Joint Environmental Programme, Guidance for the Monitoring and Reporting of CO_2 Emissions from Power Stations, EUETS Phase 2

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Summary

During the first compliance cycle of the CO_2 trading scheme which commenced in January 2005, operators, verifiers and competent authorities of member states have gathered first hand experience of monitoring, verifying and reporting following the Phase 1 EU Guidelines (Commission Decision 2004/156/EC of 29/1/04). As a result of a review of the Guidelines by the Commission, Decision 2004/156/EC has been replaced with EU Commission Decision of 18/07/2007. The requirements of this Decision are to apply from 1st January 2008.

The current EU Guidelines set out detailed criteria for the monitoring, reporting and verification of CO_2 emissions resulting from the activities listed in Annex I of Directive 2003/87/EC (referred to below as the Directive), based on the principles set out in Annex IV and Annex V of the Directive.

This document represents the overall monitoring framework to be used by power industry Joint Environmental Programme members from 1st January 2008 and interprets the EU Guidelines for the calculation of CO_2 emissions from power station combustion installations with a rated thermal input exceeding 20 MW as listed in Annex I to the Directive. The document has been reviewed by the Environment Agency in order to agree any changes necessary to maintain conformity with the EU Guidelines.

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1. Introduction

During the first compliance cycle of the CO_2 trading scheme which commenced in January 2005, operators, verifiers and competent authorities of member states have gathered first hand experience of monitoring, verifying and reporting following the Phase 1 EU Guidelines (Commission Decision 2004/156/EC of 29/1/04). The Commission undertook to review the Phase 1 Guidelines by 31/12/2006 taking into account experiences gained, and this review concluded that changes were required in order to render the Guidelines more clear and cost-efficient. As a result of this review, Decision 2004/156/EC has been replaced with EU Commission Decision of 18/07/2007 (Phase 2 EU Guidelines, referred to hereafter as EU Guidelines). The requirements of this Decision are to apply from 1st January 2008. Note that there is an intention for further review by 1st January 2010.

The current EU Guidelines set out detailed criteria for the monitoring, reporting and verification of CO_2 emissions resulting from the activities listed in Annex I of Directive 2003/87/EC (referred to below as the Directive), based on the principles set out in Annex IV and Annex V of the Directive.

This document represents the overall monitoring framework to be used by power industry Joint Environmental Programme members from 1st January 2008 and interprets the EU Guidelines for the calculation of CO_2 emissions from power station combustion installations with a rated thermal input exceeding 20 MW as listed in Annex I to the Directive. The document has been reviewed by the Environment Agency and the Scottish Environment Protection Agency (SEPA) in order to agree any changes necessary to maintain conformity with the EU Guidelines.

One fundamental component of the monitoring plan is the identification of tiers for the determination of activity data, emission factors and oxidation factors. The increasing number of the tiers reflects higher levels of accuracy, with the highest numbered tier as the preferred tier. Where possible, this document identifies the most suitable methodologies for calculation of emissions and assigns appropriate tiers for power generating installations. However, certain requirements will be at a site specific level and whilst not covered in this document must be addressed in the site monitoring plan. This document is intended for use by Power Stations firing solid, liquid and gaseous fuels. It is equally relevant for conventional, combined cycle and Combined Heat and Power (CHP) installations. In addition, the document sets out guidance for the calculation of process CO_2 emissions from Flue Gas Desulphurisation (FGD) Plant.

This document is based on the following principles as delineated in the EU Guidelines:-*Completeness*. Monitoring and reporting for an installation shall cover all process and combustion emissions from all emissions sources and source streams belonging to activities listed in Annex 1 of the Directive and of all greenhouse gases specified in relation to those activities, while avoiding double-counting.
Consistency. Monitored and reported emissions shall be comparable over time, using the same monitoring methodologies and data sets. Monitoring methodologies can be changed in accordance with the provisions of these guidelines if the accuracy of the reported data is improved.
Transparency. Monitoring data, including assumptions, references, activity data, emission factors, oxidation factors and conversion factors are obtained, recorded, compiled, analysed and documented in a manner that enables the reproduction of the determination of emissions by the verifier and the Competent Authority.

Trueness. The emission determination shall be systematically neither over nor under true emissions. Sources of uncertainty shall be identified and reduced as far as practicable. Calculation and measurement of emissions should exhibit highest achievable accuracy. All metering and other testing equipment used to report monitoring data shall be appropriately applied, maintained and calibrated, and checked. Reported emissions shall be free from material misstatement, avoid bias in the selection and presentation of information, and provide a credible and balanced account of an installation's emissions.
Cost effectiveness. Monitoring and reporting of emissions aims for the highest achievable accuracy, unless this is technically not feasible or will lead to unreasonably high costs.
Faithfulness. A verified emissions report shall be capable of being depended upon by users to represent faithfully that which it either purports to represent or could reasonably be expected to represent.
Improvement of performance in monitoring and reporting emissions. The process of verifying the emission reports shall be an effective and reliable tool in its support of quality assurance and quality control procedures, providing information upon which an operator can act to improve its performance in monitoring and reporting emissions.

