guidance document for application of the EU Commission's guidelines for monitoring and reporting of GHG emissions

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ABSTRACT

This document was prepared by a CONCAWE ad hoc group to address concerns from a number of member companies with regards to the level of uncertainty implied by the EU Commission's Guidelines for monitoring and reporting of GHG emissions.

It is intended for use by member companies and their national associations in order to assist them in their negotiations with national and local Authorities on this matter.

KEYWORDS

Greenhouse gas, guidelines, CO_2, refineries, uncertainty

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SUMMARY

In January 2004, the EU Commission adopted a set of guidelines for Member States and local authorities concerning monitoring and reporting of GHG emissions in installations covered by the emissions trading Directive.

There is particular concern in the Oil Industry with regard to the level of precision that is required by the Guidelines. This level is generally seen to be incompatible with general refinery practice and would be either unachievable or would lead to high extra costs.

This report clarifies some definitions and discusses, within the particular context of a refinery, various aspects of the Guidelines regarding methodology, inventorisation of emission sources, measurement practices and equipment, and emission factors.

In particular, the point is made that the global uncertainty on the emissions of a refinery may be significantly better than the uncertainty on a particular source, thereby opening the possibility to wave stringent requirements on certain sources without affecting the quality of the integrated data.

1. INTRODUCTION

In January 2004, the EU Commission adopted a set of guidelines for Member States and local authorities concerning monitoring and reporting of GHG emissions in installations covered by the emissions trading Directive [1] (further referred to as "the Guidelines"). This document was based on work by ECOFYS, a consultant appointed by the Commission in 2003.

Although the Oil Industry was able to comment on the original proposal, its recommendations were only partly taken on board. There is particular concern with regard to the level of precision that is required by the Guidelines. This level is generally seen to be incompatible with general refinery practice and would be either unachievable or would lead to high extra costs. In refineries, CO_2 emissions are indeed released by a relatively high number of sources. Quantification of both the quantities (activity data) and the carbon content (emission factor) of all sources rely on a number of measurement devices and laboratory analyses. All consequences of this specific situation were not fully recognised in the Guidelines.

In addition there are areas in the Guidelines that may lead to different interpretations by different authorities.

This document does not address all issues related to measurement and reporting of GHG emissions nor does it include a complete set of detailed calculation methodologies. Rather it focuses on certain specific aspects of the EU Commission's Guidelines particularly with regards to uncertainty. A wider overview of the issues at stake as well as detailed methodologies have been compiled in other Industry documents such as the IPIECA Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions [2] and the American Petroleum Institute Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry [3].

The purpose of this document is to provide CONCAWE member companies / refineries and their counterparts in the competent authorities of the Member States with a tool to arrive at realistic uncertainty expectations and for using the methodology that is most appropriate to their particular circumstances.

2. DEFINITIONS

Although the Guidelines are about uncertainty, precision and accuracy of measurement, these terms are not specifically defined. We suggest the following definitions that clearly separate random errors and systematic errors.

Precision:	The random variability of a measurement process. To a level of precision corresponds a standard deviation SD around the mean.
Uncertainty:	The range of uncertainty is commonly expressed as the range within which a measurement result can be expected to fall with 95% confidence i.e. ± 1.96*SD. The numerical values of uncertainty mentioned in this document represent half that range i.e. 1.96*SD. In this document, uncertainty is expressed as a percentage of the typical measured value (such a percentage is sometimes called the "coefficient of variation"). We also calculate uncertainty when the measured value itself is expressed as a percentage of the total emissions. In this case, uncertainty is a "relative" percent of the "absolute" percent of the total emissions.
Accuracy:	The bias or systematic error associated with a measurement process. The accuracy of a measuring device is affected by a number of parameters such as physical location of the instrument within a piping system, calibration, state of maintenance etc. It can be reduced to a minimum by good engineering and maintenance practices. A systematic bias is best detected by data reconciliation over the whole refinery system or a subset thereof.

3. GENERAL MONITORING METHODOLOGY

The Guidelines (Annex I, 4.2) allow for:

- Either direct measurement of GHG emissions,
- Or calculation from fuel quantity and quality data.

