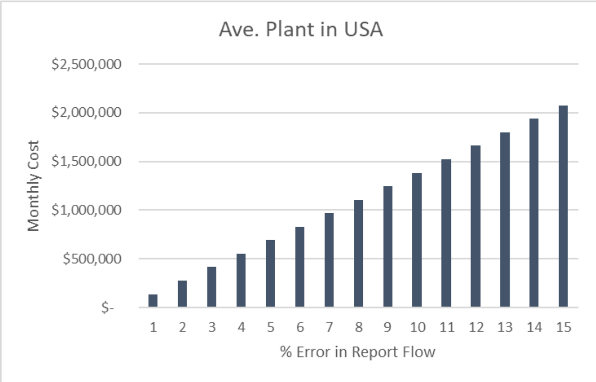


Figure 13. Cost of error in reported flow based on the average size plant in the USA

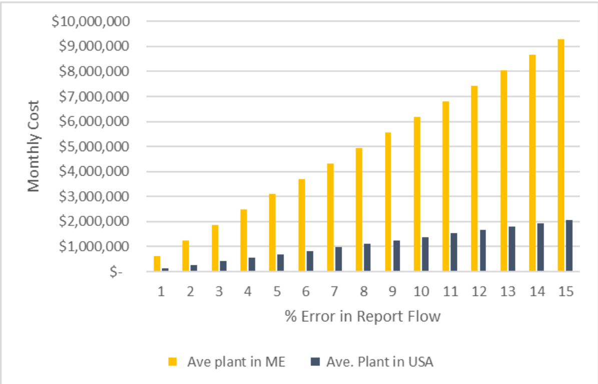


Figure 14. Cost of error in reported flow based on the average size plant in Middle East compared to the USA

5. GAS TRANSMISSION

Assuming that liquid carry-over in the export line has been minimised, a low level but continuous liquid flow will travel slowly through the pipeline and accumulate at low points. Figures 15 & 16 illustrate the elevation changes on the Trans-Anatoline Natural Gas Pipeline (TANAP)11.

Figure 15. Elevation changes provide "pockets" for liquids

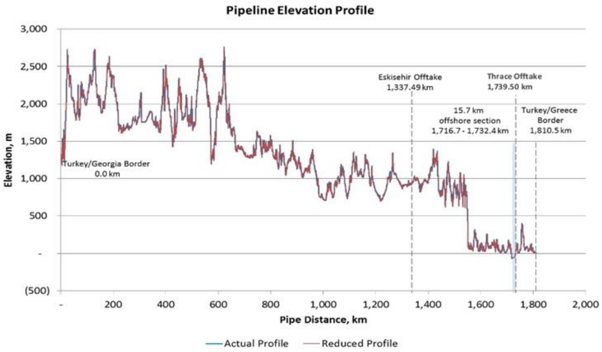


Figure 5. Trans Anatolian Natural Gas Pipeline elevation profile

Once on the pipe wall, the liquid moves down the pipe at low speed due to friction with the gas flow. It is common for liquids to pool at a low level when sufficient liquid has accumulated at a low point. It forms a slug which moves at high speed through the pipe. These slugs can be triggered by a change in flow rate or pressure and can damage the downstream plant.

12 people were killed on the 19th August 2000 in Carlsbad, New Mexico12 when a 30” diameter interstate pipeline ruptured. The pipeline pressure at the time of the accident was 675 psi (46.5 Bar G) about 80% of its maximum working pressure. The Safety Board therefore concludes that the corrosion that was found in the line at the rupture site was likely caused by a combination within the pipeline of microbes and such contaminants as moisture, chlorides, O2, CO2, and H2S.

Figure 17. Photos from the rupture site and the NSTB

One of the actions required by the investigating team was;

"Revise 49 Code of Federal Regulations Part 192 to require that new or replaced pipelines be designed and constructed with features to mitigate internal corrosion. At a minimum, such pipelines should (1) be configured to reduce the opportunity for liquids to accumulate, (2) be equipped with effective liquid removal features, and (3) be able to accommodate corrosion monitoring devices at locations with the greatest potential for internal corrosion."

Regular pigging is necessary on many pipelines which should contain sales quality gas.