Following the review of the Phase 1 EU Guidelines, there have been some significant changes made to the current version of the EU Guidelines, and some of these that are more relevant to the utility industry are highlighted below – further details on the changes are discussed in the relevant sections within this document.

The specified content of the monitoring plan has been expanded considerably to include several new requirements including a description of the calculation/measurement based methodology used (inclusive of proposed mathematical computations, equations and factors), together with evidence to demonstrate compliance with uncertainty thresholds. There have also been major changes to requirements on operators to establish, document, implement and maintain effective data acquisition and handling activities, control systems and activities, which also need to be described in the monitoring plan. Changes in content require complete re-submission of monitoring plans rather than relying on supplements. Note that for installations emitting <25kt CO_2 pa, there is provision for simpler monitoring plan requirements.

Various changes have been made that could affect the relevance of presently permitted tiers, and there is a stronger emphasis on ensuring that the highest tier approach is complied with for major source streams in Category B and C installations (largest emitters) – note that this requirement does not apply to oxidation factor. Whilst tiers for liquid and gaseous fuels and solid fuels are still considered separately, a new category for 'commercial standard fuels' covering internationally standardised commercial fuels such as gas oil and propane has been introduced. For NCV, there is now allowance for lower tiers to use data from purchasing records for 'commercially traded fuels'. There is a strong preference stated for use of emission factors to be expressed as tCO_2/TJ, rather than tCO_2/t, although NCV values must still be reported in the latter case. The 'b'tiers (involving intermediate storage) for activity data have been deleted but the equivalent of the 'a' tiers remain in terms of specified maximum uncertainty, albeit with changes in text to include statements on fuel storage. The thresholds for minor and de-minimis source streams are doubled, but maximum tonnage caps have been introduced, whilst no-tier methods may now be applied in the case of pure biomass fuels.

There is a stronger emphasis on uncertainty assessment when using the calculation approach, in relation to evaluating compliance with the tier uncertainty thresholds – particularly for activity data. As noted above, there have been major changes to requirements on control and verification of emissions and a significant change is that the verifier is required to apply a materiality level of 5% for Category A and B installations and 2% for Category C installations.

In terms of sampling and analysis, use of accredited (EN ISO 17025:2005) laboratories is preferred, but non-accredited laboratories can now be used, albeit with certain criteria met on validation and inter-comparison. EN ISO 17025:2005 requirements in connection with use of on-line gas chromatographs are also confirmed. More guidance is provided on representative sampling and frequency of analysis which shall be designed to ensure that the annual average of the relevant parameter is determined with a maximum uncertainty of less than 1/3rd of the maximum uncertainty required by the approved tier level for the activity data for the same source stream. Where this is not achievable, minimum sampling frequencies are specified.

All definitions in this document are identical to those used in the EU Guidelines.

2. Calculation and measurement approaches

Annex IV of Directive 2003/87/EC permits a determination of emissions using either:

1. A calculation based methodology, determining emissions from source streams based on activity data obtained by means of measurement systems and additional parameters from laboratory analysis or standard factors.

2. A measurement based methodology, determining emissions from an emission source by means of continuous measurement of the concentration of the relevant greenhouse gas in the flue gas and the flue gas flow.

Note the use of new terminology, specifically:

Source Streams: specific fuel type, raw material or product giving rise to emissions of relevant greenhouse gases at one or more emission sources as a result of its consumption or production.
Measurement Systems: complete set of measurement instruments and other equipment, like sampling and data processing equipment used for the determination of variables like activity data, NCV etc.
Emission Source: separately identifiable part (point or process) of an installation from which relevant greenhouse gases are emitted.

The EU Guidelines express a clear preference to calculation-based methodologies and if measurement-based methods are used then the operator has to corroborate the measured emissions by means of a calculation-based methodology in any case. At UK Power Stations, it is not current practice to measure CO_2 emissions directly and Operators agree with the view that CO_2 mass emissions can be calculated from the coal burn more accurately than they can be measured.

In addition to the uncertainty relating to the concentration measurement, the determination of an accurate stack gas flow rate is fraught with difficulty. When considering large diameter Power Station stacks (typically, 8m diameter in the UK) it is not feasible to employ the devices traditionally used for gas flow rate measurement in pipes, e.g., orifice plates/Venturi meters for volumetric flow or Coriolis meters for mass flow. In-situ measurements can be made using averaging Pitots, thermal anemometer arrays or ultrasonic line-of-sight devices. However, unless the flow is very uniform and already well-characterized, in-situ calibration is required – usually a comparison with a Pitot tube velocity traverse. In addition, full calibration using '3D' Pitots may be difficult due to possible restricted access and the requirement to maintain constant load factors during calibration.

In addition, it is not always possible to measure emissions in the stack. For instance, when several units supply a shared stack, measurements are required in short sections of large duct work upstream of the stack in order to deliver the emissions data on a unitized basis.

In addition to the general difficulties in obtaining representative measurement locations on older installations, a more fundamental concern is the sensitivity of flow uniformity to installation load and operating characteristics. In these circumstances, the 'calibration' will only be valid when the installation is operated exactly as it was during the initial proving exercise.

