Gas Measurement Challenges

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Picture this: The whole family and the neighbours are over for a great barbeque in YOUR backyard. You fire up the propane barbeque grill and 5 minutes later - what?? No gas?? Due to the lack of a proper gauge or instrumentation it is impossible to know how much gas is available. What do you do now? While this is not as dramatic it certainly resonates with the following article on how important proper measurement and instrumentation applies to your operation.
I know of a company that learned they were using the wrong meter tube diameter at a custody transfer location for more than ten years. So we discussed how this issue affected the measurement at that location and began determining how to rectify and resolve the problem. Does your company have a similar problem in the field? How would you know how to determine if you do or don't?

The frequency with which gas measurement is reported has changed in the industry over time. In the 1970's and before, the data was recorded on paper charts and then integrated to determine the volume measured over usually a seven day period. The integration accuracy was dependent on the person performing the integration and the type of chart being integrated. With the advent of electronic flow computers the data was collected manually and transferred weekly or monthly initially. Once nominations came into existence, the frequency with which the data was collected increased. Many companies started utilising valve control capability, available as an add-on with the flow computer, so that the volume delivered was within the five percent tolerance allowed without penalties. Today, many companies are collecting data remotely on an hourly basis so that they can better manage their systems. With software available to highlight data which requires additional investigation, many of the field issues are resolved more quickly with these tools. However, a significant number of issues will require the measurement technician to check the installation for incorrect information entered into the flow computer or subtle errors in data which can cause major issues. Are your technicians up-to-date with all the new industry standards and knowledgeable on making sure your company is maximising every dollar possible? There are many hidden issues that make a difference, including an incorrect calibration of the transmitter because of incorrect technique or a misunderstanding of the requirements for proper calibration. These issues are almost impossible to find unless a measurement audit is performed to locate this type of problem. For example, I witnessed a calibration of a differential pressure transducer as part of a measurement audit. The technician performing the calibration had liquid condensing overhead of his deadweight tester that landed on the weight stack during the calibration. He had no idea that the liquid on the weight stack would impact the calibration. There is absolutely no way to find this type of mistake without a knowledgeable person witnessing the technicians work. How many times has a similar issue impacted the measurement results for your company? How many dollars have been affected? Do you know if this might be happening in YOUR Company?

A bit of history

The flow computers initially calculated the volume utilising the input from the temperature, static and differential transducers/transmitters on an hourly basis. With improvements in capabilities of the flow computers today many of them are now performing a full API 14.3 Part 1 and AGA 8 calculation every second. (* see footnote) Data from sample analysis can be uploaded from a portable gas chromatograph if utilised or uploaded from the lab into the flow computer, so that a full detail calculation is possible instead of the lessor AGA gross 1 or 2. Many companies install on-line gas chromatographs for ultrasonic meters so that a live speed of sound is available for proper measurement. If linear meters such as gas turbine meters are used the flow computers receive pulse data. The flow computers are capable of either linear or square root calculations utilising all of the data from the instrumentation and the composition uploads making all the data readily available on an hourly basis.

There are many advantages of collecting the data in timely manner. Check out what these advantages are at: www.ongt.net/collecting-data.html

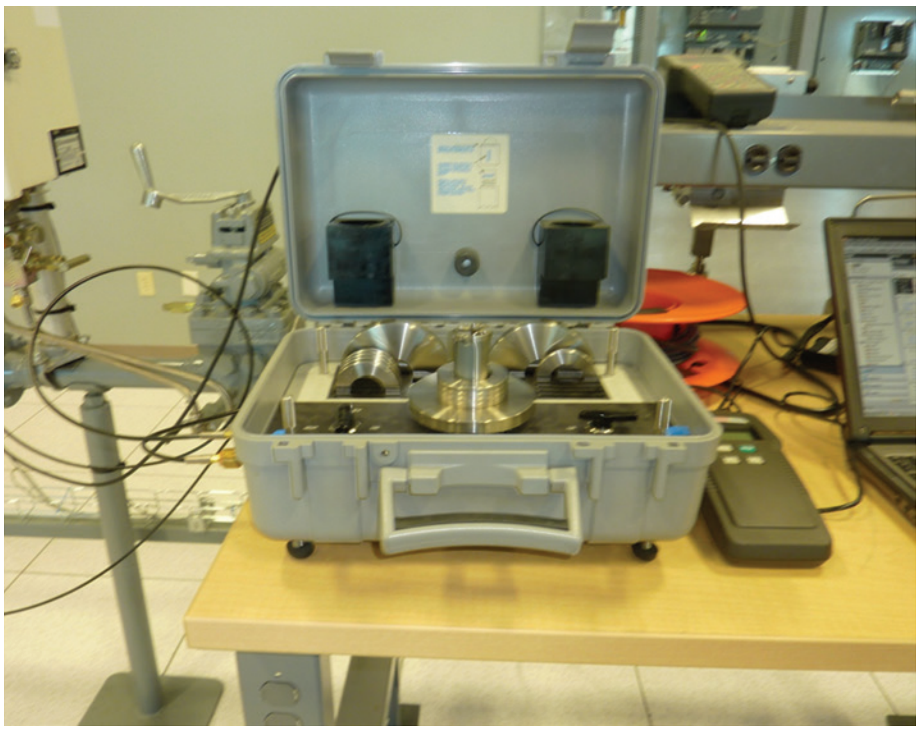
Also watch for next months article on capacity allocation and nominations to supply natural gas to the marketplace. Also, you can get a sneak peak at this on our website at www.ongt.net/

