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Paper 4.2

Flow Measurement Field Calibrations by Radioisotope Tracers in Offshore, Oil and Gas Industry

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1 INTRODUCTION

Indmeas is a measurement service company specialized in flow measurement field calibrations. The calibrations cover both liquid and gas flow measurements. The field calibrations of Indmeas have been accredited since 1994. The accredited flow range is 0.5 – 5000 l/s for liquid and 5 – 5000 000 l/s for gas flows. The specified flow ranges indicate that the main interest lies in large flows. Since 2004 the best accredited calibration uncertainty has been 0.5 % for both liquid and gas flows.

Since the company started in 1986 Indmeas has carried out about ten thousand field calibrations for the process and energy industry of Finland and Sweden. This figure is large even in global terms and except for Indmeas there seems to be no other significant actors in this market. So far only a few hundred calibrations conducted by Indmeas have concerned oil or natural gas flow measurements but the number is expected to rise rapidly. Indmeas has presented its field calibration method earlier in [1] and [2].

2 REQUIREMENTS FOR MEASUREMENT ACCURACY

It is the authorities that have been the driving force in issuing requirements for flow metering accuracy and emphasizing the importance of measurement quality assurance. Examples of this are among others:

- Emission permits with limits for allowed emissions into water and air
- Regulations concerning the measurement uncertainty in fiscal measurements in the North Sea area
- A trade system for NOx emissions in Sweden
- A CO2 emission trade system
- Gas market liberation
- Emission trade for produced water in the British North Sea area

More requirements for measurement quality assurance are expected during the coming years at an exponentially increasing rate. Significant issues ahead are likely to include the enlargement of the CO2 - emission trade to other emission gases and requirements concerning energy efficiency.

The requirements emphasize the measurement accuracy on site and hence the quality assurance measures on site are preferred [3].

The results of the work of the authorities has had a significant educational impact on the process industry. It is obvious that the measurement quality assurance methodology learned will in the next stage largely be adopted in the internal measurements of the process industry.

3 MEASUREMENT QUALITY AT THE END USER LEVEL

The traditional chain for the assurance of flow measurement accuracy of the end user consists of two basic components:

- the calibration of the meter in ideal laboratory measurement conditions
- reproduction of the laboratory measurement conditions on site

The effect of the inevitable differences between laboratory conditions and those on site is estimated by using experimental laboratory data or by disregarding it, the latter being the dominant method.

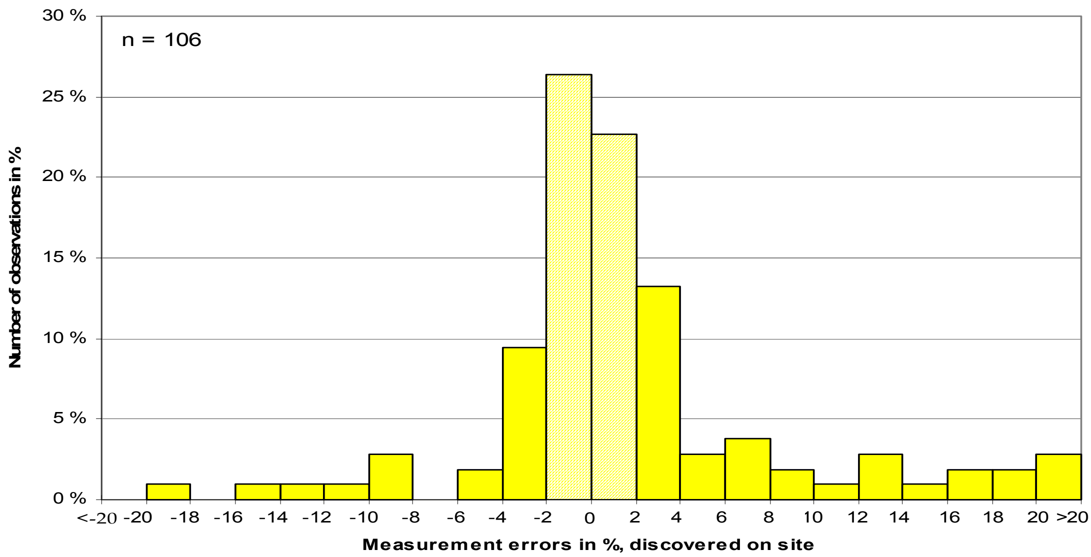

Fig. 1. Total measurement errors in natural gas flow measurements observed in first time field calibrations. Number of observations 106.

