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GUIDANCE ON PROVISION OF UK NATURAL GAS SUPPLY QUALITY DATA RELEVANT TO THE EU EMISSIONS TRADING SCHEME – FOR EMISSIONS PRIOR TO JANUARY 1st 2013

1. INTRODUCTION

In 2005 DEFRA requested from then UK Gas Transmission System Operator (TSO), Transco, information on UK natural gas carbon dioxide emission factor (CEF) and related data. This request followed the European Commission Decision of 29th January 2004, which established guidelines (known here as "MRG2004") for the monitoring and reporting of greenhouse gas emissions pursuant to European Directive 2003/87/EC. The 2003 Directive established a scheme for greenhouse gas allowance trading within Europe.

The key requirement of the guidelines for natural gas consuming activities is to report annual emissions of carbon dioxide and this is calculated as the product of the quantity of natural gas consumed ("activity data"), its carbon Emissions Factor (CEF) and an oxidation factor (to allow for less than complete combustion). MRG2004 also required understanding of the uncertainty associated with the monitoring of reported annual emissions, as well as reporting of the CV and energy consumed.

In 2007 the European Commission published a further Decision with revised guidelines (known here as "MRG2007") which replace MRG2004 and incorporate changes arising from experience gained in the first phase of operation of the EU ETS.

This note provides information about the UK natural gas industry in general, how the UK CEFs for natural gas have been developed and about typical natural gas metering systems currently in place. The privatisation of the gas supply industry means that there is no single UK TSO and Transco are no longer responsible for this note. This note is provided for additional information only; more specific requirements are provided in the installation's approved M&R plan, the Commission's M&R Guidelines and the UK Government's Guidance on Annual Verification. This note is applicable to the Monitoring and Reporting of carbon dioxide (or equivalent) emissions until 31 December 2012.

MRG2004 set out various monitoring tiers, subsequently modified in MRG2007, which demand increased accuracy of monitoring the higher the monitoring tier. The minimum expected monitoring tiers for natural gas fired plant (following publication of MRG2007) are set out in Table 1 below.

Table 1: Monitoring tiers for natural gas fired installations [see note 1]

Category		A	B	C
Installation size	ktCO2 pa million therm pa [see note 2] m^3/h [see note 2]	≤ 50 ≤ 9.21 ≤ 2,477.4	>50-500 >9.21-92.10 >2,477.4-24,774	>500 >92.10 >24,774
Fuel flow	Tier Uncertainty %	2 ±5.0	3 ±2.5	4 ±1.5
Calorific value	Tier Approach	2a or 2b UK GHG Inventory or fuel supplier	2a or 2b UK GHG Inventory or fuel supplier	3 Measured
Emission factor	Tier Approach	2a UK GHG Inventory	2a UK GHG Inventory	3 Measured
Oxidation factor	Tier Value	1 1.0	1 1.0	1 1.0

Notes to Table 1:

1. *Table 1 is based on information published in Table 1 of MRG2007.*
2. *Installation size as million therm (gross) pa and m^3/h of natural gas equivalent is estimated using a* mean *(gross)* CV of 39.48 MJ/m3 (standard deviation 0.459 MJ/m3) and the mean CEF of 51.12 t-CO2/TJ (standard deviation 0.599 t-CO2/TJ) *(GB estimated figures for 2010) and an oxidation factor of 1.*
3. *For large emitters of carbon dioxide (>500 ktCO2 pa) emissions must be based on measured CEF and measured calorific values specific to the installation concerned.*
4. *For intermediate and smaller emitters, carbon dioxide emissions can be based on a country-specific fixed CEF as reported by the Member State in its latest national inventory submitted to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC). For natural gas, the UK Government has determined that the factors used shall be those reported (for each local distribution zone) in the table provided by DEFRA/DECC based on quality assured gas transporter data for the previous year. These factors will be used in the next national inventory submitted to the UNFCC. This is discussed further in the Guidance on Annual Verification[1].*
5. *Table 3 of MRG2004 gave informative typical overall uncertainties in CO2 emissions for each category of installation. These were withdrawn in MRG2007 and a more detailed section on uncertainty provided. Consequently the typical overall uncertainties in Issue 0 of this briefing note have been removed.*

2. GAS SUPPLY IN THE UNITED KINGDOM

[1] Dept of Energy and Climate Change. EU Emissions Trading System. Guidance on Annual Verification for emissions from stationary installations emitted before 1 January 2013. Version 6 February 2012. Available from DECC website.