Direct measurement of emissions is unlikely to be used in oil refineries and is not further discussed.

For emissions from combustion in oil refineries (which have by far the largest share), calculations may be based either on individual measurement of fuel consumption and quality, or on a site carbon balance (Annex III, 2.1). The Guidelines give preference to the former method and suggest that the carbon balance approach is only to be used if it is likely to be more accurate.

The carbon balance method is impractical inasmuch as it would require detailed knowledge of carbon contents of all refinery input and output streams. Measurement of fuel consumption and quality is likely to be the most popular method.

A refinery mass balance approach may also be used and can provide an accurate estimation of fuel and loss, although the separation of these two items may cause problems.

For non-combustion emissions (mainly process), specific methodologies apply, some of which are discussed in this document. Although refineries may emit greenhouse gases other than CO_2 (methane, nitrous oxide, fluorinated compounds) their contribution in terms of CO_2 equivalent are small and their estimation is essentially site-dependent. They are therefore not discussed here.

4. INVENTORY

There are many potential sources of CO_2 emissions in a refinery. A list is included in *Annex III, 2 of the Guidelines*. This list is not quite exhaustive and is based on sources within an installation as covered by the Guidelines. In most cases a list based on type of fuel will be more appropriate inasmuch as fuel consumption will often be measured centrally rather than at each consumer. We suggest using a matrix as shown in **Table 1** to clarify the relationship between primary sources of CO_2 and emitting plant or equipment.

Table 1 Refinery CO_2 emission sources

Sources	Combustion			Process				
	Own gas (1)	Imported gas (2)	Liquid fuel	Coke		Chemical CO_2	Waste gases	Emergency releases
				Continuous	Occasional			
Typical contribution								
Boilers	X	X	X					
Process Heaters	X	X	X					
Incinerators	X	X					X	
Flares	X	X					X	X
FCC				X				
Continuous reformer								
Catalyst regeneration								
Reformers					X			
Hydrotreaters					X			
Hydrocrackers					X			
Hydrogen plant	X	X				X		
Gasifier						X		
Flexicoker						X		
Off -gases ex								
SRU							X	
Amine overheads							X	
Asphalt oxidation							X	
Fixed thermal engines	X	X	X					

(1) Including re-gassed LPG if applicable

(2) Mostly natural gas

Other very minor sources may also be present but will cumulatively be well within the 1% limit for application of the "de minimis" rule (see Annex I of the Guidelines, 4.2.2.1.4)

The crosses could be replaced by approximate percentages or ranges of total emissions to highlight the relative contribution of the various sources in relation to the definitions given in the *Annex I, 4.2.2.1.4 of the Guidelines* i.e.

Major sources, including major streams of fuels and materials are those which, if ranked in order of their decreasing magnitude, cumulatively contribute at least 95% to the total annual emissions of the installation.

Minor sources are those emitting 2.5 kt/a or less or that contribute 5% or less to the total annual emissions of an installation, whichever is the highest in terms of absolute emissions. For those minor sources jointly emitting 0.5 kt/a or less or that contribute less than 1% of total annual emissions of that installation, whichever is the highest in terms of absolute emissions, the operator of an installation may apply a *"de minimis"* approach for monitoring and reporting using his own no-tier estimation method, subject to the approval of the competent authority.

Note that the absolute emissions of individual refineries are such that the percentage rather than the tonnage threshold will apply in all refinery cases.

5. POINTS OF MEASUREMENT AND TYPE OF EQUIPMENT

Refinery fuel systems are generally complex, with many producers (especially of fuel gas) and many consumers. The material to be used as internal fuel is in some cases gathered at a central point, appropriately mixed and homogenised, and distributed to the consumers. For those cases the most appropriate point of measurement will be on the main header leading to the consumers. Such a central point of measurement can be maintained and calibrated to a higher standard than multiple meters on each consumer. On fuel gas it can also be coupled with an on-line quality measuring instrument (usually a densimeter, occasionally a chromatograph). **This grouping of sources by fuel type with a single or a small number of central measurement points is allowed for in the Guidelines (see Annex III, 2.1 a)**.

