PROCESS INSIGHT SOLUTIONS

MAY 2022

MONITORING COMBUSTIBLE AND TOXIC GASES

CONTROLLING YOUR NATURAL GAS BURN

CLAMP-ON ULTRASONIC GAS FLOW METERS

GAS MOISTURE ANALYZERS: WITH J22, THE NEXT GENERATION IS ARRIVING

Canadian PROCESS EQUIPMENT & CONTROL NEWS

Accurate gas measurement is critical in a wide variety of challenging applications including detection systems, emissions, and separation processes.

Process managers are confronted with a wide range of tools in gas management from optical gas imaging to continuous emissions monitoring systems and instruments that are now capable of measuring multiple variables including mass flow, density, and temperature.

Canadian Process Equipment & Control News' Gas Measurement Handbook explores the latest solutions and benefits now available for 2022.

INDUSTRIAL AUTOMATION
Process Insight Solutions

MAY 2022

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ANNEX BUSINESS MEDIA

MONITORING COMBUSTIBLE AND TOXIC GASES IN INDUSTRIAL ENVIRONMENTS

In survival situations the rules of three apply: three weeks without food, three days without water and three minutes without air – are all deadly. Clean air is vital for human health and must be stringently monitored in industrial environments where toxic, corrosive, asphyxiant and combustible gas hazards are common.

In food & beverage plants anhydrous ammonia is used as a refrigerant, hydrogen sulfide can accumulate in sewage systems of wastewater treatment centers and carbon monoxide from engine exhaust fumes can accumulate in fuel tank filling stations. These are all examples of toxic gas hazards that can be monitored using electrolytic sensors that we will cover in this article. Toxic gasses are all gasses that are harmful to living things. Safety is paramount, and it is absolutely necessary to monitor these gases when exposure is likely. While Fixed Gas Systems don't directly contribute to the bottom line they do add significant value by protecting your assets and ensure onsite workers make it home safely.

Gas Detection Systems

Gas detections systems are put in place to alert workers of hazardous conditions such as toxic, corrosive and asphyxiant gas reaching harmful concentrations and combustible gas leaks reaching their lower explosive limit (LEL).

Sensidyne Fixed Gas Detection systems consist of a sensor and transmitter which is installed in a fixed location in close proximity to the potential hazard source. Transmitters remain fixed and do not require preventive maintenance, but the sensors are consumable and require periodic calibrations or replacement once the sensor has reached the end of its life. In an event of a gas leak the transmitter will provide signaling to the gas detection system, which in turn will engage sirens, horns and any automated functional actions that are integrated in the sites Distributed Control System (DCS.) As with any complex engineering system there are challenges with ensuring your system functions as intended and meets the regulatory codes within your facility. At Sensidyne our experts and engineers are professionally trained and accomplished to guide your selection to ensure your Gas Detection needs are met.

Asphyxiant and Toxic Gas Hazards: Electrolytic Sensors

An Electrolytic sensor consists of a stack of electrodes and wetted electrolyte filters. One electrode is exposed to the air and two other electrodes are encased inside surrounded by hydrophilic separators and electrolyte solution. The electrode exposed to air is called the working electrode and is optimized for an oxidation or reduction reaction to occur depending upon the target gas. These sensors are utilized to detect the presence of toxic gas and are also use to monitor oxygen levels.

Another hazard that can occur in industrial environments is asphyxiation caused by low oxygen levels. This working electrode reacts when it comes into contact with a target gas, reacts and generates a current that is linearly proportional to the fractional volume of the target gas. These sensors have a lifespan of typically two years so an inventory management system should be considered to ensure spare sensors remain viable for use. Our universal transmitters keep track of the sensor life and can be configured to send an alert when the sensor is starting to reach the end of its life. Our transmitters can also be configured to go into a fault state when the sensor requires calibration, which allows the maintenance team to plan ahead appropriately and avoid any potential unscheduled downtime.

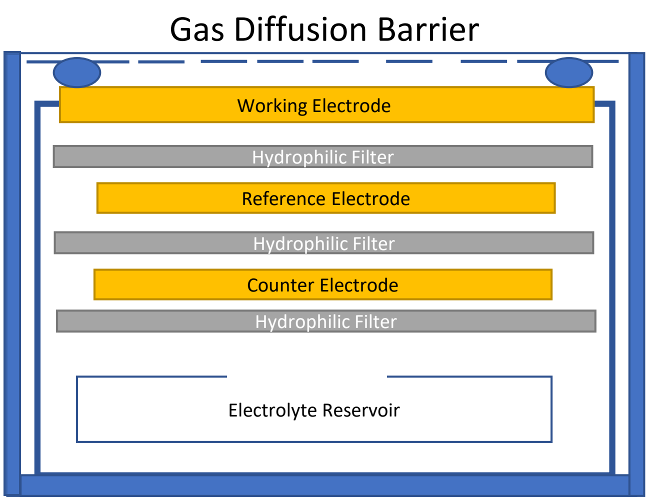

Figure 1: Electrolytic cell

Combustible Gasses and CO2: Infrared Sensors (IR)

IR sensors utilize Infrared Spectroscopy, the study of how molecules interact with infrared light to discern information about its chemical bonds. This method is commonly used in labs to analyze and determine all sorts of molecular species. This method is particularly effective with sensing the hydrocarbon gasses that are found in oil & gas plants. Another advantage IR sensors have is that they are not susceptible to being poisoned as is the case with catalytic bead sensors. IR sensors are not limited to combus-

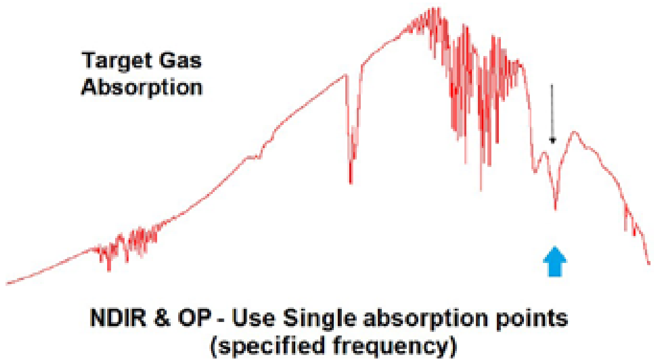

Figure 2: Infrared Spectroscopy Readings

tible gasses however, Sensidyne carries IR sensors for CO2 gas which is inert and would not be detected with electrolytic cells or catalytic bead sensor.

Photoionization: Volatile Organic Compounds

The presence of volatile organic compounds (VOCs) is growing concern for industrial complexes, exposure to these hazardous substances care detrimental to human health. Photoionization is the most common technique used to sense VOCs. A photoionization detector, "PID" for short, is composed of an ultraviolet light source and sensor. Any present VOC molecule is will ionize while exposed to UV radiation. After exposure an electron is released, this free electron is detected and measured by the electronics imbedded in the sensor. Each compound has a unique "Ionization Potential (IP)" value measured in electron volts (eV). This specific IP value is used to determine the eV rating of the lamp in the sensor which will filter out any unwanted interactions form other VOCs.