The measurement positions of Fig.1 are the industry`s own measuring positions representing gas delivery to boilers, process ovens, infrared heaters etc. The majority of the meters are turbine meters. Fig. 1 thus represents the measurement accuracy that the industry on average will reach when it buys a turbine meter and just installs it in the pipeline according to normal installation practices.

The measurement accuracy achieved is more than a decade worse than that specified by the meter manufacturer. This strongly suggests that the meter itself is the most accurate component in a flow measurement chain and that all significant errors originate from the rest of the measurement chain.

Fig. 2 shows the corresponding statistical information on oil measurements. Here the measurements are mainly fuel oil measurements from the energy industry and liquid hydrocarbon measurements in the oil refining process. Due to the smaller number of observations the distribution is more obscure. However, the figure clearly indicates that in this case too the measurement uncertainty originating from outside of the meter itself is entirely dominant.

Fig. 3 represents the total measurement uncertainty observed in the first time field calibrations for district heating water flow measurements. The reason for showing this figure is the starting emission trade for produced water. As a flow measurement application the measurement of district heating water and produced water might be comparable. The statistical measurement uncertainty in Fig. 3 is somewhat better than those of Figs. 1 and 2 being due partly to the fact that the measurement application is somewhat easier than the two earlier ones. However, the improvement in the statistical accuracy does not change the general conclusion on the origin of the dominant measurement uncertainty.

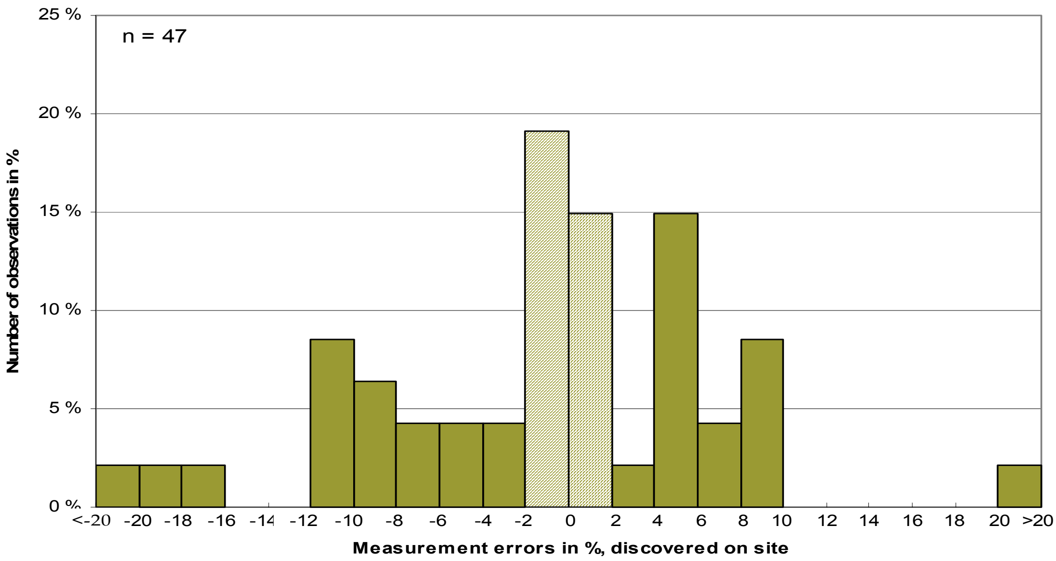

Fig. 2. Total measurement errors in oil flow measurements observed in first time field calibrations. Number of observations 47.