2.1. THE UK GAS TRANSMISSION AND DISTRIBUTION SYSTEMS[2]

The TSO is the owner, operator and developer of the high pressure National Transmission System (NTS). Lower-pressure distribution systems, fed from the NTS, are owned, operated and developed by Distribution Network Operators (DNO). The Distribution Networks and Gas Transmission System are the main licensed gas transporters in Great Britain.

The TSO receives piped natural gas into the NTS from coastal reception terminals around Great Britain and liquefied natural gas (LNG) from LNG terminals.

Two interconnectors, one to Belgium and one to the Netherlands, link the NTS to continental Europe's high-pressure gas grid.

Gas received into the NTS is delivered to the Distribution Networks for delivery to the meters of more than 21 million industrial, commercial and domestic consumers, on behalf of approximately 70 gas shippers. The entire GB network is made up of around 275,000 km of pipeline, comprising around 6,600 km of high pressure national and regional transmission systems, and the remainder as lower pressure local distribution systems. Gas is pumped through the high pressure NTS by 24 compressor stations located around the country.

A further two interconnectors supply gas from the NTS in Scotland to Ireland and Northern Ireland. Northern Ireland currently receives gas from Scotland through the Scotland-Northern Ireland Pipeline (SNIP) system, owned by a 3rd party, which is fed into gas distribution networks owned and operated by 3rd parties. In addition, a South-North pipeline can bring further gas into Northern Ireland, although the transmission regime in Northern Ireland requires that the SNIP capacity must be fully booked before any capacity is booked on the South-North pipeline. Most of this gas would be gas that is in turn supplied from Scotland through the Scotland-Ireland interconnector and so the contribution from non-Scottish sources is expected to be small (in terms of impact on carbon dioxide emission factor).

The Stranraer network in Scotland is also supplied with gas from the SNIPS prior to export.

In Scotland there are two further smaller gas networks that are separate from the UK gas transportation system:

- The four Scottish Independent Undertakings (SIU) networks totalling around 91 km of pipes, which are owned and operated by a DNO and supply around 6,500 consumers with regasified Liquefied Natural Gas (LNG) which is transported by road tankers from TSO owned LNG Storage facilities.

The Uniform Network Code (UNC), set up following privatisation of the UK Gas Industry, governs how each party may act. Gas transporters are obliged to operate their systems efficiently and safely. Shippers are required to ensure delivery of their daily-nominated quantities and as a result considerable trading of nominated quantities may result. Gas transporters therefore have no control over where gas enters their systems; shippers nominate in advance how much and where gas will be entering on each "gas day"[3].

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[2] The terms "Network" and System" are often used interchangeably in the gas industry. For the purposes of this note the term "Distribution System" refers to the pipework and equipment used to transport natural gas and "Distribution Network" refers to the organisation that owns operates and develops the Distribution System.

[3] Under the UNC the "gas day" is the 24-hour period beginning at 6.00am each morning.

The Gas Safety (Management) Regulations were introduced shortly after privatisation in 1996. Amongst other things, these regulations set out minimum gas quality requirements to ensure safe operation of the system and appliances used by consumers. Gas transporters are obliged not to convey gas that does not comply with these minimum gas quality requirements.

2.2. CALORIFIC VALUE AND ENERGY BILLING

A relatively small number of gas consumers receive bespoke supplies of gas direct from the NTS.

The vast majority of gas consumers receive gas through the lower pressure systems and transfer of gas from the higher-pressure NTS to the lower pressure distribution systems occurs at around 111 NTS offtakes throughout the country, 77 of which supply gas quality data. Great Britain is divided into twelve charging areas (known as Local Distribution Zones, or LDZs) and most consumers are billed on the basis of the Calorific Value (CV) of gases entering (through the NTS offtakes) the LDZ in which they are located. Each Distribution Network is associated with one or more Local Distribution Zones (LDZs).

Each day the TSO on behalf of the Distribution Networks, calculates for each LDZ a charging area CV, based on the daily average CV determined for the inputs to (and in some cases, outputs from) the LDZ. The manner in which the daily average CVs are determined, and the charging area CV is calculated, is set out in the Gas (Calculation of Thermal Energy) Regulations 1996 and Amendments 1997 and 2002.