Instrumentation installations

In order for the data collected to be accurate, the transmitters must be properly selected for the application and installed properly, which includes proper grounding. If the transmitter is to be used in an application where the concentration of H_2S or CO_2 is high then a more hardened transmitter should be selected. Typically this will result in a more expensive and less accurate device. Other installation considerations to be taken into consideration include the custody transfer metering near high voltage power lines, the use of cathodic protection, the presence of pulsation, and water hammer effects which can deform or rupture the internal diaphragm of the transducer/transmitter. The technician needs to realise grounding a transmitter that is on a cathodically protected meter tube only serves to short the cathodic protection through the transmitter body. Other issues include radio frequency interference and electromagnetic interference. Depending on the type of wiring used with the temperature transmitter, coiling of the tuned wire can cause a change in the signal being received because of electromagnetic interference at least on some of the older temperature

Temperature verification out in the field

Temperature verification



Weight stack for the differential

Weights on the device with with computer readings

transducers and flow computers. Could any of your instrumentation be affected with any of the above issues?

Data validation and verification

Most companies today utilise software which is either developed in-house or is commercially available to handle the data collection and data validation. The data validation process identifies measurement data that falls outside of the acceptable user defined variance allowed. Thus the system highlights any data that looks suspicious. This minimises the work required in the office to verify that the data is correct. It also allows an analyst to contact the measurement technician to request that the data be verified if there is any question. This might require catching another gas sample for analysis, checking the orifice plate bore, the differential pressure transducer, static pressure transducer, or the temperature transducer, etc. The measurement technicians need to be especially cautious with the static pressure transducer and understand if the transducer/transmitter is a gauge or absolute device. Not understanding the equipment has caused many a problem in the past. The software also is capable of identifying missing data, constant outputs that should be live and other similar checks which indicate there is a problem.

One of the other important capabilities of the software is to manage the scheduling of meter verification/calibration. This assists the measurement technician by sending them a monthly schedule of the meters requiring inspection so that they stay on top of the meters requiring inspection and verification.

Ideally the calibration instrumentation the measurement technician utilises should not only be in good working condition but also three times the accuracy of the instrument being calibrated. Since this can be difficult to achieve, the industry allows calibration devices to be twice as accurate as the field device being verified/calibrated. The calibration devices should have an accuracy of at least 0.1 per cent of reading for static and differential pressure and at least 0.5 degrees Fahrenheit for temperature. The calibration devices need to be certified on a yearly basis. Dead weight testers and manometers are only one step away from the National Institute of Standards and Technology or NIST for short, so they are considered primary pressure standards. Precision gauges, sensors and transducers are considered to be secondary comparison standards. Electronic pressure testers are being used in the industry more today because they are cheaper and more portable, but the user needs to recognise they will add uncertainty to the verification/calibration.

The American Petroleum Institute (API) in the Manual of Petroleum Measurement Standards in Chapter 21.1 Flow Measurement Using Electronic Metering Systems – Electronic Gas Measurement published in February of 2013 covering all aspects of flow computers including the verification/calibration procedures in section 8.2.2. The document warns users that ambient temperature can have an effect if the temperatures are extreme. The standard also states that the ambient temperature should be recorded as part of the verification/calibration process. The standard also recommends that if the measurement is being performed high static pressures the differential zero should be checked at atmospheric and line pressure conditions.