The methodology proposed in this document uses the calculation approach and the following text therefore omits the measurement-based approach entirely. However, the industry will maintain a 'watching brief' on continuous measurement technology for greenhouse gases and will regularly review the potential for future use. Although the chosen approach is based on calculation, the calculations are based on activity data derived from measurement systems and additional laboratory analysis, as well as standard factors.

3. Overview of methodology and uncertainty tiers

3.1. Introduction

The fundamental component of the monitoring plan as required in the EU Guidelines is the identification of uncertainty tiers for the determination of activity data, net calorific values, emission factors and oxidation factors. The increasing numbering of tiers reflects increasing levels of accuracy, with the highest numbered tier as the preferred tier. Equivalent tiers are referred to with the same tier number and a specific alphabetic character (e.g.: Tier 2a and 2b).

For plant with emissions greater than 50kt fossil CO_2 pa (category B and C installations), the highest tier is required for monitoring and reporting purposes for all source streams, unless the highest tier approach is technically not feasible or will lead to unreasonably high costs. Justifications must be made (within the site specific monitoring plan) where the operator wishes to use a lower tier than that recommended in either this document or in the minimum tiers recommended in the EU Guidelines for the period 2008-2012. The use of tiers lower than the minimum tier specified in the EU Guidelines for major source streams can only be justified on the basis of technical infeasibility and not high costs. The requirement to use the highest tier no longer applies to oxidation factors.

The operator may apply different approved tiers to the activity data, emission factors, oxidation or conversion factors used within a single calculation. Stating the combination of tiers in the emissions report constitutes reporting uncertainty for the purposes of the Directive. However, the operator must now provide written proof of the uncertainty level associated with the activity data for each source stream to demonstrate compliance with the uncertainty thresholds defined for tiers in the EU Guidelines. This should be based on the specifications of the measurement instruments used, or for a measurement system the cumulative effect of uncertainties of its components estimated using the error propagation law. For 'commercially traded fuels', the Environment Agency/SEPA may permit annual activity to be determined from the amount of fuel or material invoiced without further proof of uncertainties, providing they are based on national or international standards that meet the uncertainty threshold of the permitted activity tier.

The EU Guidelines indicate a need to calculate, as accurately as practicable, major source streams and minor source streams. Minor source streams are those selected by the operator to jointly emit 5 kt of fossil CO_2 or less per year or to contribute less than 10% (up to a total of 100 kt of fossil CO_2 per year) to the total annual emissions of an installation, (whichever is the highest in terms of absolute emissions). Major source streams are those that do not qualify as minor source streams. A Power Station may apply lower tiers for the variables used to calculate emissions from minor source streams, than the tiers applied for the variables used to calculate emissions from major source streams within an installation. For minor source streams, the operator may select as a minimum the Tier 1 level.

Those minor source streams selected by the operator and jointly emitting 1 kt of fossil CO_2 or less per year or that contribute less than 2% (up to a total maximum contribution of 20 kt of fossil CO_2 per year) of total annual emissions of that installation, (whichever is the highest in terms of absolute emissions), are designated 'de-minimis' source streams and the Power Station may apply their own 'no-tier' estimation method.

In cases where it is technically not feasible or would incur unreasonable costs to apply at least Tier 1 for all source streams (except de-minimis), a 'fall back approach' may be agreed with the Environment Agency/SEPA. This is a fully customized alternative methodology proposed by the operator. It must be demonstrated that when applied to the whole plant that a specified uncertainty level for the plant is met. Since all power stations are using the tiered methodologies for major and minor source streams, and no-tier approaches are available for de-minimis streams, it seems unlikely that operators would need to use 'fall back approaches'. The EU Guidelines, Section 5.3 contain further details. Application of a fall back approach is regarded as a last resort.

For installations with low emissions, defined as less than 25kt fossil CO_2 per year during the previous trading period, the Environment Agency/SEPA may permit lower tier approaches with tier 1 as minimum for all source streams. Further simplifications of the reporting methodologies are discussed in Section 16 of the EU Guidelines.

The EU Guidelines have been revised for installations which may co-fire pure biomass fuels. A fuel qualifies as pure biomass if the non-biomass content is less than 3%. Where a fuel is purchased which contains a variable biomass content, then this must be addressed within the site monitoring plan. For pure biomass fuels, no-tier approaches may be applied for the activity data and calculation of the CO_2 emission arising from the fossil component of the biomass. For the uncontaminated biomass utilised in the power industry, it is assumed that the biomass content is 100%.

Hence, for the power sector, the scale of the operations means that there may be a considerable number of individual source streams and it is necessary for operators to identify these in the site monitoring plan as major, minor or de-minimis source streams so that the appropriate tier can be allocated.

If the highest tier methodology, or the variable-specific agreed tier, is temporarily not feasible for technical reasons then an operator applies the highest achievable tier until such time as the conditions for application of the former tier have been restored. The operator provides proof of the necessity for a change of tiers to the Environment Agency/SEPA and details of the interim monitoring plan. The operator takes all necessary action to allow the prompt restoration of the original tier for monitoring and reporting purposes.