Gas transporters do not buy or sell gas, other than that necessary to keep their systems in balance or for their own use (powering compressors, heaters, etc.). Gas consumers buy their gas from gas traders, who in turn arrange transportation through gas transporters' networks using gas shippers. The area CVs calculated each day by the TSO are passed on to gas shippers and then on to gas traders who use them to calculate the final consumers' gas bills.

For most consumers, daily charging area CVs are calculated using the flow-weighted average CV (FWACV) methodology, which requires that charging area CV is the lower of:

- The flow-weighted average of all daily average CVs determined for all relevant inputs to and outputs from the LDZ, and
- The lowest daily average CV determined for all relevant inputs to the LDZ, plus 1.0 MJ/m^3.

This second value caps the charging area CV to no more than 1.0 MJ/m3 than the lowest daily average CV of the sources of gas to the LDZ on a particular day. The cap was introduced in the Gas (Calculation of Thermal Energy) Regulations Amendment 1997. Note that operation of the cap could introduce a bias error in carbon dioxide emissions if an energy-based CEF is employed with activity data based on capped CVs (see Section 3.3.4).

Exceptions to the FWACV charging methodology are: some very large users, who are billed on a site-specific CV basis; and consumers supplied through the SIU and Stornaway networks, who are billed on a Declared Calorific Value (DCV) basis (i.e., the minimum CV of gas to be supplied is declared in advance of the billing period). DCV billing will also introduce bias errors in carbon dioxide emissions if an energy-based CEF is employed with activity data based on energy bills.

3. PROVISION OF CARBON DIOXIDE EMISSION FACTOR DATA

3.1. CARBON DIOXIDE EMISSION FACTORS FOR NATURAL GAS IN GREAT BRITAIN

The CEF employed in calculating carbon dioxide emissions from natural gas consuming installations in Great Britain will be either a site-specific value (Tier 3 compliance) or a fixed factor

(Tier 2 compliance), based on compositional analysis. Emitters connected to gas transporters' networks fall into one of four categories according to the measurements available to them:

- Large loads (i.e. >92 million therm pa. or approximately equivalent to 500ktonne CO2 emissions per year) connected to the NTS or a distribution network that have gas composition continually analysed using a Daniels Model 500 process gas chromatograph owned and operated by a gas transporter.
- Large loads connected to the NTS or a distribution network that have no gas compositional analysis.
- Large loads connected to NTS or LTS that have gas composition continually analysed using equipment owned and operated by the emitter
- Intermediate and small loads (i.e., <92 million therm per annum) for which a fixed CEF may be employed.

3.2. TIER 3 EMISSION FACTOR COMPLIANCE (CATEGORY C INSTALLATIONS)

Compliance with Tier 3 requires CEF of the natural gas combusted to be determined by the operator, an external laboratory or the fuel supplier. In essence this will most likely entail one of two approaches:

- Taking of spot gas samples over the period in question, which are subsequently analysed by an external laboratory. The sample(s) taken are required to be representative and free of bias. The laboratory performing the analysis should be accredited against EN ISO/IEC 17025.
- Analysis using a process or online analyser. In this situation the operator of the system shall meet the requirements of EN ISO 9000. The systems shall be calibrated with natural gas calibration standards certified by laboratories accredited to EN ISO/IEC 17025 and, where applicable, instrument initial and annual evaluation according to EN ISO 10723 by laboratories accredited to EN ISO/IEC 17025.

Information on laboratories holding suitable accreditation to EN ISO/IEC 17025 can be obtained from the United Kingdom Accreditation Service.

The sampling frequency is required by MRG2007 to be such that it ensures that the annual average of the CEF is determined with a maximum uncertainty less than one-third of the maximum uncertainty required by the applicable activity Tier level. For activity Tier 4 (with an activity data maximum uncertainty of 1.5%) this suggests that maximum uncertainty in the CEF shall be 0.5%. MRG2007 also suggests a default minimum sampling frequency of weekly for natural gas (see Table 5 of MRG2007).

3.3. TIER 2 EMISSION FACTOR COMPLIANCE (CATEGORY A AND B INSTALLATIONS)

3.3.1. ANNUAL UK NATURAL GAS DATASET

Tier 2 compliance requires use of a country-specific fixed CEF. The vast majority of consumers are supplied with gas from the lower-pressure distribution systems, so it is appropriate to employ the process gas chromatographic data available at the NTS offtakes to derive appropriate values. Each instrument typically analyses gas composition with a cycle time of four minutes. Some instruments have multi-stream capability to permit analysis of up to three separate sample points so for a particular sample point between around 100 and 300 analyses are conducted each day.