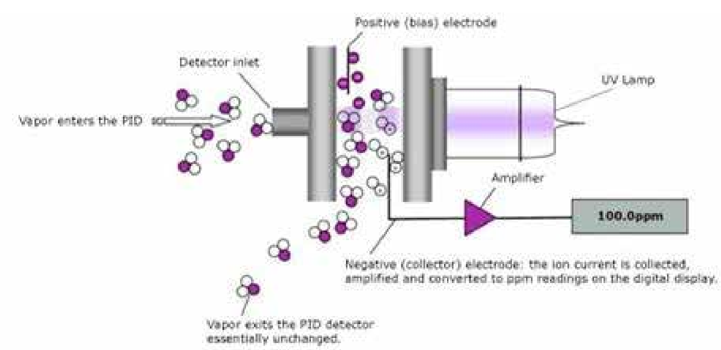

Figure 3: Photoionization Detector

Combustible Gases: Catalytic Bead Sensors

Catalytic bead sensors fall under the family of gas sensors known as pellistors; this term is an amalgamation of word pellet and resistor. This technology has been around for more than half of century and originally developed for the use in mining operations. Previous to this invention by the British scientist Alan Baker, miners used canaries to determine the presence of methane in mining shafts – if the canary died, then methane was present at a toxic level (and hence the phrase "canary in a coal mine"). The sensor is composed of a heated metal oxide catalyst that will oxidize a combustible gas; the heat generated by this reaction causes a change in resistance of the element. This resistance change is proportional to the gas concentration. The operating principle has been proven to be reliable and effective although there are some caveats. Exposure to hydrogen sulfide, styrene, polymers or any substance that forms thin films under heat may poison or inhibit the sensor. When such substances are present it is best to consult with a sales engineer to assist with selecting the proper detection, in many instances an IR sensor might be needed.

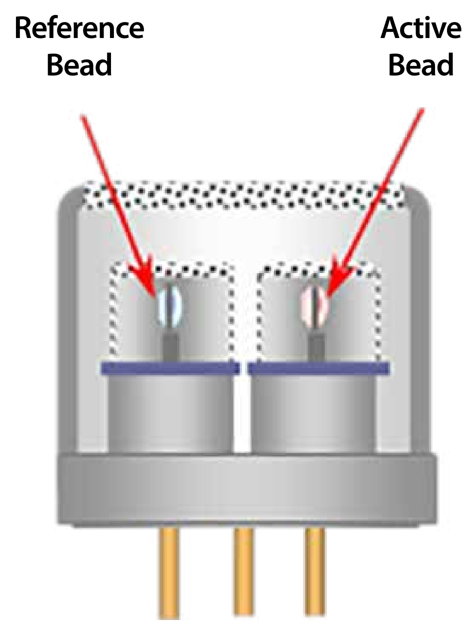

Figure 4: Catalytic Bead Sensor

Lower Explosive Limit

The Lower Explosive Limit (LEL) is the lowest concentration of combustible gas in air that is capable of producing a flame in the presence of an ignition source. It is represented by a percentage not a concentration since the LEL concentration by volume varies from gas to gas. Typically, when the LEL gas is not methane or propane, a K factor is programmed into the transmitter to tune the detector to the specific target gas. In cases where multiple combustible gases are present, the sensor should be programmed to highest K factor (the least sensitive gas) to achieve the safest configuration. It is worth noting that in this configuration the LEL% reading for the other gases will respond higher than the actual LEL concentration. The LEL varies between combustible gases, methane for example has an LEL concentration of 5% by volume in air, which the transmitter will display as 100% LEL. 0% LEL would indicate a gas concentration of 0% vol.

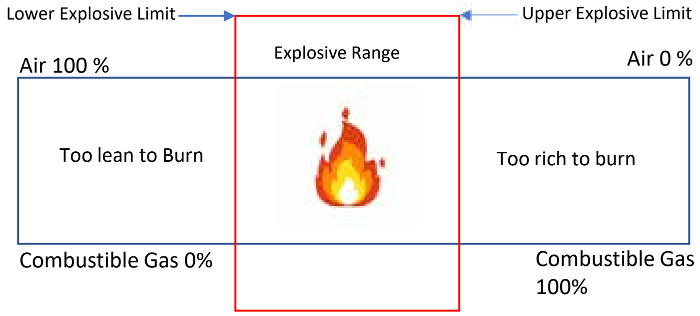

Figure 5: LEL Range

Transmitter

The transmitter interprets the output from the sensor and displays the reading which then can be communicated to the control system, typically a controller that manages alarms, strobes and functional actions. The most common output for the transmitter is analog 4-20mA, but we also offer MODBUS, HART, BacNet and relay options. The selection of your transmitter will be determined by the hazardous area classification, communication protocol and budgetary requirements. There are some transmitters such as the SensAlarm FLEX in Sensidyne's catalog with a fully integrated with alarm/ strobe and relays as a true "Plug and Play" gas detection system.

Calibration

The procedure of calibration verifies and maximized the accuracy of the sensor by comparing the instrument to a known standard, the standard in this case will be calibration gas which we supply our customers. The process is expected to be part of your planned preventive maintenance schedule. Our sensors are calibrated at the factory but do require calibration upon arrival. The environmental conditions that the sensor is calibrated should be the same as the area in which the sensor will be stationed. Our sensors are calibrated in Florida so a sensor installed in a higher altitude city such as Denver would need to be calibrated during its commissioning to ensure accuracy. Calibration is also recommended after a high-level reading or an extended period of constant exposure to the target gas. The gas standard is typically the same as the target gas and is used at half of the sensor full range for almost all toxic gases. When it comes to combustible gases propane or methane are used as surrogates and a K factor is applied at the transmitter when the target gas is not the same, which is a mathematical correction factor.

K Factors

Both IR and Catalytic bead sensors interact with multiple combustible gases so the appropriate corrective K factor will need to be programmed onto the transmitter when the specific target gas

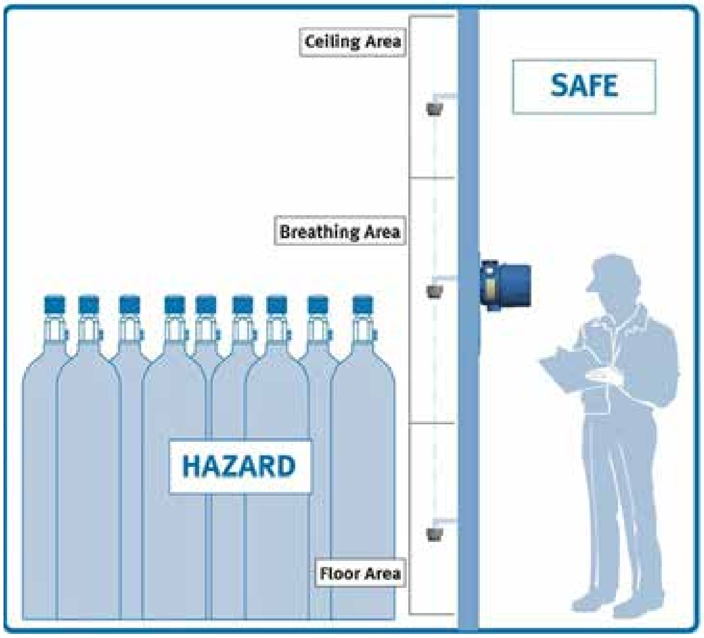

Figure 6: Remote Sensor Placement

is not used as a calibration gas standard. This means that a target gas such as Dimethyl Ether can be calibrated using methane calibration gas. A K factor list for IR and Catalytic Bead sensors can be found in the respective datasheet on our website.

Area Classification

Hazardous area classifications systems are in place to facilitate the safe use of electrical equipment in environments with the potential presence of combustible substances. The manner in which these areas are defined is dependent on the country, but the overall concept remains the same. They are mainly classified by two variables: the combustible source (Class) and the likelihood that it would be present (Division). Electronics with hazardous ratings have specific engineering controls built in to eliminate the possibility of being a source of ignition. It is imperative to know this information, failure to do so could result in unsafe conditions that could create negative consequences. Hazardous rated equipment usually comes at a higher cost. Knowing when it is acceptable to purchase a non-hazardous device will lead to savings on capital expenses.