Changes of tiers are fully documented both in the annual report and in the day-to-day data collection processes. The treatment of minor data gaps which result from downtimes of metering equipment (for example during breakdowns of weighbridges) follow good professional practice. When tiers are changed within a reporting period the results for the affected activity are calculated and reported as separate sections of the annual report to the Environment Agency/SEPA for the respective parts of the reporting period.

Fuel used for powering site transport or coal-moving equipment is not included in the calculation for CO_2.

3.2. Combustion emissions

CO_2 emissions from combustion sources are calculated by multiplying the energy content of each fuel used by an emission factor and an oxidation factor. For each fuel the following calculation is carried out for each activity:

CO_2 emissions = Activity data * Emission factor * Oxidation factor

All coal-fired installations, and most oil-fired installations, operate with stocking areas and/or storage tanks so that activity data are normally determined using a mass balance approach rather than the direct metering approach. The EU Guidelines no longer make a distinction between the mass balance approach and the direct metering approach in the allocation of tiers. It is sufficient to achieve the uncertainty level specified by the appropriate activity tier.

It should be noted that the EU Guidelines allow the Operator to define both fuel consumption and CO_2 emission factors based on either a unit energy or mass or volume consumed approach, as explained below, but the latter two need to be justified on the basis of unreasonable cost.

Activity data:

Activity data are expressed as the net energy content of the fuel consumed [TJ] during the reporting period. The energy content of the fuel consumption is calculated by means of the following formula:

Energy content of fuel consumption [TJ] = fuel consumed [t or Nm^3] * net calorific value of fuel [TJ/t or TJ/Nm^3]

However, as indicated in the EU Guidelines, the use of an emission factor for a fuel expressed as carbon content on a mass or volume basis (tCO_2/t or tCO_2/Nm^3) rather than an energy basis (tCO_2/TJ) for combustion emissions is restricted to cases where unreasonable cost would be otherwise be incurred. For stations where payment for fuel is calculated on a CV basis, the tCO_2/TJ option is more appropriate since it is in line with existing practices. For other stations, a tCO_2/t or tCO_2/Nm^3 fuel option may be preferred. This option is specifically recognised within the EU Guidelines (Section 5.5).

However, even where the calorific value of the fuel is not used for the calculation of CO_2 emissions, the operator is nevertheless required to periodically determine the energy content of the fuel to meet his reporting requirements as specified in Section 8 of the EU Guidelines.

Where activity data cannot be measured directly, a stock change approach is used. Fuel consumption is calculated using a mass balance approach based on the quantity of fuel purchased and the difference in the quantity held in stock over a period of time using the following formula:

Fuel C = Fuel P + (Fuel S – Fuel E) – Fuel O

where:

Fuel C: Fuel combusted during the reporting period
Fuel P: Fuel purchased during the reporting period
Fuel S: Fuel stock at the beginning of the reporting period
Fuel E: Fuel stock at the end of the reporting period
Fuel O: Fuel used for other purposes (transportation or re-sold)

The structure of the uncertainty tiers is as follows:-

Tier 1: The fuel consumption over the reporting period is determined by the operator or fuel supplier within a maximum uncertainty of less than ±7.5% taking into account the effect of stock changes where applicable.

Tier 2: The fuel consumption over the reporting period shall be determined by the operator or fuel supplier within a maximum uncertainty of less than ±5% taking into account the effect of stock changes where applicable.

Tier 3: The fuel consumption over the reporting period shall be determined by the operator or fuel supplier within a maximum uncertainty of less than ±2.5% taking into account the effect of stock changes where applicable.

Tier 4: The fuel consumption over the reporting period shall be determined by the operator or fuel supplier within a maximum uncertainty of less than ±1.5% taking into account the effect of stock changes where applicable.

It should be noted that different fuel types might result in different permissible uncertainties for the metering process with gaseous and liquid fuels generally being metered more accurately than solid fuels. There are however many exceptions within each of the classes (depending on the type and properties of the fuel, the delivery path (ship, rail, truck, conveyor belt, pipeline) and circumstances specific to the installation) which preclude a simple attribution of fuels to tiers.

For commercially traded fuel or material, the Environment Agency/SEPA may permit the determination of activity data based on the invoiced amount of fuel or material without further proof of uncertainties, provided that the demonstrated use of national or international standards ensures uncertainty thresholds are met. For low emission installations (<25 kt fossil CO_2 pa), the use of all fuel and materials can be determined from purchase records and stock change estimates without consideration of uncertainties.

Net calorific value:

Tier 1: The operator applies reference values for each fuel as specified in Section 11 of Annex 1 of the EU Guidelines.
Tier 2a: The operator applies country specific net calorific values for the respective fuel as reported in its latest national inventory submitted to the UNFCCC.
Tier 2b: For commercially traded fuels the net calorific values as derived from the purchasing records for the respective fuel provided by the fuel supplier are used, provided they have been derived based on accepted national or international standards.
Tier 3: The net calorific value representative for each batch of fuel in an installation is measured by the operator, a contracted laboratory or the fuel supplier in accordance with the provisions of Section 13, Annex 1 of the EU Guidelines.