The uncertainty of a flow meter measurement depends on the measurement method (type of flow meter, compensation for variations in pressure and temperature, compensation for density) and also on maintenance and operating practices (e.g. calibration frequency). The actual “in-the-field” precision of a metering device is as a rule lower than the figure indicated by the manufacturer. The figures proposed in *Annex I, table 2 of the Guidelines* have to be considered in this light.

We propose the following figures as more representative of state-of-the-art refinery practice.

Table 2 Precision of measuring devices

Measuring device	Uncertainty %		Applicability/ Comments
	A	B	
Gaseous fuels			
Orifice meter	1 - 3	5	When compensated for temperature and pressure, up to 10 if not
Venturi tube meter	1 - 3	5	
Ultrasonic flow meter	0.5 - 1.5	2-5	Natural gas / miscellaneous gases Lowest range for complex multi-pass meters
Rotary meter	1 - 3		Not commonly applied to gaseous fuel measurement
Turbine meter	1 - 3		Not commonly applied to gaseous fuel measurement
Liquid fuels			
Orifice meter		5	
Ultrasonic flow meter	1 - 2	2	Viscous fuels can be a problem
Magnetic inductive meter	0.5 - 2		For conductive fluids Not commonly applied to fuel measurement
Turbine meter	0.5 - 2	N/A	Not suitable for fuel oils. Helicoidal bladed meters can extend the viscosity range for some crudes but doubt for fuel oil

A: as per *Guidelines Annex I, table 2*
B: Typical EU refinery

When dealing with individual measurements, the relevant uncertainty to be considered does not relate to each spot measurement, but rather to the composite effect of measurements over a full year, which is lower.

5.1. FCC COKE

Annex III, 2.1.3 of the Guidelines proposes two tiers for the estimation of FCC coke. Tier 1 refers to "*industry best practice*" which, in this case, is a stoichiometric balance over the regenerator where the CO_2 emissions are calculated directly from the intake air flow and the composition of the flue gases (O_2, SO_2, CO and CO_2). The hydrogen content of the coke can also be arrived at via the oxygen balance, the total coke burnt being then the sum of carbon and hydrogen.

The precision of this method depends on that of the measurement of the air intake and flue gas composition. A 95% confidence interval of around 10% is generally considered achievable.

Tier 2 specifies a "*heat and material balance over the catalytic cracker*". This method can only offer high uncertainty as the different components of a heat balance over the units are not known with any degree of precision and also because, as the coke typically represents some 5-7% of the feed, its estimation in this way would be through making the difference between two large numbers.

The tier hierarchy proposed by the Guidelines appears to have been misconceived. The regenerator stoichiometric balance is likely to give more precise results.

6. CARBON CONTENT AND EMISSION FACTORS

The determination of the carbon content of fuels is in many ways a new subject inasmuch as this was hitherto of no great interest.

6.1. ESTIMATION OF EMISSION FACTORS

For combustion facilities, the Guidelines call for the determination of the amount of fuel in energy terms and the use of an emission factor expressed in t CO_2/MJ (e.g. *Annex I, 4.2.2.1.1*). In practice this requires determination or estimation of the calorific value in addition to the mass of fuel. **Annex I, 4.2.2.1.6 does allow the use of mass-based emission factors (in t CO_2/t fuel), provided the fuel energy content is also reported**.

The fuel consumed in refineries is measured in terms of volume or mass, rarely in terms of calorific value. The latter can be either separately measured or estimated from a deemed composition. CO_2 emissions from burning a fuel are determined by the mass of fuel burned and its carbon content. Calorific value and carbon content are both function of the chemical composition of the fuel but there is no simple relationship between the two. As a result mass-based emission factors are more accurate (when based on actual carbon content).

CO_2 emission factors are calculated with the following formulae:

$$\text{EF [kg } CO_2\text{/kg fuel]} = (\text{C [\%m]}) / 1200 * 44$$

$$\text{EF [g } CO_2\text{/MJ]} = (\text{C [\%m]}) / 1200 * 44 / (\text{Calorific value [MJ/kg]}) * 1000$$

Generic emission factors are available from various sources such as the IPCC (see *Guidelines, Annex I, table 4*).