Examples of hazardous area classifications include:
Class 1, Division 1
Class 1, Division 2
Class 2, Division 1
Class 2, Division 2
Zone 0
Zone 1
Zone 2

Sensor Placement

It's important to understand where your target gas will likely accumulate if there is a leak. Ammonia (NH3) gas is lighter than air, so sensors for NH3 should be placed higher, heavier hydrocarbons will accumulate near the ground, so those sensors should be lower. If sensing for oxygen, these sensors should be installed in the breathing zone level. The ideal location of the sensor is a location where the highest concentration is likely to occur. A sensor placed near an entryway or ventilation exhaust will be exposed to a dilute sample while other areas increase in concentration of the target gas, this could cause an unsafe work condition.

The Combustible Sensor can be remote mounted up to 100 feet (30m) from the transmitter to the ceiling area, the breathing area, or the floor area, depending on the gas hazard.

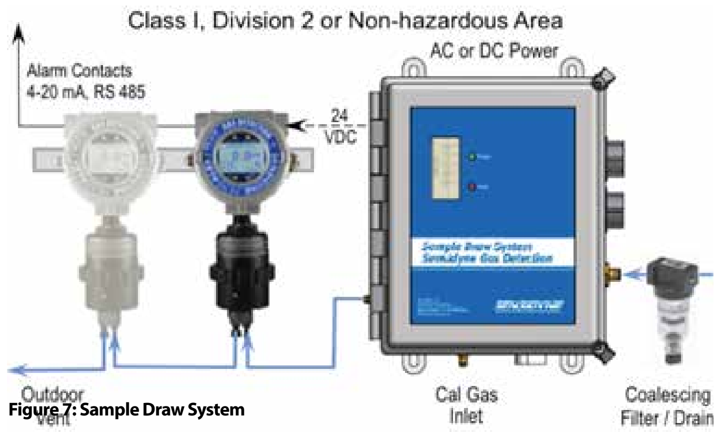

Figure 7: Sample Draw System

Sample Draw

There are cases where the optimal sensor location is challenging, such as a difficult to access deep well would require a multitude of work permits and safety protocols to access. In this instance a sample draw system would be beneficial. The sample draw is essentially a gas pump skid that would draw a gas sample from one area and feed it into a fixed gas sensor installed in a safer area. These systems allow access to hard-to-reach areas and keep maintenance workers away from potential hazards. Avoiding the need for work permits and safety gear during planned maintenance since the serviceable components of would in installed in a safe area.

Expert Guidance

Selecting an optimal Fixed Gas system to meet your needs may seem like a daunting task, but our network of friendly experts and engineers are happy to assist. Please call or email your local manufacturers representative for assistance with your questions.

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Figure 1: Natural gas process heating application

CONTROLLING YOUR NATURAL GAS BURN TO CUT FUEL COSTS AND EMISSIONS

Nearly all industrial processes and manufacturing operations rely on natural gas as a fuel, even if it is only for plant heating, ventilation and air conditioning (HVAC).

Heavy duty industrial plant processes (Figure 1), such as those found in oil and gas, refining, chemical production and electric power generation, as well as those in the manufacturing industries, including steel, aluminum, glass and others, depend heavily on natural gas to fuel the processes used in their production.

According to the U.S. Energy Information Agency (EIA) [1], in 2020 the U.S. consumed about 30.5 trillion cubic feet (TcF) of natural gas (or 31.5 quadrillion British Thermal Units (BTUs). The primary uses of natural gas in the U.S. is for electricity generation and industrial heating, with 38% for electric power generation followed closely at 33% for use by industry, 15% for residential, 10% for commercial, and 3% in transportation. Note that electric power's share also includes the electricity consumed by industry.

"The industrial sector uses natural gas as a fuel for process heating, in combined heat and power systems, as a raw material (feedstock) to produce chemicals, fertilizer, and hydrogen, and as lease and plant fuel (Figure 2). In 2020, the industrial sector accounted for about 33% of total U.S. natural gas consumption, and natural gas was the source of about 34% of the U.S. industri-

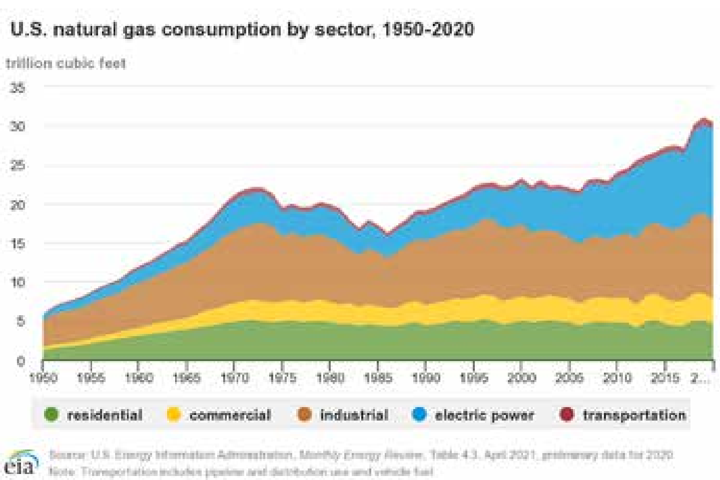

Figure 2: U.S. natural gas consumption by sector in 2021

al sector's total energy consumption." In addition, the U.S. EIA includes the natural gas used to move product through pipelines as a fuel separately under its transportation category.

The Challenges

The cost of natural gas for electric power and for industrial heating processes is expected to rise as access to supplies is reduced, while emissions controls also continue to grow more stringent. For these reasons, there is an urgent need for industrial process and manufacturing companies to optimize and more tightly control heating processes that involve burners, boilers, furnaces, ovens, kilns, dryers, oxidizers and flare stacks (as well as reduce their electric power costs).

Many process and plant engineers will be familiar with some form of the old adage, "You can't control what you don't measure accurately." Fortunately, there are many process heating best practices that can be incorporated into industrial plant operations. The one thing all of these enhancements depend on, however, is accurate, consistent air/gas flow measurement to control the burn and assure highly efficient heating.

These best practices not only help manufacturers become leaner by saving money, but they also allow them to become industry leaders in green, sustainable practices. With the U.S. Securities and Exchange Commission (SEC) announcing recently its consideration of a new climate emissions disclosure rule that would affect public companies, the U.S. could soon join other European countries already measuring and reporting their carbon footprints. [2]

Four Key Factors to Control the Burn

To reduce natural gas consumption, it is important that process and plant engineers know how to control the calorific value of their gas feed for any industrial heating process. To reach this goal, there are four key factors that engineers and technicians must consider when optimizing heating processes involving boilers, vessels, ovens, kilns, dryers, heaters, etc.

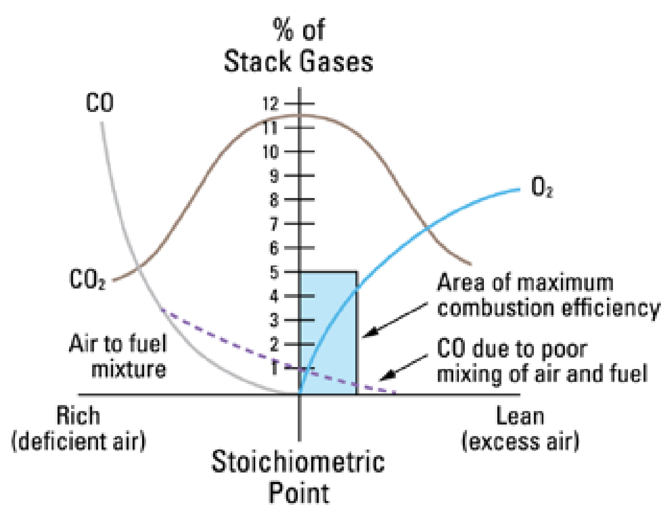

Figure 3: Stoichiometric burn process

#1 Process Stoichiometric Burn Ratio

The stoichiometric point in well controlled natural gas fired processes is where the mixture of fuel to air is optimal. Too little air, and the burner fire doesn't achieve its full calorimetric heating potential and natural gas is wasted when it takes longer than necessary to achieve and sustain the required heating levels for vessel burners or steam boilers (Figure 3).