6. PIGGING

Many gas pipelines have normal gas velocities of 15 to 35mph (15.6 m/s) with a maximum velocity of 20 m/s. Transmission pipelines tend to be large diameter (10"- 56") pipelines covering long distances. The usual procedure for pigging is to reduce pressure and flow to suitable levels to allow the cleaning pig to run close to its optimum cleaning speed usually around 11 mph (5 m/s). From an operator perspective this is a costly exercise, as flow often has to be reduced for a number of days and takes further time after pigging to regain normal pressures and flows. Extensive planning is required, and the pigging operation leads to lost revenue from the reduced gas flow.

Pipe diameter (inches)	Normal capacity (MMscf/day)	Capacity when pigging (MMscf/day)	Difference (MMscf/Day)	Cost of pigging per day
8	734	269	465	$ 1,578,697
10	917	336	581	$ 1,973,372
12	1,101	404	697	$ 2,368,046
24	2,202	807	1,394	$ 4,736,092
30	2,752	1,009	1,743	$ 5,920,115
36	3,303	1,211	2,092	$ 7,104,138
40	3,670	1,346	2,324	$ 7,893,487
44	4,037	1,480	2,556	$ 8,682,835
48	4,404	1,615	2,789	$ 9,472,184
51	4,679	1,716	2,963	$ 10,064,195
56	5,137	1,884	3,254	$ 11,050,881

Figure 18. The cost of pigging per day for different pipe sizes. All data is for a gas at 50 Bar G with a velocity of 30 mph for normal operation and 11 mph while pigging.

7. LINEVU

7.1. CONCEPT

It was clear that a system able to detect levels of liquid in gas pipelines that may be susceptible to carry-over, and therefore pigging, should not protrude into the pipeline. Also, many pipelines are buried at the point that a monitor is required. While a pit could be dug, this adds to the installation cost. If a system could be designed to use existing tapping point flanges it would be easier for operators to install (Figure 19.). This led to research using laser systems to monitor the depth of liquid which, while very sensitive to small amounts of liquid, the response of the system was not stable enough to determine the quantity of liquid present.

Figure 19. LineVu system mounted on top of a pipeline

A video system was devised using image processing to create an alarm if contamination is detected. This proved to be very sensitive to small droplets and gives the operator the option to see the pipeline activity. This feature provides operators with confidence that the detection system is operational, and they can make a judgement on what level of contamination is acceptable.

7.1.1. SAFETY

Safety is the primary concern with all equipment attached to pipeline networks, and so LineVu has undergone several iterations of the design of the devise mounted on the gas system (Camera Can). All connections, electrical and mechanical, are made within a standard Class 900 3" RTJ flange, making the main connection an industry standard for fugitive emissions and safety calculations.

Figure 21.
The Camera Can

Figure 22.
Camera Can
with Window Puck

Figure 22.
Camera Can
with illumination

The camera and illumination assembly are mounted on the Window Puck (Figure 20.). The Window Puck houses 4 illumination ports and one camera port. All ports house a pressure retaining sapphire window. Pressure testing from a systematic view point has been performed at over 700 Bar G (10,152 psi) without damage. Each Window Puck is tested to 221 Bar G (3,250 psi) prior to assembly.

The Window Puck assembly is inserted into a secondary containment chamber in the Camera Can body, ensuring that, if there is 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 two pressure tests, one for the upper chamber to comply with certification and the same pressure test as the Window Puck on the lower chamber.

Once assembled, a final pressure test is performed on the complete Camera Can.

7.1.2. COMMUNICATIONS

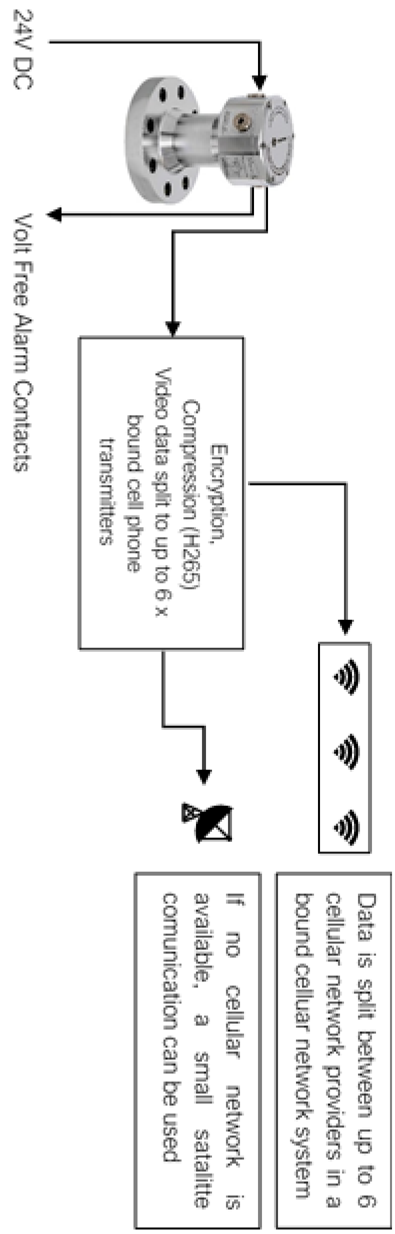
Security of the client's network has been considered a priority, and the communication system designed accordingly. Several levels of security are in place between the Camera Can and the operator.