The document also warns that if a differential pressure device is installed in a service with high static pressure conditions, the line pressure can cause a shift in the calibration. It is recommended that the differential pressure zero be checked at both atmospheric pressure zero and line pressure zero. The manufacturer should provide guidance on line pressure effects and compensation techniques.

Additionally there may be atmospheric pressure effects as well. When gauge pressure transmitters are used they need to be compensated for atmospheric pressure which varies with both elevation and current weather conditions. The API 21.1 standard in section 8.3.3 provides the user with an equation to determine the elevation correction. Errors due to the atmospheric pressure effect are more significant in low operating pressure installations. Absolute pressure transmitters or sealed gauge transmitters are capable of reducing the static pressure uncertainty by accounting for the atmospheric pressure changes.

Since the atmospheric pressure can change by as much as 0.5 psi from the average atmospheric pressure conditions, the atmospheric pressure should either be measured or the variability included in the calculation of the verification tolerances. Consequently, some companies utilise a barometer which reads the actual atmospheric pressure conditions taking into account both elevation and current weather conditions to minimise the atmospheric pressure impact.

The process of verification/calibration is to isolate the meter transducer/transmitter from the process flow and apply a known standard using the calibration device, either a deadweight tester or electronic pressure tester and compare the resulting readouts. As long as the results are within the allowed tolerance only verification is required. If the results exceed the tolerance allowed a calibration of the instrument is required. The verification/calibration is recorded either electronically or on a paper test report for documentation.

As transmitter accuracies have improved it is more difficult to field calibrate as it is difficult to find instrumentation that is twice as accurate. A couple of different approaches have been taken. One approach is to use factory calibrated transmitters and only verifying the device meets the verification tolerances. Another approach is to utilise redundant transmitters and as long as they compare closely making the assumption they are operating properly. If the transmitter does not pass the verification test then the transmitter should be zeroed and retested. If it does not pass the verification test at this point it should be repaired or replaced.

Another important point to make is if the verification/calibration equipment has a specification different from the span/operating range of the device being calibrated, the verification/calibration device needs to be converted to the device range accuracy specification to determine if the system meets the required accuracy requirements. Section 8.4 of the API 21.1 document provides examples of determining if the calibration equipment meets the required specifications over the device operating range.

By having properly calibrated instrumentation as part of the flow computer and frequent data validation by the accounting software, it is possible today to minimise the penalties from either over or under delivering nominated volumes. It is also possible to minimise errors from incorrect data as the data validation capabilities of the software highlight these potential issues. In order for the gas measurement system to function efficiently, both the measurement technicians and the analysts must have a good understanding of the processes and the requirements involved in obtaining accurate and timely data.

Today's financially challenging operating conditions are a fact of life in the oil and gas industry. These challenges reinforce the need for accurate measurements in general. There have been industry field situations wherein modest under-reporting errors have existed for long time periods, before being noticed and corrected.

In a small flow rate scenario, this has resulted in a noticeable missed opportunity for revenue at that measurement location over the time period the measurement was incorrect.

In a high flow rate situation, this missed opportunity can result in very significant dollars of lost revenues for a company. Improving measurement accuracy has been known to increase profits at a location sometimes with minimal training and / or equipment expenses involved.

Companies utilising frequent monitoring of the measurement data with a software program that validates the data and will indicate areas of concern will help decrease but not necessarily eliminate measurement or calibration errors.

Knowledge can be modestly expense and very valuable. A lack of knowledge in the measurement arena can be very costly.

Hence, there exists an opportunity for ongoing industry training, that includes knowledge while being based upon significant industry experience. Training that includes Team training so that issues can be identified and resolved. It is beneficial to train both the measurement technicians and the analysts in an area at the same time. That way they can both learn the necessary items for accurate measurement and data analysis and reporting. Knowing the person on the other end of the phone when the analyst calls and asks questions or requests additional work makes communication more effective. In real life, this can be much more cost effective than ongoing issues that remain unknown and unresolved.

Fire up the Barbie… Hot dogs anyone?

Jane Williams is President of ONGT, (Oil & Gas Training Corporation) which specialises in measurement training.

Jane Williams has over 40 years of experience in the oil and gas industry and has been very involved in the development of industry standards. She has a master's degree in engineering and has a tremendous amount of field experience. Jane's vast knowledge allows her to explain difficult concepts in an easy to understand manner.