The IPCC factors as most published factors are expressed per unit of energy content (based on net calorific value). These factors are suitable for guidance but are, at least for certain products, not representative of the European situation. For LPG and heavy fuel oil the values appear low. The factors for pure propane and butane are 64.7 and 66.4 respectively compared to the proposed IPCC value of 63.1 (t CO_2/TJ or g CO_2/MJ, about 3.0 t CO_2/t fuel). With a typical calorific value of 40.5 GJ/t and 87-88% carbon, heavy fuel oils have emission factors around 78-79 t CO_2/TJ compared to the IPCC value of 77.4 (about 3.2 t CO_2/t fuel).

In some countries, a different set has been developed and is already in use (note that it is important to know whether the gross or the net calorific value is considered). The use of such factors may be expedient but it has to be realised that they may, in some cases, be quite far from reality. Factors based on actual circumstances will usually provide more accurate estimates than default factors. It is up to each refinery or perhaps each sector federations to balance the technical accuracy considerations against the proposed administrative rules.

The uncertainty on an emission factor (i.e. carbon content of a stream) depends on the frequency of sampling and the variability of the fuel composition. It can be determined based on historical data.

Refinery fuel gas is composed of mainly methane and ethane with variable quantities of propane and butanes as well as hydrogen. Composition can vary widely between refineries but also over a period of time when changes in the running mode of the refinery can make it desirable or necessary to include more or less of certain components. Large variations in hydrogen content are not uncommon. As an example an increase of the hydrogen volume fraction from 10 to 30% (or 1 to 3% mass) would reduce the emission factor of a typical fuel gas by about 5%.

6.2. MEASUREMENT OF CARBON CONTENTS

In the Guidelines, tier 3 demands measurement of fuel carbon content while Annex I, section 10.3 stipulates that, for such measurements, “the laboratory used to determine the composition or emission factor shall be accredited according to EN ISO 17025”.

In practice such measurement will only be practical when carried out by the refinery laboratory (particularly for fuel gas). These laboratories are as a rule ISO 9000 certified and any additional certification for the sole purpose of determining carbon contents or any other relevant measurement should be resisted.

7. FREQUENCY OF MEASUREMENT AND REPRESENTATIVITY OF SAMPLES

The legal reporting obligations of refineries with regards to the ET Directive refer to yearly data. However, most refineries will monitor CO_2 emissions at a much more frequent interval, even continuously in some cases.

For those data that are not measured continuously such as most quality or compositional data, the frequency of measurement should be adapted to the expected or observed variability with time. For example the carbon content of fuel oil from similar crude sources is not likely to significantly vary over time and sampling and measurement could be infrequent. As highlighted in section 5, the carbon content of fuel gas may, however, vary appreciably and a suitably frequent determination (direct or indirect via a quality estimator based e.g. on density) will need to be introduced.

8. DETAILED TIER REQUIREMENTS VERSUS GLOBAL UNCERTAINTY

The Guidelines specify uncertainty requirements by "tier". Article 4.2.2.1.4 specifies that "the highest tier approach shall be used by all operators to determine all variable from all sources..." However, "during the period 2005-2007, Member States should apply as a minimum the tiers as set out in Table 1, unless this is technically not feasible". Since most refineries emit > 500 kt/a of CO_2, the requirements of Table 1 of the Guidelines correspond to a large extend to highest tier requirements.

Additionally, Article 4.3.1 specifies that "the operator shall have an understanding of the impact of uncertainty on the overall accuracy of his reported emission data."

The following shows that, due to the combination of variances, the overall level of uncertainty is usually significantly less than the uncertainty of each of the individual measurements.

In a typical refinery, CO_2 emissions are generated by 8 to 15 sources[1]. Often, the distribution of CO_2 emissions between these sources is close to an 80/20 rule (typically 3/4 of emissions coming from 1/4 of sources), with two or three sources dominating the emissions.

A certain type of fuel is used to supply a number of furnaces and heaters. The total flow of that fuel is arrived at by adding (and sometimes subtracting) readings from several flow meters. The uncertainty on the total flow stems from the precision of all individual measurements. The same applies to all fuel types and to other emission sources.