Each analysis result is stored locally and once per day transferred back to a computer database maintained by the Distribution Network responsible for the relevant instrument/charging area. As there are in excess of 100 instruments located throughout the

UK, there are around 300x365x100 or in excess of 10 million gas analyses produced each year and annual CV and CEF data are calculated automatically from the entire dataset.

The exception to this situation is the annual data for the SIU, which is derived from analysis of samples taken at each reception point. For the SIU networks the LNG samples are taken monthly.

3.3.2. QUALITY ASSURANCE RELATING TO TIER 2 DATA SUPPLY

The compositional data employed in calculating CEF for Tier 2 requirements comes from the process gas chromatographs operated by the Distribution Networks. The quality assurance regime covering the approval, installation, verification, operation and maintenance of the process gas chromatographs is based on the demanding requirements set by the industry regulator Ofgem.

- Instrument type approval. Ofgem has approved the use of the Daniels Models 700 and 500, following extensive testing of the instruments. The software employed for data capture and storage has similarly been tested and approved by Ofgem.
- Approved contractors perform installation and initial verification is carried out by performance evaluation to EN ISO 10723:2002 by an approved service provider that is accredited to EN ISO/IEC 17025.
- The instruments are calibrated daily using a calibration standard of composition approved by Ofgem. A laboratory accredited to EN ISO/IEC 17025 certifies these standards.
- Alarm settings are set to the analytical range for each component agreed with Ofgem following type approval. Values obtained should the instrument be in an alarm condition are rejected.
- The instrument is verified monthly by analysis of a natural gas test gas of known CV. Ofgem’s service provider determines the CV of the monthly test gas.
- An approved service provider carries out repairs and maintenance. Following repairs to faults in the detection system, an instrument is verified by performance evaluation to EN ISO10723 by an approved service provider that is accredited to EN ISO/IEC 17025.

The above regime meets or exceeds the requirements of MRG2007 in terms of operators of online gas analysers and gas chromatographs, including the annual inter-comparison requirements of Section 13.5.3(b).

3.3.3. PROPERTY CALCULATIONS

From the annual gas composition dataset CV (gross and net) and CEF (energy based, gross and net, and quantity based) are calculated. CVs are calculated according to BS EN ISO 6976:2005. There is currently no National, European or International standard covering calculation of CEF from composition but in the UK the methodology adopted by the Distribution Networks is an adaptation of that used in BS EN ISO 6976:2005 and is given in Appendix A and approved by OFGEM for fiscal purposes.

The resultant datasets comprises for each LDZ and the UK as a whole, a distribution of calculated properties (CEFs, CVs) from which mean and standard deviation are calculated[4].

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[4] To follow the full BS EN ISO 6976:2005 methodology, the fixed CEF would be estimated as a weighted mean, in which individual CEFs are weighted by the instantaneous flowrate of natural gas at the time of analysis. In practice this was found to offer little improvement in accuracy and use of un-weighted means reduces considerably the complexity of data processing.

3.3.4. USE OF CEF DATA

For those emitters for whom a site-specific CV for their gas supply is determined by a gas transporter, calculation of an energy-based CEF may be appropriate. However those billed on the basis of daily charging area CV could introduce a bias error in CO2 emission, if the CV cap in charging area CV comes into play during the year (daily charging area CV may never be more than 1 MJ/m^3 greater than the daily average CV of the lowest source into an LDZ on that day). For these emitters a quantity-based CEF may be more appropriate.

Annual CEF and CV data is provided to DEFRA/DECC by gas transporters and is accessible from the DEFRA/DECC website within the table of emission factors and CVs for use in the EU-ETS. Both National and LDZ data are provided, however, emitters must use LDZ data and not National values, to minimise national under-reporting through selective use of lowest value for CEF. CEFs reported for Stranraer are currently suitable for installations located in Northern Ireland. The gas transporter(s) in Northern Ireland will verify annually the suitability of Stranraer data.

Currently, LDZ CEF data for the previous year is employed for reporting emissions data for the whole of the following year (e.g. 2008 reporting for the EU-ETS employed CEFs calculated for natural gas transported in 2007). This approach ensures use of the most accurate data consistent with no risk to emitters associated with potential variation in CEFs within the reporting year.