Emission Factor:

Tier 1: Reference factors for each fuel are used as specified in Section 11 of Annex 1 of the EU Guidelines.
Tier 2a: The operator applies country specific emission factors for the respective fuel as reported in its latest national inventory submitted to the UNFCCC.
Tier 2b: The operator derives emission factors for each batch of fuel based on one of the following established proxies:

- density measurement of specific oils or gases common e.g. to the refinery or steel industry, and
- net calorific value for specific coals types,

in combination with an empirical correlation as determined at least once per year.

Tier 3: Activity specific emission factors representative for the respective batches are determined by the operator, an external laboratory or the fuel supplier in accordance with the provisions of Section 13, Annex 1 of the EU Guidelines.

Oxidation Factor:

When energy is consumed not all of the carbon in the fuel oxidises to CO_2 and un-oxidised carbon is taken into account in the oxidation factor that is expressed as a fraction. For some installations and fuels, the oxidation factor is taken into account in the emission factor and no separate oxidation factor is required.

Tier 1: An oxidation factor of 1.0 is used.
Tier 2: The operator applies country specific oxidation factors for the respective fuel as reported in its latest inventory submitted to UNFCCC.
Tier 3: For fuels, activity-specific factors are derived by the operator based on carbon contents of ashes, effluents and other wastes and by-products and other non-fully oxidised gaseous forms of carbon emitted in accordance with the provisions of Section 13, Annex 1 of the EU Guidelines.

4. Derivation of uncertainty tier- solid fuels

4.1. Overview

Application of fuel management and accountancy processes to the quantity and quality (including calorific value and carbon content) assessments of delivered fuel are used, together with other measured data, to establish the activity data and emission factors in respect of solid fuels (such as coal, biomass, petcoke, waste fuels) consumed for power generation. The diverse nature of the fuels and stocking arrangements will mean that the detailed processes will vary from site to site, and will be described in site specific procedures.

The uncertainty tier approach for liquid fuels burnt in coal fired stations is considered in Section 5.

4.2 Activity data

Direct gravimetric metering of solid fuel to the burners is not generally available on UK utility installations with sufficient uncertainty. However, for most coal-fired installations stockpiles are used for temporary and strategic storage of coal and other solid fuels.

Activity data are therefore generally derived from measurements of fuel purchases received at the site, measurements of any fuel sold or otherwise transferred off the site, and estimates of changes in the fuel held on stock at the start and end of the reporting periods. (Where direct gravimetric metering of fuel to the bunkers is sufficiently accurate, consumption weight can be determined from these measurements and changes in bunker stock levels)

Stock changes used to calculate consumption within the reporting period are determined either from annual stock surveys or calculation from the station heat accountancy system reconciled with regular stock surveys. (See 4.3)

The fuel weight used for emission calculations will be the one used for all relevant fuel calculations and it is anticipated that it will be the one identified for payment within the supply contract. In order to achieve this, the weight of solid fuels will normally be measured on receipt at the site. Where such weighing equipment cannot be used, the weight of fuel received may be based on measurements taken by the supplier, or on measurements taken at another point in the supply chain, as near to the site as is practicable. Similar considerations apply to off-site transfers.

Fuels will normally be weighed by one of the following methods: -

- Using weighing equipment (road, rail or belt-weigher) that has a current Certificate of Accuracy issued by competent bodies and a maintenance contract in place that provides inspections at prescribed intervals. Gross and tare weighings are made for road and rail deliveries.
- By draught survey (measurement of a sea-going vessel's displacement before and after loading or discharging).

Procedures are in place to ensure that delivery information is secure and back up information is maintained in a secure area away from the weighbridge. Each member of staff involved in the process has specific work instructions, is aware of their responsibilities, and is fully trained. Training records are maintained and procedures are in place to expedite repairs to weighing equipment and detail the methods of measurement used during repairs. All such procedures are documented (see Section 9)

Rail weighbridges on most UK Power stations are generally capable of weighing to better than ± 0.5% on a moving system (although static calibrations may provide superior uncertainties for calibration purposes). Similarly, most installations' road weighbridges are capable of uncertainties better than ±0.1%.

Draught survey accuracy is generally ± 0.5% for a well conducted survey on a large vessel (IIMS COP for draught surveys, 1998) although there may be site-specific variability around this figure. This is particularly true if the surveyor is restricted to carrying out a deadweight survey which requires that the weights of all measureable non-cargo elements are determined.

Although activity data for pure solid biomass fuels are not strictly necessary for calculation of CO_2 emissions, the weights of such fuels are generally measured to the same uncertainty as coal in order to maintain accurate heat accounts.

The accuracy of these devices is generally significantly less than the uncertainty level required for Tier 4. Engineering judgment suggests that this would lead to an overall uncertainty that is within this specified tier and hence, for these classes of installation a Tier 4 uncertainty level is feasible. Proof of the uncertainties in the activity data is required to demonstrate compliance with the tier adopted. The monitoring plan requires a calculation of the overall uncertainty in activity data based on the uncertainties in the station metering systems. Example calculations for coal fired plant based on typical operating parameters are given in Appendix 1.3-1.1.