Statistical analysis shows that only the major contributors to the total activity or those that have a very high uncertainty have a sizeable impact on the overall uncertainty of this activity data.

8.1. UNCERTAINTY CALCULATION METHOD

The uncertainty analysis method and algorithms are based on a simplified method recommended by the IPCC [4].

Uncertainty on a product function:

Given a function P = A * B

The uncertainty on P is $U_p = \sqrt{(U_a{}^2 + U_b{}^2)}$

This formula can be applied to estimate the combined uncertainty for the emissions from one source calculated as the product of the activity data, the emission factor and the oxidation factor (note that the uncertainty on the latter is always very low and does not have a material effect on the result).

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[1] The word "source" is used here with the same meaning as in the EU Guidelines, i.e. as a fundamental building block of an overall CO_2 emission calculation. For instance, a "source" can be a complete fuel system.

Uncertainty on a sum function:

Given a function S = A + B

The uncertainty on S is $U_s = \sqrt{(U_a * A)^2 + (U_b * B)^2} \, / \, S$

This formula applies to the estimation of the overall uncertainty for the total emissions from various sources.

In theory, this method requires that all variables used as basis in the calculation are independent. Strictly speaking, this is not true for all variables in a real case such as a complex refinery. However, by selecting the sources of emissions on the basis of fuel type, the relationship between the basic variables used in the calculation is minimised, therefore the impact of this approximation on the overall uncertainty is low. Considering that the uncertainty on the basic variables is itself only an estimate, this method is therefore considered adequate by all experts that were involved in this study.

8.2. TYPICAL REFINERY CASE

Table 3 offers an example, inspired by a real case. It includes 9 sources, of which two represent slightly over 70% of total CO_2, the largest source representing somewhat less than 50% of the total. The table shows how the uncertainty on each activity data combines with that of the corresponding emission factor to give a total uncertainty for each source. These are then combined according to the method described above. The last column shows the contribution of each source to the total uncertainty. The overall uncertainty is lower than the uncertainty on each source, and only three sources make a sizeable contribution.

Table 3 CO_2 Emissions uncertainty summary - Example

Source	% of total CO_2 Emission	Uncertainty			Weighted uncertainty %	Square of Weighted uncertainty	Contribution
	A	Activity data	Emission factor	Total (U)	U*A	$(U*A)^2 * 10^4$	Contribution
Refinery fuel gas	43.9	5.0%	3.0%	5.8%	2.6%	6.6	65%
Refinery liquid fuel	27.9	4.0%	1.2%	4.2%	1.2%	1.4	13%
Natural gas	7.8	2.9%	1.0%	3.1%	0.2%	0.1	1%
NG to SP2	0.2	4.0%	1.2%	4.2%	0.0%	0.0	0%
Imported FG	0.1	4.0%	2.4%	4.7%	0.0%	0.0	0%
Flare	1.3	25.0%	7.0%	26.0%	0.3%	0.1	1%
Hydrogen Plant	9.6	3.0%	1.0%	3.2%	0.3%	0.1	1%
FCCU coke	9.1	10.0%	11.5%	15.2%	1.4%	1.9	19%
Catalyst Regen.	0.1	4.0%	3.0%	5.0%	0.0%	0.0	0%
						10.1	