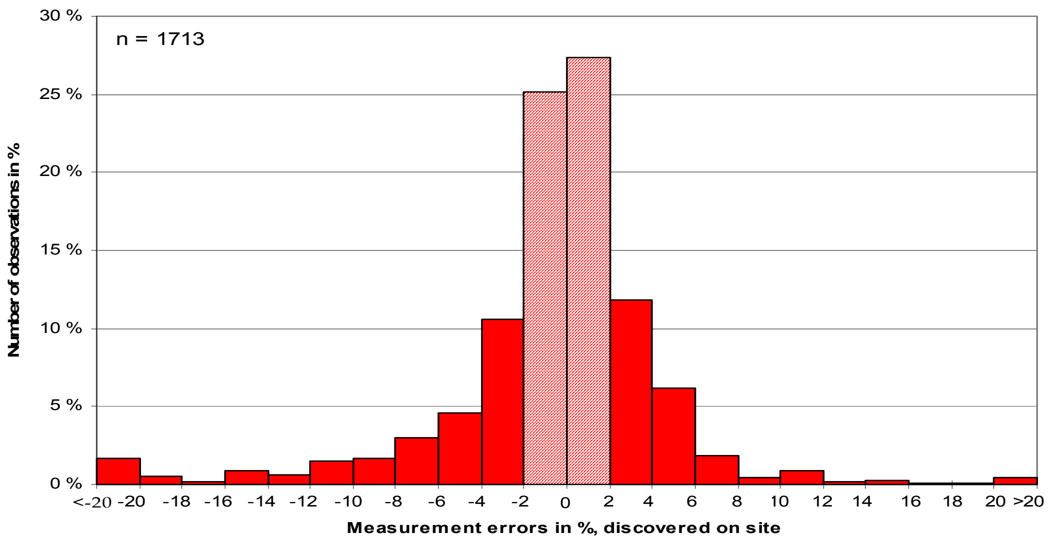

Fig. 3. Total measurement errors in district heating water flow measurements observed in first time field calibrations. Number of observations 1713.

Fig. 4 shows the corresponding statistics for stack gas flow measurement in the energy industry. The figure might be used to estimate the measurement uncertainty in flare measurements roughly. The gas velocity in stacks where the meter is installed is normally 10 – 30 m/s and ultra sound meters are commonly used. As a fluid to be measured stack gas is probably more difficult due to the higher temperature, particles present and corrosive circumstances. One would expect, however, that these differences would in the first place just cause more maintenance work and a shorter meter life in stacks. Fig. 4 suggests that the required measurement accuracy of about 5 % is probably not reached in the flare gas measurements of the platforms. The results from the first three field calibrations carried out by Indmeas so far for flare gas flow measurements at oil refineries support the assumption on the similarity between stack and flare gas flow measurements.