The example calculations demonstrate that coal plant using annual stock surveys would achieve an activity uncertainty of 0.7% and comply with Tier 4 assuming:

i) Weighbridge specifications state tolerances to ± 0.5 % or better. (Uncertainty in tonnage delivered is affected by uncertainty of weighbridges)

ii) No more than 25 % of coal delivered to site will remain on stock rather than being combusted within the reporting period. (Uncertainty in tonnage consumed is affected by uncertainty in tonnage delivered and must be weighted to reflect the relative tonnages delivered and consumed e.g. a station has 4 Mt delivered but consumes only 3 Mt in the reporting period, an uncertainty of 0.5% in delivered tonnage equates to an uncertainty of 0.67% in coal consumed.)

iii) Stock levels will not be more than 25 % of coal consumption over the reporting period. (Uncertainty in tonnage consumed is affected by uncertainty in tonnage on stock and must be weighted to reflect the relative tonnages on stock and consumed, e.g. a station consumes 4 Mt and has a stock level of 1 Mt, an uncertainty of 2% in stock tonnage equates to an uncertainty of 0.5% in coal consumed.)

iv) Accurate volumetric and density survey data are available for 75 % of the stock tonnage; an adjustment to account for stock change between the date of survey and date of reporting will apply to less than 25 % of the stock tonnage. (Uncertainty in stock tonnage is dependent upon the uncertainty in volumetric and density surveys. Additional uncertainty applies if these surveys are not conducted on exactly the start/end date of the reporting period.)

For stations using heat accountancy to calculate stock changes the example calculations show the plant would achieve an activity uncertainty of 0.9% and comply with Tier 4 assuming:

i) Weighbridge specifications state tolerances to ± 0.5 % or better. (Uncertainty in tonnage delivered is affected by uncertainty of weighbridges)

ii) No more than 25 % of coal delivered to site will remain on stock rather than being combusted within the reporting period. (Uncertainty in tonnage consumed is affected by uncertainty in tonnage delivered and must be weighted to reflect the relative tonnages delivered and consumed e.g. a station has 4 Mt delivered but consumes only 3 Mt in the reporting period, an uncertainty of 0.5% in delivered tonnage equates to an uncertainty of 0.67% in coal consumed.)

iii) The uncertainty in the stock change calculated by the heat accountancy system is no more than 0.85 % of coal consumption over the reporting period (e.g. for a station that consumes 2 Mt coal, the stock change uncertainty would be no larger than ±0.017 Mt. This level of uncertainty is used in the example but other heat accountancy systems may have different levels of uncertainty)

The activity uncertainties quoted above are examples of what can be expected from plant operating within the typical values of the parameters listed. These parameter values are provided for illustrative purposes and are not meant to be prescriptive. Plant with different operating parameters (e.g. higher stock levels) will have different uncertainties. Uncertainties should be estimated from the actual plant data using the appropriate method in Appendix 1.3-1.1. The calculations may be performed using the JEP uncertainty calculator spreadsheet.

For small (<50kt CO_2 pa) coal fired installations, where accurate rail or road weighbridges may not exist, site specific justifications will be necessary to use a lower tier. These plants are required to meet at least Tier 1 for all source streams except de-minimis or pure biomass streams. For low emission installations (<25kt CO_2 pa), Tier 1 is the minimum level required, though activity data on fuel or materials may be determined from purchase records and stock change estimates without consideration of uncertainties.

At each site, the methods employed will be in accordance with company- or site-specific practice, will be described in local or company procedures and stated in the site-specific monitoring plan. A change from the application of one tier to one associated with a lower uncertainty would require Environment Agency /SEPA approval.

4.3. Fuel management and accountancy

Stock audit data may not correspond precisely to the reporting period and, if so, activity data and emission factors are determined using estimates which are adjusted as and when the actual stock data results become available. Opening and closing stock levels, in terms of both quantity and quality (including calorific value and carbon content), are recorded in the fuel stock accounts that are maintained by all installations. Stock levels recorded in the fuel stock accounts are fully consistent with data for measured fuel purchases, for any off-site sales or transfers, and with the fuel consumption.

Changes in fuel stocks are determined by volumetric surveys that are undertaken for each stockpile at least annually. Densities of solid fuel stockpiles are determined at a frequency of at least once every two years, generally annually. (For smaller stockpiles it is acceptable (for inter alia health and safety and/or practicality reasons) to apply estimates of density based on measurements taken on other representative stockpiles.) These periodic checks are reconciled against those recorded in the fuel stock accounts derived from the heat accountancy system. Where there are differences between the stocks shown in the accounts and physical measurements that are outside tolerance bands defined for each location, adjustments are applied to the accounts, and any adjustments necessary to activity data and emission factors made, either as retrospective adjustments to reported data, or brought forward into the current reporting period. Tolerance bands, details of processes employed to reconcile the accounts and physical measurements, and procedures for applying any necessary adjustments are defined in local procedures.