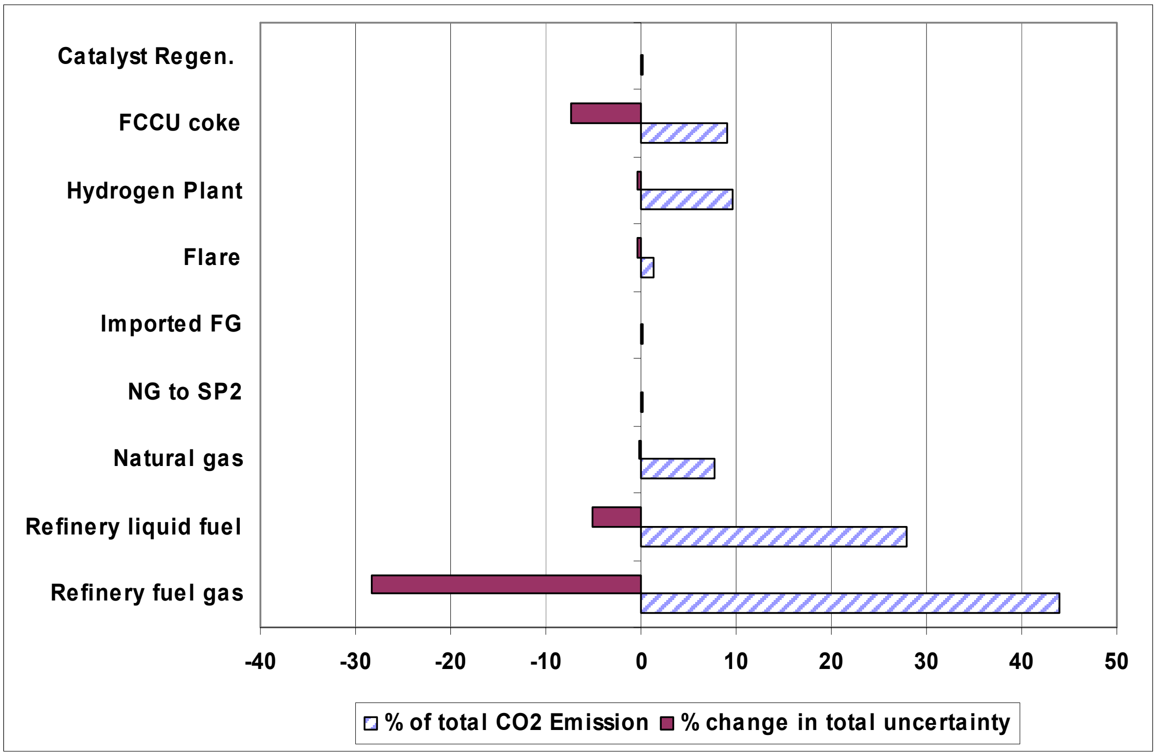
Overall uncertainty (square root of sum of squares)	**3.2%**

In this example, tier requirements on activity data are not met for most of the sources. Actual plant information indicates that this is indeed often the case. Our experience is also that the sources for which the tier requirements can easily be met are usually small and do not contribute in any significant way to the overall uncertainty.

The overall uncertainty is lower than on any single activity and, in this case, is within the range of the overall uncertainty indicated in *Annex I, table 3 of the Guidelines*, or 3.5% (liquid and gaseous fuels with varying composition, emissions exceeding 500 kt/a). This may of course not always be the case and each refinery will have to carefully consider its own circumstances. This type of calculation does, however, highlight that the overall uncertainty is lower than what could have been anticipated from the single activity uncertainties.

Improvement in the uncertainty of individual sources only has a material effect when such sources have a significant contribution and/or have a very poor uncertainty to start with. This is illustrated in **Figure 1** for our example.

Figure 1 Effect of a 50% reduction of the uncertainty on each individual source on the overall uncertainty



8.3. RECOMMENDATION

According to *Annex I, 4.3.1 of the Guidelines*, an overall uncertainty analysis of CO_2 emissions must be carried out by the Operator of a facility that falls within the scope of the European Emission Trading Scheme. Such analysis rests on the definition of the uncertainty of each measurement used in the CO_2 calculation, which is also required according to the Guidelines, since the Operator must report to which tier each measurement corresponds. We can conclude that an overall uncertainty analysis will therefore be required in any case. It has actually already been requested by the Authorities in some EU Member States.

The example provided here demonstrates that such overall uncertainty calculation is feasible. It provides significant insight into the most efficient way to improve the uncertainty on the reported overall CO_2 emissions and to enable compliance with the intent of the Guidelines and of the Emissions Trading Directive at minimum cost. Although the uncertainty calculation method presented here is somewhat simplified, we are confident that it will be acceptable to verifiers and that it will help in providing a level playing field.

It is therefore recommended to use this approach to demonstrate that a satisfactory level of uncertainty may be achieved on the total emissions even when higher tier requirements are not met on individual measurements.