The above approach represents an exception adopted solely for natural gas CEFs and CVs. For other fuels and process emissions, operators applying Tier 2 factors must use the CEFs and CVs in the latest UK GHG Inventory submitted to the UNFCCC. This means that for the 2008 reporting year operators employed emission factors from 2006, as contained in the 2008 UK GHG Inventory submitted to the UNFCCC in April 2008. The relevant emission factors for EU-ETS reporting are summarised in the spreadsheet available from the DEFRA/DECC website. Further explanation of this is contained in the *Guidance on Annual Verification*.

4. ACTIVITY DATA

4.1. MRG2007 GUIDELINES

Table 1 sets out the uncertainty in annual activity data monitoring required for natural gas fired combustion plant for Categories A, B and C.

Larger installations accuracy of flow measurement can agreed between gas supplier and user, but would normally be based on Department of Business, Innovation and Skills (BIS) *Guidance Notes for Petroleum Measurement under the Petroleum (Production) Regulations (2003 Issue 7)* These specify that mass flow measurement should have an overall uncertainty of +/- 1.0%.

For other installations, the Institution of Gas Engineers and Managers *Gas Measurement Procedures Document (IGE/GM/8 Parts 1-5)* includes guidance on expected accuracy in non-domestic metering installations where flow rate exceeds 6 m3/hr and inlet pressure does not exceed 38 barg. The expected accuracy of installations will depend on the type of metering equipment installed. This is discussed further in Section 6.

4.2 NATURAL GAS METERING IN GREAT BRITAIN

Historically, most non-domestic metering installations in Great Britain were owned by the gas transporter and installed by an Ofgas Registered Gas Meter Installer (RGMI) or, more-recently, an Ofgem Approved Meter Installer (OAMI). The introduction of competition in metering means that the market has opened to allow ownership and/or transfer of meter installations to other parties, including Meter Asset Management (MAM) companies and consumers.

The de-regulation of the natural gas metering market was supported by the introduction of Ofgem Codes of Practice (CoP) for MAMs. Conformance to the relevant Ofgem CoP was a necessary condition for any MAM to operate. As part of a review of gas metering arrangements in 2004, a gas industry representative group (including Ofgem, IGEM and HSE) developed the Code of Practice for Gas Meter Asset Managers (MAMCoP), which brings together all relevant GB documentation and legal requirements covering the complete life cycle of gas meter installations. MAMs are required to register with the Meter Asset Managers Registration Scheme. The initial assessment and on-going management of the registration process is managed by Lloyd's Register. Accredited MAMs are listed on the Lloyd's Register websiteand are able to display the MAMRS quality mark.

The MAMCoP expands on the requirements laid down in Ofgem CoP 1/a, 1/b and 1/c (which primarily cover the installation of the meter installation only) by specifying the requirements for all stages of the meter installation's life. For the purpose of OAMI registration and compliance with Condition 34 of the Standard Conditions of Gas Suppliers Licences, conformance with the applicable section of the MAMCoP is deemed to be equivalent to conformance with the relevant Ofgem CoP. The Ofgem CoPs will eventually be withdrawn.

5. UNCERTAINTY

5.1. ACTIVITY DATA

Table 1 lists the uncertainty requirements of MRG2007 for each Tier.

Guidance on uncertainty is provided in a joint note produced by the Environment Agency, the Scottish Environment Protection Agency and the Northern Ireland Environment and Heritage Services (now the Northern Ireland Environment Agency)[5]. The note provides guidance on practical methods for meeting the uncertainty requirements of Section 7.1 of MRG2007. The approach includes suggestion (in Annex 1) of a list of "standard"[6] measurement uncertainties for the most common measurement instruments. However, the note does draw attention to situations in which there may be dispensation from the need to carry out detailed uncertainty assessments (see below).

5.2. CARBON DIOXIDE EMISSION FACTOR

Minimum uncertainty requirements with respect to activity data are set out for each tier, but no specific requirements are set out for either overall uncertainty, or uncertainty in CEF or Oxidation Factor, other than a requirement that for Tier 3 compliance, sampling method and frequency of analysis shall be designed to ensure that the annual average of the relevant parameter is determined with a maximum uncertainty of less than one-third of the maximum uncertainty which is required by the approved tier for the activity data for the same source stream.

[5] Competent Authority Interpretation of the Main Uncertainty Analysis Requirements resulting from the Revised Monitoring & Reporting Guidelines (MRG 2007).