There is no direct connection to the client's network (other than a local volt free alarm relay) thereby overcoming security issues of opening ports in the client's network.

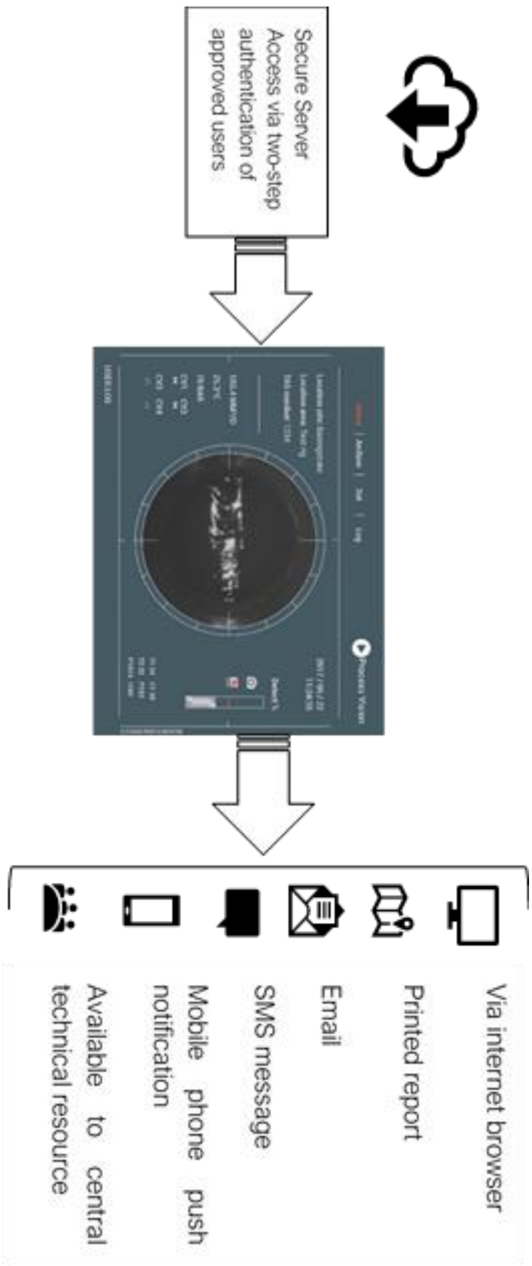
Video data at the Camera Can is compressed, encrypted and split between up to six cellular data transmitters and sent to a high-security cloud platform. As the data can be split among different network providers, it makes the encrypted data more difficult to hack. Only date, time and serial number are burnt onto the video prior to leaving the Camera Can thereby making the data anonymous.

Once on the secure platform, data is presented on an encrypted viewing platform with two-step verification for approved operators and service personnel.

On-site system



Receiver and User Interface



When several cameras are installed on a network, the network map can be generated on the user interface with nodes for each LineVu where network controllers can view pipeline activity at any of the locations.

When a contamination event occurs, an alarm is automatically generated and video is recorded. It is likely that both local and remote engineers will need access to the data in the alarm condition.
A number of actions can be taken upon an alarm condition including:

- volt free relay activation
- SMS texts
- email
- push video notifications
- push still shot notifications

8. NATIONAL GRID

National Grid in the UK is the first transmission system operator to trial the LineVu system13. Results will be made available to all network licensees and, assuming the trial is successful, will be adopted as a “business as usual” system for monitoring liquid in the NTS.

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