9. REFERENCES

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APPENDIX 1 GASEOUS AND LIQUID FUEL MEASUREMENT UNCERTAINTY PRACTICAL ASPECTS

1. Fiscal standards and uncertainty

The fiscal standard (ISO 5167) specifies very precisely what is required, and provides for installation configurations representing up to 0.5% additional uncertainty (as calculated by ISO 5168) in terms of deviation from the standard.

The important point to note here is that there is no “standard” for calculating the uncertainty in non-fiscal applications.

2. Orifice plate inspection

Orifice plate meters that are not in custody transfer services are not, as a rule, fitted in such a way that they can be inspected when the plant is running. This means that inspection is only possible during shutdowns, typically at intervals of 3 to 5 years depending on the type of plant. For practical reasons and because these items are not directly related to safety issues, only selected meters will be inspected during a given shutdown so that a certain meter may not be inspected for 10 years or more. During that period, orifice plate wear may significantly reduce its accuracy.

3. Orifice plate sizing

Typically orifice plate meters offer a turn down ratio of only 2:1. If process conditions have changed since the meter was installed (which may be 20 years or longer), the flow rate may have changed significantly. However it is not possible to re-range the meter (by change of beta ratio) without a change in the orifice plate diameter. It is possible to have multiple orifice plate meters in parallel but these are very expensive

4. Secondary instrumentation (T, P and density)

- Is probably also subject to the same low maintenance regime.
- Some installations have only pressure measurement or no secondary measurement at all, and fixed values have to be assumed, which may not be appropriate if process conditions have changed significantly from the design conditions.
- Corrections for P, T and density are required which requires a correction in the meter flow computer itself, the DCS or mass balance/accounting system
- Although a correction for T is required, it is actually the least significant value because the flow correction factor is a function of absolute temperature i.e. T+273°C.

Examples of use of incorrect DCS values are:

- Use of burner tip pressure rather than the line pressure.
- Use of a temperature the other side of a heat exchanger.

- Use of header density for a process stream of unknown density (usually a consumer which is also a producer).
- Device outputs a relative density (i.e. relative to air) whereas DCS assumes the output is absolute density, which can introduce an error of ~ 20%.

5. Process conditions

- Changes to edge sharpness and liquid build-up upstream of the throat can affect the shape of the vena contracta, and therefore accuracy of flow as the dP measurement is made in a fixed location downstream of the throat.
- Particulates can be aggressive and pit the plate surface, reducing edge sharpness.
- Liquid build up, amines (combining with particulates) can all be difficult metering situations.

6. Potential constraints to moving to next tier

- Next shutdown window may not be for 5 years.
- The planning window for scheduling maintenance work is usually 12-18 months ahead of a shutdown.
- Capital expenditure approval.

7. Other fuel gas metering technologies

- Vortex meter.
- The principle involves a bluff body introduced into the flow to create vortices downstream, with flow rate is proportional to frequency of the vortices.
- Problems can occur in dirty gas service, as the bluff body acquires a cone-shape.
- Build-up of particulates, i.e. it becomes aerodynamic and vortices are reduced.
- V-cone meter.
- Similar to the Orifice plate meter, in that it is a differential pressure, but the V-Cone shape means it is good for dirty gas service and can be designed to accommodate large flows, i.e. it would be suitable for service downstream of a mix gas drum.
- Ultrasonic meter.
- 1, 2 or 5 path ultrasonic device, plus additional tappings for P and T. Principle is based on time of flight (speed of sound) across the metering tube. General experience is good, although liquid build up can give a double-bounce effect which may not be corrected for in the software.

8. Liquid fuel gas

Although normally a straightforward measurement of flow, some systems have liquid fuel lines on constant circulation to a tank. A duel-fired liquid fuel/fuel gas burner may therefore be deemed to be on liquid fuel service by means of valve status in the

DCS rather than direct measurement of flow. One solution to this could be portable ultrasonic metering, measured externally. This would, however, still require removal of insulation and suitable power.

9. Density measurement (gas)

This is usually achieved by on line density meters and periodic sampling. Constraints are:

- Density meters may not be available on all streams.
- Manual sampling may be carried out only monthly – the ideal is every 2-3 days if the process stream is variable.
- Sample points may not be available.
- Operator training in sampling procedures.