[6] Note that "standard uncertainty" in this context is better regarded as "typical uncertainty" and does not mean uncertainty expressed at the standard deviation level, which is the generally accepted usage.

The TSO expanded uncertainty (probability level around 95%) in CEF determined from composition to be around 0.1% for typical natural gases using the process gas chromatographs employed by the Distribution Networks. The uncertainty budget for this calculation took into account the uncertainty in its calibration standards, the uncertainty in the response of the instrument to the calibration standard and the uncertainty in the response of the instrument to the sample. Typical expanded uncertainty in CV is around 0.05%. Sampling frequency is typically once every four minutes – well in excess of the minimum frequency suggested by MRG2007 for natural gas (weekly).

5.3. DISPENSATION FROM PERFORMING UNCERTAINTY ANALYSES

Section 7.1 of the MRG does provide for dispensation from performing uncertainty analyses in some situations that are relevant in the context of natural gas combustion in the UK:

a) Installations with low emissions, i.e. less than 25 ktonnes CO2 per annum. This is equivalent to natural gas usage of around 4.1 million therms per annum, or 1404.2 m^3/h.
b) Competent authorities may permit the determination of the annual fuel flow by the operator based solely on the invoice amount of fuel without further individual proof of associated uncertainties provided that:
    i. The fuel is a commercially traded fuel.
    ii. National legislation or the demonstrated application of relevant national standards or international standards ensures that respective uncertainty requirements for activity data are met for commercial transactions.

Regarding point b) i above, natural gas qualifies within MRG2007 section 2.2(f) definition as a commercially traded fuel.

Regarding point b) ii above, the requirements of the Gas (Meters) Regulations 1983 and more recently the Measuring Instruments (Gas Meters) Regulations 2006, together with the Quality Framework associated with the Ofgem Meter Asset Managers Registration Scheme, could be regarded as demonstration that respective uncertainty requirements for activity have been met.

Section 10.3.2 of the MRG does require that relevant measurement equipment is calibrated, adjusted and checked at regular intervals. It also provides for alternative (quality) control activities to be identified in the measurement plan if components of the measurement plan cannot be calibrated. Maintenance of meters is carried out in a manner and frequency in accordance with the manufacturers' instructions. Note that diaphragm meters typically require no maintenance. Electronic gas volume conversion systems are maintained in accordance with the IGEM standard IGE/GM/5 "Selection, installation and use of electronic gas volume conversion systems".

APPENDIX A: CALCULATION OF EU ETS PARAMETERS

1. CARBON DIOXIDE EMISSION FACTORS

As CEF can be calculated on a number of bases, the starting point for calculation is to establish the CEF on a molar basis, CEF(m):

$$CEF(m) = M_{CO2} \sum_{i=1}^{i=N} Y_i C_i \qquad \text{(A1)}$$

Where M_{CO2} is the molar mass of carbon dioxide[7] and Y_i and C_i are the mole fraction and pure component carbon dioxide emission factors for the *ith* component. Numerically C_i is equal to the number of carbon atoms in a molecule of the *ith* component.

Conversion to emission factor on alternative bases is accomplished by division of CEF(m) by the respective molar property for the natural gas.

So for calculation on a gross calorific value basis:

$$CEF(g) = \frac{CEF(m)}{GCV(m)} \qquad \text{(A2)}$$

Where GCV(m) is the gross calorific value on a molar basis.

For calculation on a net calorific value basis:

$$CEF(n) = \frac{CEF(m)}{NCV(m)} \qquad \text{(A3)}$$

Where NCV(m) is the net calorific value on a molar basis.

And calculation on a quantity basis:

$$CEF(q) = \frac{CEF(m)}{V(m)} \qquad \text{(A4)}$$

Where V(m) is the molar volume at metric standard conditions (15^{o}C, 1.01325 bar).

2. CALORIFIC VALUES

Gross calorific value and net calorific value are calculated according to ISO 6976:1995 Natural Gas – Calculation of calorific values, density, relative density and Wobbe index from composition.

[7] The value for molecular weight of carbon dioxide is taken to be 44.010 g/mole, based on the Table of Atomic Weights of the Elements 2007, IUPAC Commission on Atomic Weights and Isotopic Abundances, and incorporates a value of 12.0107 for the atomic weight of carbon. Note that MRG2007 incorporates an older (pre-1995) value of 12.011 in its requirement to use a factor of 3.664 to convert carbon into carbon dioxide.