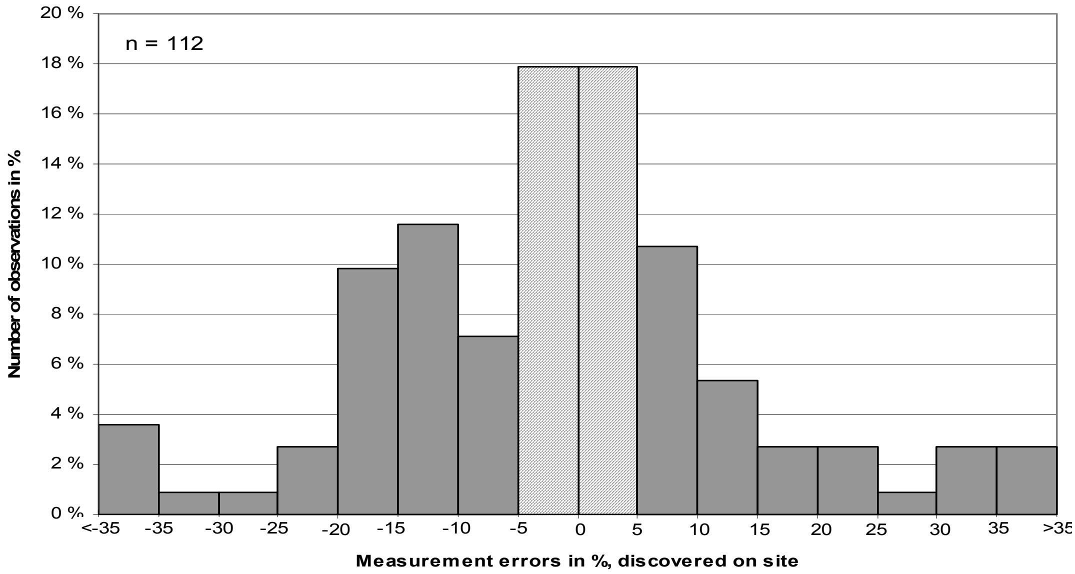

Fig. 4. Total measurement errors in stack gas flow measurements observed in first time field calibrations. Number of observations 112.

In certain specific measurement applications related to especially high economic values the measurement accuracy is undoubtedly much better than that represented in Figs 1 – 4. Fiscal measurements such as the shipping measurements of raw oil and oil products are often regularly field calibrated by using tank level measurements or piston provers. Correspondingly the installation positions of natural gas flow meters at pressure reduction stations are well standardised, a fact which certainly eliminates the majority of the uncertainty components otherwise present on site.

Guarantee measurements at power plants are used to assess whether the delivered boiler, generator or the whole plant fulfils the purchase conditions. The measurement procedure is based on the traditional accuracy assurance chain and is described in detail in standards which are followed as far as it is in practice possible to do so. Measurements are most often carried out by an independent measurement consultant. The most critical flows are the feed water, high pressure steam, condensate and the possible district heating water flow. The consultant typically reports his measurement results for these flows with an uncertainty level of 0.5 - 2 %. The comparison results obtained so far by Indmeas in several cases suggest that the actual measurement uncertainty of the consultant is in general hardly better than 6 - 8 %.

The conclusion is that the traditional chain for the assurance of flow measurement accuracy has proved to be fairly ineffective. In order to reach an adequate flow measurement accuracy at the end user level more effective measures are needed. It is obvious that the field calibrations constitute the basic tool in this work.

4 FIELD CALIBRATION METHODS

Piston provers provide the most accurate and expensive field calibration method for liquid flows. The calibration uncertainty is of the order of 0.2 %. On off-shore platforms their constant use is obligatory, a fact which obviously keeps them fully operational.

A comparison with tank level measurements is a commonly used method to verify shipping measurements. Refiners using this method estimate that the uncertainty reached lies close to 0.5 %.

The weighing of liquids using a tank truck and truck scale is one way for industry to carry out field calibrations of liquid flow measurements. This method is not very attractive because of the hazards associated with the handling of hydrocarbon liquids.

As an indication of growing interest in field calibrations two laboratories, the Danish Technical Institute and Inspecta Oy Finland, were accredited in 2005 for field calibration of water flow measurements. The former uses the LDV-method with the best measurement uncertainty of 1.0 %. The method used by the latter involves an ultra sound clamp on master meter with the best uncertainty of 1.6 %.

Today the tracer methods seem to provide the most effective and flexible field calibration method for industry. In particular the transit time method based on the use of radiotracer is especially well suited for the severe measurement conditions in the process industry. It suits both liquid and gas flows, has a very large flow region and reaches a fairly small uncertainty already in moderate measurement conditions. The method still possesses a remarkable development potential.

5 THE RADIOTRACER TRANSIT TIME METHOD

The principle of the radiotracer transit time method is presented in Fig.5.