If weight and/or quality of fuel consumed are measured directly, the fuel stock accounting process reconciles these measurements with those made on receipt and with stock volumes and qualities, and any necessary adjustments applied appropriately. The uncertainty arising from fuel stockpile changes is considered in Appendix 1-3.1.3 and 1-3.1.4.

4.4. Net Calorific Value Data and Emission Factor data

Derivation of NCV and emission factors within the industry is generally carried out to the requirements laid down in Section 13[1], Annex 1 of the EU Guidelines.

Each fuel delivered to a Power Station has a specification analysis, agreed with the supplier. Normally, for fuel from UK sources, the fuel supply contract states quality criteria to be met for all deliveries, and the supplier endeavours to see that these criteria are met through routine analyses of fuel samples at the point of dispatch (e.g. coal mine). For sea-borne deliveries, the standard loadport analysis may act as the fuel specification.

Deliveries of solid fuel to Power Stations are sampled on arrival by means of an automatic or manual sampling system to ISO13909. Note that the mechanical sampling aspects of BS 1017-1:1989 (coal) and BS 1017-2:1994 (coke) have been superseded by BS ISO 13909 parts 1 to 8, the relevant parts (coal) of which are detailed below.

Part 1	General Introduction	BS ISO 13909-1:2001
Part 2	Coal – Sampling from Moving Streams	BS ISO 13909-2:2001
Part 3	Coal – Sampling from Stationary Lots	BS ISO 13909-3:2001
Part 4	Coal – Preparation of Test Samples	BS ISO 13909-4:2001
Part 7	Methods for Determining the Precision of Sampling, Sample Preparation and Testing	BS ISO 13909-7:2001
Part 8	Methods for Testing of Bias	BS ISO 13909-8:2001

The manual sampling aspects of BS 1017-1:1989 (coal) and BS 1017-2:1994 (coke) have been superseded by BS ISO 18283:2006 Hard Coal and Coke Manual Sampling. Automatic sampling is covered by ISO 13909:2001. As from January 1st 2008, BS 1017 will be invalid and operators will have to use the ISO 13909 and ISO 18283 equivalents.

Sampling procedures, as stated in ISO18283 or ISO13909, are designed to ensure that the sample taken is statistically representative of the delivery. Automatic sampling systems installed at the Power Station are regularly inspected (typically on a monthly or quarterly basis) to BS ISO 13909-7 and 8:2001 by third party assessment to ensure that the equipment is operating satisfactorily and the collected samples are of high integrity. These inspections include tests on the sampling systems, typically on an annual or two yearly basis, to show that no significant bias is present when the coal sample is taken from the delivery. Only operatives who have

[1] In the UK power industry, analysis is undertaken by accredited laboratories. Section 13 indicates a preference that laboratories performing analyses are accredited to EN ISO 17025, but also defines validation and inter-comparison procedures for non-accredited laboratories.

received training and have been assessed in the methods and techniques of coal sampling will have any involvement with coal sampling activities.

It may be impractical to sample every delivery to a station, due to the frequency at which deliveries arrive at the station and a restriction on the rate at which coal can be processed through the sampler. In such instances, sampling is targeted preferentially at those fuel sources where few deliveries have already been sampled.

The EU Guidelines require that the sampling procedure and frequency of analysis is designed to ensure that the annual average of the relevant parameter is determined with a maximum uncertainty of $1/3^{rd}$ of the maximum uncertainty required by the approved tier level for the activity data for the same source stream. For Tier 4 activity level, this would mean an uncertainty of less than ±0.5% in the determination of the NCV and emission factor. Where this is not achievable, it is sufficient to sample at least every 20000 tonnes or 6 times a year (which ever is the greatest). **Appendix 1-3.2.1 considers the frequency of sampling required to achieve this level of uncertainty. For example, for a coal station continuously firing at least 6 coals (of different sources of origin), 12 composite samples of each coal per year will achieve the uncertainty requirement for the emission factor. In reality, coal from a given source of origin may be fired for only part of the year and the total number of coals fired could be much higher. However, in all cases, it is anticipated that a sufficient number of samples can be taken for every separate source of origin. For NCV determination 52 samples per year would be compliant.**

Deliveries of solid biomass fuels (or biomass blends) to a Power Station are also sampled with the most appropriate sampling techniques, as described in the site-specific monitoring plan. For solid waste (pure fossil or mixed biomass fossil) the requirement is to sample every 5000 tonnes or at least 4 times a year (which ever is the greatest).

Sampling of stockpiles is conducted at prescribed intervals to validate fuel stock quality records. During the survey, a number of samples are taken across each stockpile (in a grid pattern) for analysis.

4.5. Sample Preparation and Analysis

Sample preparation within the industry is carried out to the requirements laid down in Section 13 of the EU Guidelines.

Solid fuel samples require preparation to convert the raw coal sample collected to a sample suitable for analysis. All sample preparation equipment is routinely inspected to ensure that equipment and processes are operating satisfactorily. In addition, the laboratories undertake testing schemes to ensure that processes are free of bias and the analysis samples are representative of the raw samples collected.