When the fuel mixture is too air rich, then there is the potential for excess nitrogen oxide (NOx) emissions, which are a highly reactive gas and toxic pollutants. NOx often appears as a brownish gas (remember smog). It is a strong oxidizing agent and plays a major role in the atmospheric reactions with volatile organic compounds (VOC) that produce ozone on hot summer days.

#2 Effects of Gas Composition

Natural gas composition (Figure 4) differs somewhat around the world, as well as seasonally in very cold winters and hot, humid summer conditions. The primary energy components of natural gas are methane, ethane, propane, butane and condensates. The non-energy components are nitrogen, carbon dioxide, hydrogen sulfide and helium.

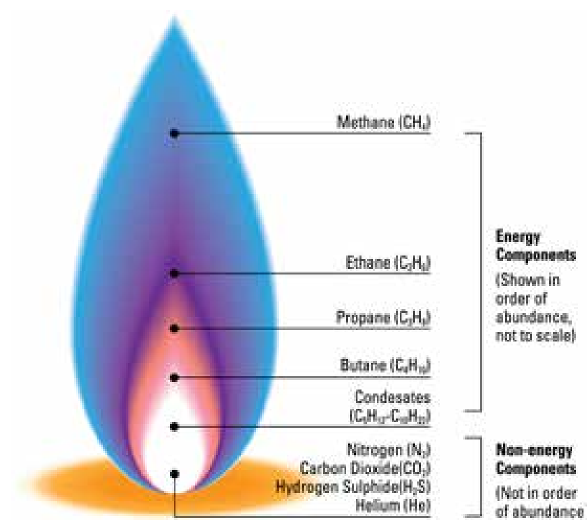

Figure 4: Natural gas composition

The mix of these components can affect gas density, the calorific value and then in turn plant instrumentation. Very few flow technologies are fully immune or easily adapt to changes in gas composition. A few volumetric flow technologies utilize a fixed gas density at ambient conditions, not taking into account pressures and temperatures that could affect mass flow readings. Some thermal flow instruments, however, are available with multiple calibration groups, which can automatically switch seasonally or any time as inline gas analyzers indicate changes in the gas mixture to assure the proper air/gas ratio is maintained for heating efficiency.

#3 Process Variability – Turndown Range

Continuous and batch processes often operate at variable levels of production, which means the amounts of natural gas and oxygen required for heating are also variable. Some of the reasons include processing multiple products on the same line, seasonal demand, wash-down cycles, seasonal planned maintenance, shift changes, etc.

For the most accurate gas and air flow measurement, a laboratory-like steady-state flow is generally the easiest to measure. That's why in actual plant installations it is important to understand the potential full flow range of the gas to be measured, also known as turndown range – from the lowest to highest flows and if the flow measurement accuracy expected will be available over the entire flow range (Figure 5).

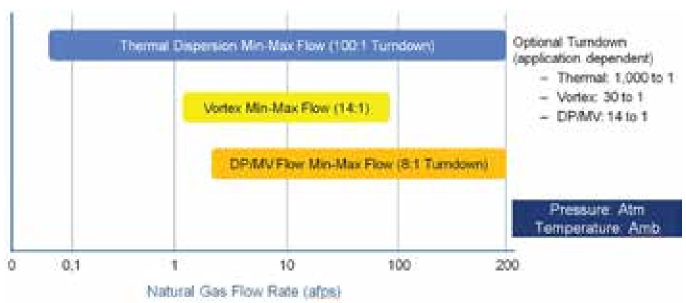

Figure 5: Turndown range

#4 Flow Meter Accuracy and Repeatability

In order to achieve the desired flow measurement accuracy level with confidence, the process or plant engineer must define the required process flow range, the desired flow measurement accuracy and the expected turndown ratio. For example, some processes require a rapid start-up with initially fast heating and then revert to a much lower steady- state or standby function in between batches. The speed of these changes in gas flow can affect measurement accuracy.

The major natural gas flow meter technologies available (Coriolis, differential pressure, thermal, ultrasonic, vortex) all vary in specified accuracy from a high of ± 0.01% or less depending on their turndown ranges from 1,000:1 to 8:1 (and depending on sensing technology). For natural gas process or plant heating, thermal flow sensing offers the advantages of a broad flow range, wide turndowns and accuracy to ± 0.75% (Figure 6). With the exception of custody transfer applications, these instruments provide a great balance between total cost of ownership and performance.

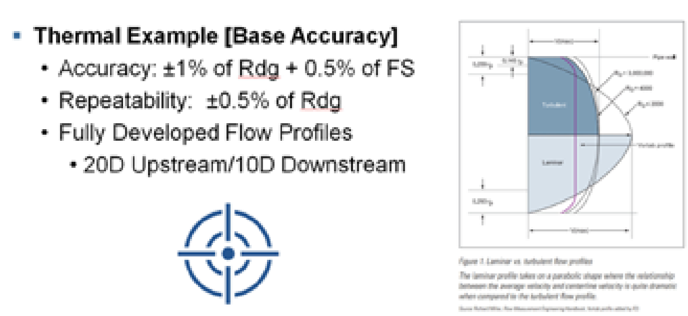

Figure 6: Flow meter accuracy and repeatability

Often Over-Looked Considerations

Confusion often results because there are the previously mentioned five different flow sensing technologies, which all can be used to measure natural gas or air. They all have their advantages and disadvantages depending on the media composition, the process application and the point of measurement. For example, coriolis, differential pressure (dP) and thermal flow sensing technologies are all used to measure natural gas.

Coriolis meters, with their accuracy of ±0.01%, would seem to be the best performance choice for any application, but their much higher cost is typically best reserved for custody transfer applications: where the higher cost is easily justified. Differential pressure, on the other hand, is a volumetric sensing technology typically used in liquids, which requires separate temperature and pressure compensation measurements to infer the mass flow rate of a gas.

In comparison, direct mass flow thermal sensing technology places two thermowell protected platinum RTD temperature sensors in the process stream. One RTD is heated while the other senses the actual process temperature. When using the Constant Power method of driving the sensor, the temperature difference between the RTDs generates a voltage output, which is proportional to the media cooling effect for determining the gas mass flow rate (Figure 7) without extra pressure or temperature transmitters required by volumetric devices to account for changes in gas density.