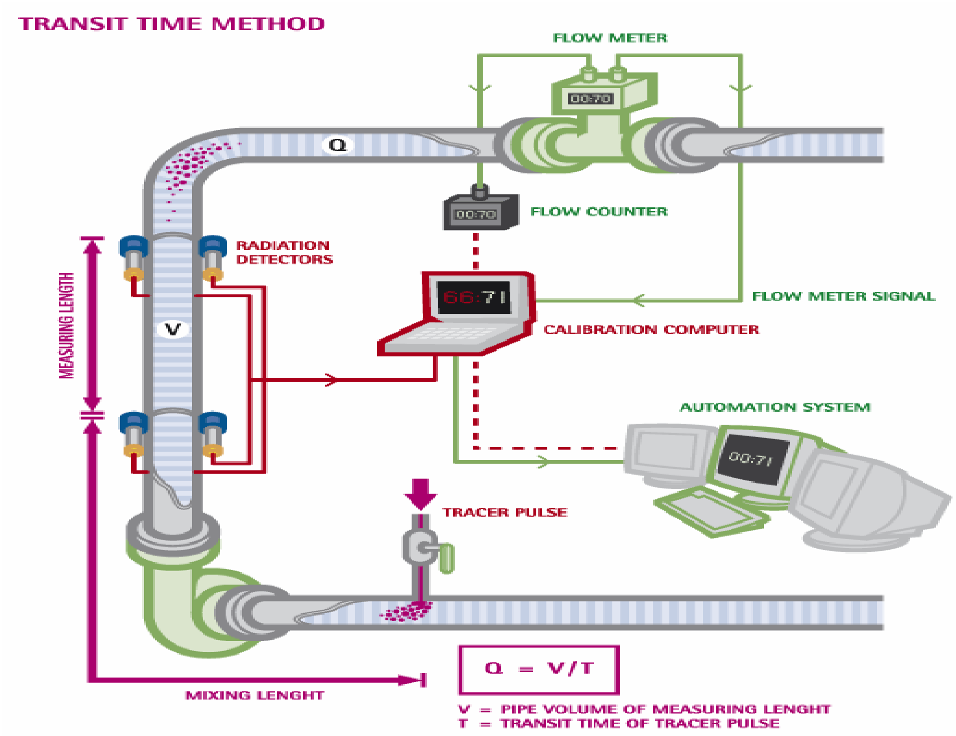

Fig. 5. The principle of the radiotracer transit time method

A small amount of radioactive liquid or gas tracer, depending on the fluid in question, is injected momentarily into the flow. Downstream where the tracer pulse has mixed over the flow cross section its velocity is measured on a straight pipe section by using two radiation detectors mounted on the pipe. The gamma radiation emitted by the tracer penetrates the pipe wall and is detected by the detector. When the tracer pulse passes the first detector the tracer concentration response is registered. A similar measurement result is registered when the pulse passes the second one. The flow reference value Q_{ref} is obtained from the following simple formula:

$$Q_{ref} = \frac{V}{T} = \frac{\pi * D_{in}^2 * L}{4 * T},$$

where

V is the inner volume of the pipe between the detectors
T is the time the tracer pulse spends between the detectors
D_{in} is the inner diameter of the pipe
L is the distance between the detectors

T is determined as the time difference between the two measured responses. L is measured by using a calibrated measuring band. D_{in} is determined normally by measuring the outer pipe circumference by the measuring band and the wall thickness by an ultra sound thickness meter.

Q_{ref} is compared with the simultaneous average flow value of the meter under calibration. The tracer injection is repeated normally 7 – 15 times and the calibration result is obtained as the mean value of these repetitions. The transit time method is actually a modified version of the piston prover method where a rigid piston or ball is replaced by a more diffuse tracer concentration pulse and the accurate cylinder by a process pipe.

L is measured with a calibrated measuring band and its uncertainty can normally be disregarded. In pipelines with small diameter the uncertainty of D_{in} often dominates except in cases where a direct measurement of D_{in} is possible. With larger pipes, with, for example, a D_{in} of more than 100 - 150 mm, the uncertainty of D_{in} can be decreased in a straightforward way to a level of 0.1 – 0.3 % by simply making more measurements from the outside of the pipe. In order to reach a small stochastic uncertainty component the distance between the detectors must be sufficient in relation to the length of the tracer pulse. After the mixing over the flow cross section the length of the tracer pulse is typically of the order of some meters. The stochastic uncertainty component can only be estimated roughly beforehand because it also depends on the flow velocity and stability. In general, however, field calibrations aiming at a calibration uncertainty of 0.5 % demand a straight pipe section of the order 10 meters or more and a reasonably stable flow. Fortunately these requirements are generally fulfilled in positions where a small calibration uncertainty is desired.