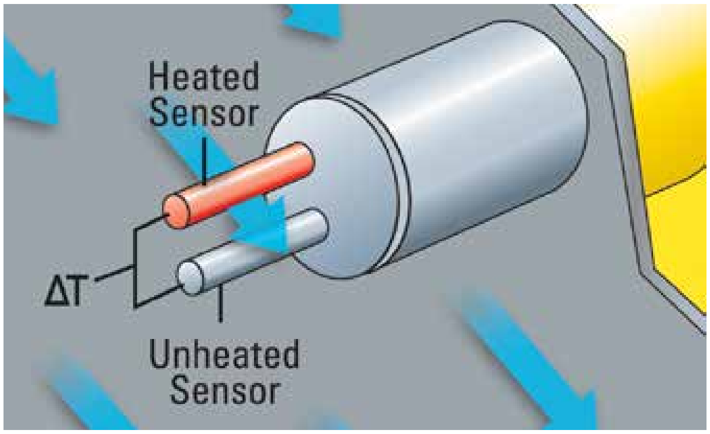

Figure 7: Thermal dispersion flow sensing

When measuring air or gas, a thermal flow meter is typically the simplest and least complicated solution. In many cases, an insertion type sensor can be used, which eliminates the need for costly bypasses required for servicing a spool piece flow element. There are no additional sensors or other electronics to purchase, install, and maintain, which can add to the total installed and lifecycle costs of an instrumentation purchase decision. These qualities speed instrument return-on-investment (ROI) too. In addition, there are no moving parts to break off for safety in natural gas pipes and no orifices to plug or foul requiring extra cleaning maintenance when recycling dirty gas for co-gen power applications.

Calibration Methodologies

When it comes to gas flow meters, it is important to ask the supplier about the type of calibration that will be performed. The industry relies on two standard calibration procedures: Air equivalency gas calibrations or laboratory gas calibrations performed under actual plant conditions. The equivalency method presumes that a substitute gas can be used in the calibration process. This methodology assumes that the thermo-physical properties of the substitute gas are similar to that of the actual gas to be measured; which is quite often not the case, especially when hydrocarbons and hydrogen are involved.

A laboratory calibration that best mirrors actual plant conditions will provide the best results. These calibrations will take into account conditions that can include variable flows, high and low temperatures, multiple gas compositions, etc. (Figure 8). The user is then presented with the calibration flow data recorded from the actual instrument calibration process that provides assurance the meter will operate accurately and dependably under installed field conditions.

Installations with Limited Footprints

When planning to optimize an existing natural gas process line, an early consideration should be the optimal location of the flow instrument. Today's legacy process and manufacturing plants are often a dense maze of piping, instruments and equipment that make installing anything new a challenge. Flow meters installed to optimize natural gas heating processes are no exception.

All air/gas flow meters typically perform most accurately and consistently in a laboratory-like environment under a steady-state air/gas flow with no disturbances. In a real plant installation, they require a minimum upstream and downstream straight pipe run of several diameters away from obstacles such as elbows, valves and blowers to achieve a disturbance-free, measurable uniform flow profile. Without the required straight-run, accurate and dependable flow measurement can be problematic depending on the actual flow disturbances in the pipe.

Figure 8: FCI calibration lab

To simplify meter installation in space restricted areas of a plant, flow conditioners are available to tame unruly gas flows for proper measurement. For example, the FCI ST75 flow meter with its optional integral Vortab flow conditioner (Figure 9) solves these issues with its uniform mixing tabs that actually straighten the gas flow prior to measurement.

Figure 9: FCI ST75 with built-in Vortab conditioner

For larger lines, spool or plate designs can be utilized with single-point thermal mass flow meters, as well as other technologies. It is important to pay attention to how the flow conditioner performs. Be sure to properly address swirling flow conditions from elbows out-of-plane that could affect measurement performance. Also, look at permanent pressure loss for the type being used to avoid wasted energy costs.

Conclusions

With supply issues, rising prices and mandated carbon footprint measurement all on the horizon, the question is not whether to optimize your plant's natural gas processes, but when is the time right to get better control of your burn. The higher gas prices go, whether because of supply, inflation or regulation, the faster the ROI payback on what is typically the modest cost of a flow meter upgrade to supporting better natural gas flow heating of your processes.

As you consider or plan the optimization of natural gas heating processes, you might want to consider the words of Rear Admiral Grace Murray Hopper, "The most dangerous phrase in the language is 'We've always done it that way'."

Learn more about FCI's natural gas flow measurement and control solutions @ **www.FluidComponents.com/natural-gas**

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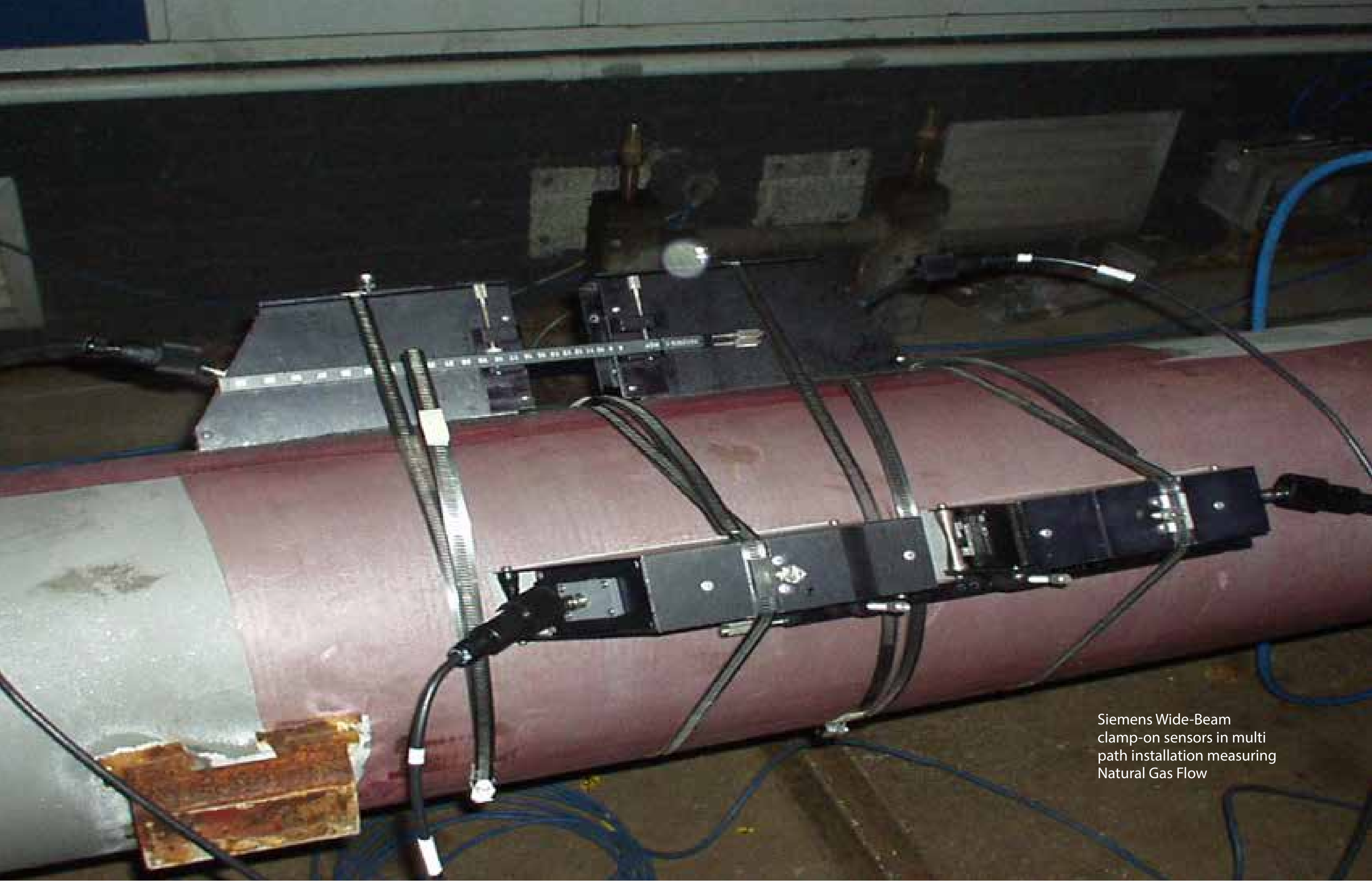

Siemens Wide-Beam clamp-on sensors in multi path installation measuring Natural Gas Flow

CLAMP-ON ULTRASONIC GAS FLOWMETERS

By Vijay Acharya, M.ENG, P.ENG

Thanks to the Wide-Beam ultrasonic transit-time measurement principle that Siemens is first to invent, and 100 Hz data update rate developed by Siemens, the SITRANS FS230 clamp-on ultrasonic gas flowmeter tolerates most wet gas conditions.

Most competing meters would be incapable of operation in such challenging environments, but the SITRANS FS230 can perform accurately even when moisture is present. Wide-Beam technology provides accuracy and reliability in numerous field installations around the world. The article also includes impact of mixtures of Hydrogen content in Natural Gas tested at DNV-GL, Netherlands on the performance of Wide-Beam sensors and FS230 flow metering system.

Siemens Ultrasonic clamp-on flow meters working on "Transit Time" principle accurately measure volumetric flow of gases. It is ideal for most natural, specialty and process gas industry applications, including:

- Check metering
- Lost And Unaccounted For (LAUF) analysis
- Allocation
- Flow survey verification
- Production
- Storage
- Gas-fired power stations

Non-Intrusive & Non-Contact

As with any other flow metering device from Siemens, it is not necessary to cut the pipe or shut down operations to install the flow meter; the sensors are quickly and easily mounted on the outside of the pipe, minimizing maintenance costs and preventing deposits from forming.

- No moving parts, so it offers no obstruction or pressure drop.
- No wear and tear or fouling of wetted parts like electrodes of electro-magnetic flow meters.

- Not affected by aggressive, corrosive, or toxic liquids or gases
- No contaminants when measuring the sterile or high-purity media.
- No dependence on the pressure, temperature, and other fluid property variations.

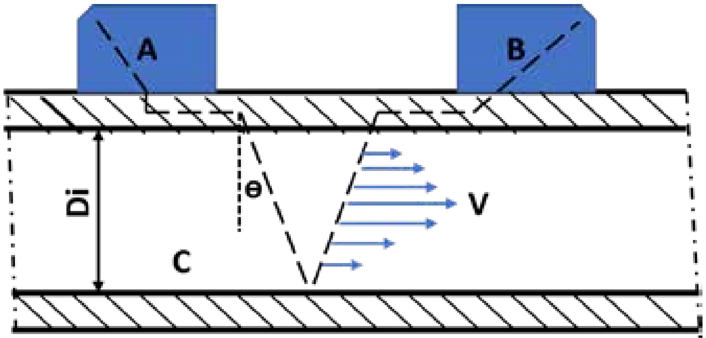

Figure 1: SITRANS FSS200 Sensors mounted in a reflect mode

Siemens employs Transit Time principle for its Clamp-on Ultrasonic Flow meter SITRANS FS230

SITRANS FSS 200 clamp-on ultrasonic sensor pair A & B simultaneously transmits and receives acoustic signals directly through the pipe walls, where the refraction angle θ through the fluid is governed by Snell's law of refraction.

Sinθ = C / Vϕ (C= speed of sound in fluid and Vϕ is phase velocity in pipe wall which is a constant).

The average transit time T_{fluid} of soundwaves in fluid between the sensors A and B is calculated by the advanced transmitter SITRANS FST030 by subtracting the computed fixed times within the transducers and pipe walls. The meter automatically compensates for the changes in sound velocity in fluid based on the variations in measured average transit time between sensors A and B.

The time of travel of the soundwaves from sensor A to B ($T_{A,B}$) in the direction of the flow is shorter than the soundwaves that travel from sensor B to A ($T_{B,A}$) against the flow. The time difference, ΔT, is used to compute the integrated velocity(V) of the fluid as shown in the equation below. Vϕ is the velocity of soundwaves that travels in the pipe wall and is constant, also known as phase velocity.

$$V = (V\phi/2) \times (\Delta T/T_{fluid})$$

Once the fluid velocity (V) is determined, the fluid Reynolds number is computed to apply a correction factor (K_{Re}) for fully developed profile. This requires programing the inside pipe diameter (Di), fluid dynamic viscosity (μ) and density (ϱ) in the transmitter SITRANS FST030. The volumetric flow rate (Q) is then calculated by the equation:

$$Q = (K_{Re}) \times (\pi/4) \times (Di)2 \times V$$

Wide beam or Lamb wave transit time sensors:

Siemens is a pioneer in lamb wave (Wide-Beam) sensor technology. The Wide-Beam sensors are selected based on pipe wall thickness, and they transmit a wide range of frequencies through the pipe and locates a frequency that matches close to the pipe wall. This frequency is transmitted through the fluid with the pipe acting as a wave guide. This provides a wide area of beam to optimize the signal to noise ratio and improves the measuring accuracy to +/-0.5% to +/-1% of reading. It also tolerates aeration and solid particles in the fluid much better.

Lamb wave or Wide-Beam sensors uses lower energy and are designed for steel pipes but can also be used with Aluminum and Titanium pipes. The signals are more cohesive, prominent, and precise. As a result, we can mark the arrival of the receive signal with greater accuracy. By contrast, a one size fits all approach as does our competitors, it becomes necessary to "crank-up" the transmit amplitude to blast the signal through the pipe and as a result the signal suffers by arriving less pronounced and less precise.

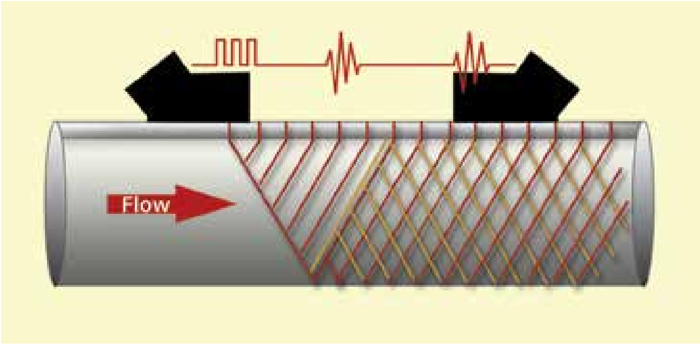

Figure 2: Lamb wave wide beam sensor where pipe is used as a wave guide

For improved flow profile average and to get the highest accuracy, the sensors can be installed with 1, 2, 3 and 4 path on a single pipe in reflect mode or in direct mode shown below in figure 3.

Higher performance with Digital SITRANS FS230

Instant digitalization of the signal, improved signal to noise ratio and reduced susceptibility to noise enhances SITRANS FS230 accuracy up to +/- 0.5% to +/-1% and repeatability of

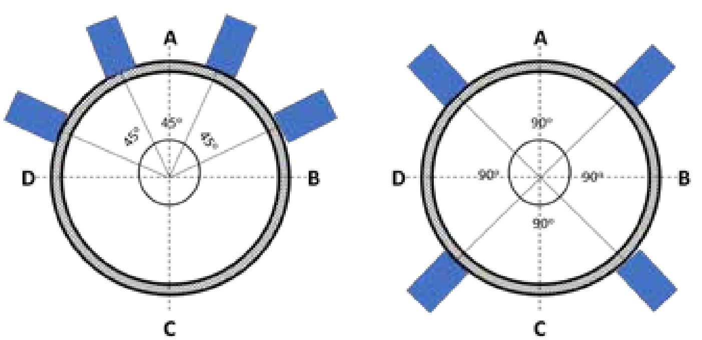

Figure 3: Four path installation in reflect mode (Left) and direct mode (right)

+/-0.25% (ISO 11631) of reading. It brings the advantage of a wider turn down ratio. The fast update rate of 100 Hz from sensor interface to the transmitter and control system enables FS230 to detect and update any flow changes within 10 mS.