The inner volume between the detector positions does not normally change with time. The repeatability of the method is thus roughly the same as the repeatability of the measurement of T. With long straight pipe sections available and with a stable flow the repeatability of the method easily reaches the level of 0.1 %. So the method can also be used for a very sensitive assurance of flow measurement stability.

6 CALIBRATION EXAMPLES FROM ON-SHORE

Example 1. A shipping measurement for liquid hydrocarbons

The relevant calibration characteristics:

The meter:	a turbine meter witha high frequency pulse signal available
L:	70 meters
D_{in}:	440 mm
Flow rate:	110 – 550 l/s

As normal the uncertainty of L could be disregarded. Due to somewhat varying dimensions between the pipeline pieces welded together several hours of measurement work was needed to reach a small uncertainty for D_{in}. By carrying out 12 measurements for the pipe circumference, 113 measurements for the pipe wall thickness and a few measurements for the paint layer thickness a total uncertainty of 0.07 % was obtained for the inner volume. The repeatability of the results from different tracer injections was very good so that even after 6 measurement repetitions a stochastic uncertainty component of 0.13 % was reached. The computational total calibration uncertainty was hence in this favourable case as good as 0.15 %.

Example 2. A fuel gas measurement at a refiner

Calibration characteristics:

The measurement:	Orifice measurement
L:	5.5 meters
D_{in}:	300 mm
Flow rate:	15000 – 19000 nm^3/h

The calibration uncertainty of 2.7 % remained in this case fairly large due to the short L, a relatively high flow velocity and rapid flow variations. The calibration, however, revealed a significant measurement error and in addition a logical error in the determination of the normalized flow.

Example 3. A flare gas measurement at a refinery

Calibration characteristics:

The meter:	ultra sound meter
L:	35 meters
Din:	740 mm
Flow velocity:	18 m/s

The calibration was carried out during production problems causing high and unstable flare flow. Despite altogether 25 measurement repetitions and a long L the total calibration uncertainty remained at 1.3 %. The uncertainty, however, was small compared with the significant measurement error revealed.

7 THE FIRST EXPERIENCE FROM AN OFF-SHORE PLATFORM

The only visit made by Indmeas so far to an off-shore platform had an ambitious goal: the field calibration of the flare flow estimator at high flaring. The task proved to be a fairly difficult one in terms of logistical and timing problems. Due to a last minute schedule change of the high flaring the first time two separate trips from Finland to the on-shore base were needed to get on the platform. In fact the high flaring was stopped almost immediately after it started because the temperature on the top of the platform began to rise dangerously. Only a couple of small tracer injections during the rapidly decreasing flare flow were carried out. Although the original goal of the visit was not achieved two essential development needs for field calibration work on platforms were identified.

The first development need concerned the tracer transport. For efficient calibration work the measurement group must be self supporting also with respect to the tracer and the equipment must be easily transportable by a helicopter. This has now been accomplished by switching to an easily portable radioisotope generator as the source of radioactivity for gas flow measurements.

The second development need identified concerned the methodology of flare flow measurement calibrations. The first trial proved that the timing of the calibration with a planned high flaring is in practice impossible. Hence flare gas flow measurement calibrations and estimator verifications must be carried out during normal platform operation time. In order to reduce economic losses due to increased flaring, the calibration data collection time needed on a flow level can now be suppressed to a few tens of seconds.

8 CONCLUSIONS

Field calibrations by the radiotracer transit time method constitute an efficient basis for flow measurement quality assurance in the process industry. It is a flexible, reasonably low cost method with a calibration uncertainty compatible with the requirements set by the rules of the CO2-emission trade and fiscal measurements. In the custody transfer measurements of oil refineries and natural gas networks this method is a new promising alternative to traditional quality systems based on tank level measurements and laboratory calibrations. The method has also been developed to meet the specific measurement circumstances prevailing on off-shore platforms as well.

9. REFERENCES

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