The DSL electronics module receives the analogue signals from the sensors which are digitized and sent to the transmitter. A SITRANS FS230 flow system comes with two options: an integrated DSL for ordinary area installations, or the external variant in an explosion-proof housing.

SITRANS FS230 with a digital platform, accurately measures volumetric flow in standard applications, but also in complex applications; it can accept pressure and temperature sensor inputs to provide accurate mass flow and volumetric flow at standard (or normal) conditions. The process values, along with extensive diagnostics parameters are available on local HMI. They are then communicated to a control system via HART or Modbus, for the operator to verify whether the flow meter is accurate and healthy.

Figure 4: The Siemens SITRANS FS230 Flowmeter System: FSS200 sensors and FST030 Transmitter

SITRANS FS230 in gas flow measurement applications

Typical applications are the verification of the permanently installed flow meters, the measuring of high-pressure gas networks, gas power plant compressors, gas inventory balancing, gas production in chemical industry and temporary billing. The pipe sizes it can cater are DN50 to DN1500 sizes with minimum pressure of 8 bars in steel pipes and velocity of gas up to 40 meters/sec.

The SITRANS FS230 flow system for gas measurement consists of two/four pairs of SITRANS FSS200 wide beam clamp-on sensors, internal or external digital sensor link and a SITRANS FST030 transmitter as in figure 5.

Temperature changes are measured via external sensor or analogue input and pressure changes via analogue inputs to FST030 are necessary for mass flow and standard volume flow corrections.

Sending ultrasonic signals through a gas is a challenge. At low pressure conditions, the signals are being scattered a lot more, causing a lower signal-to-noise ratio. Using Lamb wave Sensors with Wide Beam Technology can remedy this. Flow speeds of up to 40 m/s and more can cause beam blowing but the angle of incidence is much smaller than in liquid applications and thus the sensor distance is also smaller which mitigates the effect of high flow speeds on the sonic signals.

SITRANS FST030 transmitter has an internal AGA 8 gas table, which was created with the current gas chemical composition, taking pressure and temperature into account. Based on the actual measured values of the current flow rate, the FS230 accesses the AGA 8 gas table and determines the current viscosity, calculates the Reynolds number, and corrects the volume flow accordingly and able to output the current volume or to carry out the mass or a standard volume calculation.

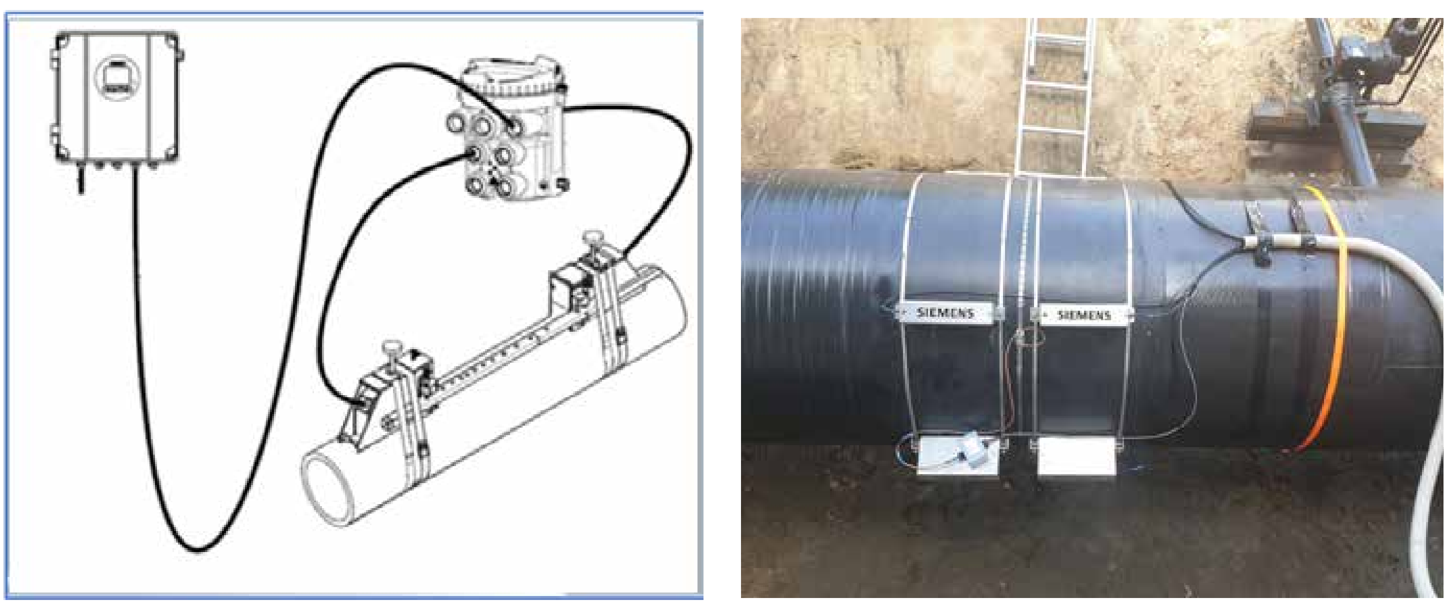

Figure 5: Clamp-on flow meter SITRANS FS230 system components and natural gas flow measurement application with "Soundcoat" to enable operations at low amplitude signals found in gas measurement

Test of impact of Hydrogen Content up to 30% in Natural Gas on SITRANS FS230 Clamp-on Flowmeter:

DNV-GL in Groningen, Netherlands have performed the test on their multi-phase loop test bench using 5 different gas mixtures (Pure Nitrogen, Natural Gas or G gas, Ggas+10% Hydrogen, Ggas+20% Hydrogen, Ggas+30% Hydrogen) at two different pressure conditions 16 bar and 32 bar.

Figure 6: DNV multi-phase loop test bench

Test System: SITRANS FS230 (GAS) on a 6" Steel Pipe

Test

- Flow rate: Qmin: 16 m^3/h, Qmax 900m^3h (flow velocity: 0.2 m/s - 15 m/s)
- 20 test runs of three repetitions at the test points for 100 seconds each
- Sensors were mounted on DNV's own pipeline without any calibration before the test!!
- The test measurements for natural gas showed a typical measurement error of ~1.3% which is taken as a reference value for subsequent measurements

Figure 7: Wide-Beam Sensors FSS200 in 2-path reflect mount, FS230 transmitter and External DSL

Results: SITRANS FS230 Repeatability and average meter errors and its drift behavior

	Gas type	Average error	Average repeatability (%)	FWME Flow weighted mean average error	FWM flow weighted mean repeatability
1	N2 p=32bara	1.41%	0.051	1.62%	0.055
2	N2 p=16bara	1.13%	0.080	1.37%	0.114
3	Ggas p=32bara	1.20%	0.062	1.22%	0.071
4	Ggas p=16bara	1.39%	0.044	1.40%	0.047
5	10H2 p=32bara	0.76%	0.105	0.84%	0.098
6	10H2 p=16bara	1.08%	0.062	1.21%	0.066
7	20H2 p=32bara	1.02%	0.059	1.06%	0.062
8	20H2 p=16bara	1.38%	0.061	1.40%	0.067
9	30H2 p=32bara	1.01%	0.057	1.01%	0.061
10	30H2 p=16bara	1.27%	0.114	1.20%	0.079

Figure 8: Summarized Calibration Results for Test on SITRANS FS230 Gas Flow Measurement system

Local manufacturing and Digitalization

Siemens in Peterborough is a local Canadian manufacturing hub of Siemens process instruments including Clamp-on flow meters and delivers quality instruments with the shortest lead time possible.

The clamp-on flow meter SITRANS FS230 are easily integrated into the cloud-based Siemens Mindsphere Platform for leak detection and similar remote applications using Siemens Apps. Siemens Process Instrumentation products are distributed in Quebec and Ontario exclusively by Franklin Empire.

Links for more information:

1) www.siemens.com/fs230 for technical information case studies and PIA life cycle portal
2) https://franklinempire.com/en/flow-measurement to book a meeting with a Franklin Empire Process Instrumentation Specialist
3) Contacts at Franklin Empire
   Quebec: stephan.laperriere@franklinempire.com
   Ontario: todd.rogers@franklinempire.com
   1-800-361-5044

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SIEMENS FRANKLIN EMPIRE

GAS MOISTURE ANALYZERS: WITH J22, THE NEXT GENERATION IS ARRIVING

Oil and water don't mix, but methane and H20 certainly do, which challenges producers to remove the greatest amount possible of the latter to deliver an acceptable commercial product, and maintain safety of their operations.

With the long distances natural gas often travels on its multi-stage journey from wellhead to local distribution networks, moisture measurement is performed multiple times en route : at production and gathering sites, along upstream pipelines, at custody transfer points, compressor stations, storage facilities and in the distribution markets. Given the commercial implications of making natural gas (or biogas) as 'dry' as possible, expectations for natural gas measuring instruments are constantly increasing. Operators want the highest levels of process and product quality, coupled with lowest possible maintenance and total cost of ownership.

Meeting such elevated expectations is keeping pressure on vendors for a new generation of TDLAS gas moisture analyzers, which Endress+Hauser is ushering in with the new J22 series. The J22 is the first in a series of advanced gas analyzers, powered by SpectraSensors technology, to be launched into the market.

While most moisture is removed during initial processing of the raw gas, some can be added back during downstream transmission via condensation along pipeline networks, and that is both a commercial and safety issue. Moisture measurement along trunk lines provides early detection of potentially hazardous hydrate buildup, leaks caused by corrosion or moisture buildup that could lead to a shut-in at a custody transfer point. A wetter product has a lower BTU value; Distribution companies have their acceptable delivery standards. For example, Enbridge says the water vapour content of gas in its system is typically 16-32 mg/m3.

Natural gas streams may also contain high levels of solid and liquid contaminants as well as corrosive gases in varying concentrations (glycol, methanol, compressor oil, sulfur compounds). This presents a challenge for some older moisture measurement technologies. The contaminants destroy some moisture sensors and cross-interference effects with the moisture readings must be avoided. With custody transfer in particular, false positives for any reason are very costly because the gas cannot be delivered if "wet".

The traditional approach to moisture measurements uses a chilled mirror. A chilled mirror determines dew point on a carefully cooled mirror, it's a slow and subjective measurement because many other components in gas streams can condense on the mirror. Additionally, a variety of electronic sensors have been used which rely on the adsorption of water onto a sensitive surface placed into the gas stream. In practice, sensors that are in contact with natural gas are adversely affected by gas components, causing errors, interference, and costly failures. Their readings are often unreliable.

TDLAS, or tunable diode laser absorption spectroscopy, is a gas measurement technology introduced to the natural gas industry by SpectraSensors over 20 years ago. It was a game changer then and still is unrivalled for accurate and consistent measurement. Since its inception, TDLAS has demonstrated its reliability in thousands of installations worldwide. TDLAS doesn't require consumables or have contact with contaminants. There are no wet up or dry down hassles. The laser never comes in contact with the gas so it won't become corroded like other sensors. TDLAS units suffer no impairment from glycol, methanol, amine, H2S, or moisture slugs in the gas stream. The rugged nature of TDLAS analyzers allows them to be used along pipelines. They require very little maintenance, and are immune to interference that plagues other methods. Their low-maintenance characteristic can be a huge time- and cost-saver for operators.

Endress+Hauser's TDLAS analyzers require no calibration in the field; the calibration is stable for the life of the analyzer, yet validation of H2O concentration is simple to perform. The analyzers are equipped with validation gas connections to accept binary gas blends containing H2O.

Endress+Hauser's TDLAS portfolio includes analyzers that can detect and measure more than one contaminant (two or three of H20, H2S, C02 or O2), however, moisture content is monitored more frequently along the supply chain.

The new J22's advanced diagnostics and superior measurement algorithms differentiate it from all TDLAS analyzers that have proceeded it, assuring the highest analyzer availability yet. Its highly developed algorithms, plus the sophisticated diagnostics, monitoring, and verification concept of Endress+Hauser Heartbeat Technology, assure operators of fewer failures, lower operating costs and improved reliability, which translates into a sustainable competitive advantage.

Download the J22 brochure **CLICK HERE**

The heart of the TDLAS measurement lies in the gas sample cell where the laser and signal detector are isolated from process contaminants, eliminating measurement errors. J22 analyzers have an accuracy of ±2 ppmv plus 2% of readings and a repeatability of ±1 ppmv or ±1% of reading (whichever is greater) and measuring ranges up to 0-6000 ppm (0-284 lb/mmscf) H2O

State-of-the-art gas mixing technology is used during factory calibration of J22s for measurement confirmation. This ensures superior measurement performance throughout the analyzer's operations in the field.

The J22 analyzer platform offers versatile operating options using a standardized Endress+Hauser concept. It is tailored to meet gas quality specifications, prevent pipeline corrosion, stop hydrate formation, and minimize the risk of explosion to ensure human safety and asset integrity. The J22 uses proven virtually interference-proof metrology (with NIST traceable calibrations) to avoid shut-in, flaring, and interrupted gas delivery incidents.

The J22 can be integrated seamlessly into any plant asset management system, providing reliable information for optimizing gas or biogas production measurement processes.

J22 systems are available in multiple mounting configurations suitable for various locations:

- Panel mounted sample conditioning system for installation in shelters or in temperate locations
- Heated enclosure for use in outdoor settings or locations with harsh environmental conditions
- Filtration, with or without bypass to remove particulates or liquids in gas stream, assuring uninterrupted measurement
- Pressure regulation with or without pressure relief valve to ensure a steady gas flow into the analyzer for consistent and continuous measurement
- Rugged brackets for wall, rack, or pipe mount for effortless installation

The J22's sampling system is built onto a compact panel with an option bypass, pressure relief and safety purge and can be packaged in a stainless steel enclosure for extra weather protection. This heated enclosure ensures reliable operations in even the harshest winter conditions. The J22 has all Class 1, Division 1 and Zone 1 certifications for locating in hazardous areas.

Many compressor stations the supply chain are fully automated. So operators want gas analyzers that need minimal maintenance or inspection.

The J22 TDLAS analyzer's easy-to-replace components minimize downtime for the most efficient continuous analysis. Components are easily accessible and field-serviceable, allowing for quick replacements or upgrades. All replacement parts are accessible using simple hand tools. The simple-to-remove gas sample cells are designed to allow convenient cleaning and servicing.

The J22 functions equally well as a biogas/biomethane moisture analyzer, and it's future proof. Endress+Hauser invested early in hydrogen blending stations to simulate customer streams for research and development, production calibration, and testing in hydrogen. The J22 is one of the first analyzers to benefit from this investment. It has a built-in capability for hydrogen-containing natural gas streams. Adapting the instrument for a hydrogen-containing stream is a simple field adjustment to the H2 concentration found in the user menu.

For more information on the J22, download **THIS BROCHURE** or **VIEW THIS VIDEO**


We understand how you need
to reduce complexities at your plant.
CLEAN PROCESS
+ CLEAR PROGRESS
You strengthen your plant's safety, productivity
and availability with innovations and resources.