Routinely, all solid fuel samples are analysed in accordance with BS1016 for total moisture (% as received), ash content (% as received), volatile matter content (% as received), sulphur content (% as received) and gross calorific value (GCV, kJ/kg as received). From this information, defined calculations (known as Parr calculations) are used to determine hydrogen content (% as received) and net calorific value (NCV, kJ/kg as received). The BS standard BS 1016 and its ISO and ASTM equivalents are given below.

British Standard		ISO Standard	ASTM Standard
1016-1:1973	Determination of total moisture content of coal	589:2003	
1016-104.1:1999	Determination of moisture content of general analysis sample of coal	11722:1999	
1016-104.4:1998	Proximate analysis - determination of ash content	1171:1997	
1016-104.3:1998	Proximate analysis - determination of volatile matter content	562:1998	
1016-105:1992	Determination of gross calorific value	ISO 1928: 1995	
	Determination of sulphur content by high temperature combustion and IR		D 4239-02
	Determination of chlorine and sulphur by XRF (Asoma)		
	Determination of chlorine in coal by bomb combustion and ISE		D 4208-02
1016-6:1977	Determination of carbon, hydrogen and nitrogen		
	Standard Test methods for Instrumental Determination of C, H, N in Laboratory Samples of coal and coke	DD ISO/TS 12902 (2002)	D5373-02 (2007)

In a similar way to which hydrogen and NCV of coal are calculated, it is also possible to accurately calculate carbon in coal from its proximate analysis. Following work by the JEP comparing large datasets where the carbon content has been both measured and calculated, the Environment Agency/SEPA have accepted that either measurement or calculation of carbon is appropriate for EU ETS and therefore either option is available for the operator to select (Appendix 2).

For CO_2 reporting purposes, tonnage-weighted analysis data (i.e. moisture, as received carbon and NCV) will be calculated for each fuel source, based upon the tonnage and the analysis results for the fuel during the reporting period. Payment for the fuel (and therefore the calculation of CO_2) is generally done by reference to the energy content of each delivery.

Biomass is considered as CO_2-neutral and an emission factor of 0 is applied. The amount of biomass combusted (TJ) is reported as a memo item. However, CO_2 arising from biomass combustion is not reported unless total CO_2 emissions are measured using CEMs which would not be the case in the power industry. For pure biomass (defined in Section 3) a no-tier approach may be used. CO_2 emissions arising from any trace amounts of fossil carbon in the biomass shall be reported. Measurements of heat and CO_2 production are determined as coal and similar records maintained.

For all sizes of coal fired installation the uncertainty of the NCV data corresponds to the highest tier (Tier 3), since the net calorific value representative for each batch of fuel in an installation is generally measured by the operator, a contracted laboratory or the fuel supplier to the requirements laid down in Section 13[1] , Annex 1 of the EU Guidelines

The emission factor (E) is generally calculated for each delivery (or the aggregated sum of contracted deliveries) of fuel from the equation

E = (fraction carbon in fuel *3.664)/CV of fuel

For all sizes of coal fired installation the determination of the Emission factor corresponds to the highest tier (Tier 3), since activity specific emission factors representative for the respective batches are determined by the operator, an external laboratory or the fuel supplier to the requirements laid down in Section 13[1] of the EU Guidelines.

4.6. Oxidation factor

The combustion inefficiency relating to the residual carbon in ash is the only significant consideration when calculating the Oxidation Factor. The EU guidelines have waived the requirement to use the highest tier.

Where Tier 3 is used, the Oxidation factor (O) is calculated from the equation:

$$O = 1 - (C_{PFA} * W_{PFA} + C_{FBA} * W_{FBA}) / (W_{TOT} * C_{FUEL})$$

where

- C_{PFA} is the percentage of carbon in the PFA
- C_{FBA} is the percentage of carbon in the FBA
- W_{PFA} is the weight of PFA produced in the year
- W_{FBA} is the weight of FBA produced in the year
- W_{TOT} is the weight of fuel consumed in the year
- C_{FUEL} is the percentage of carbon in the fuel

This requires individual stations to be able to measure, (generally from the average weekly analyses of the ash sold or sent to landfill) the carbon content of the ash. This information is normally required to be produced as part of the stations routine Quality Assurance Programme for PFA and FBA customers using best practice analyses techniques.

Not all stations determine C_{FBA} and in these cases, this parameter is set to zero.

Sites can calculate the total volume of ash produced from the coal composition and throughput data. Volumes of PFA and FBA sold or sent to landfill are generally measured, but where for individual stations where the PFA/FBA ratio is not readily available, an 80/20 PFA/FBA default ratio may be assumed.

The EU Guidelines require that the sampling procedure and frequency of analysis is designed to ensure that the annual average of the relevant parameter is determined with a maximum uncertainty of 1/3rd of the maximum uncertainty required by the approved tier level for the activity data for the same source stream. For Tier 4 activity level, this would mean an uncertainty of less than ±0.5% in the determination of the Oxidation Factor. Appendix 1-3.3 considers the frequency of sampling required to achieve this level of uncertainty. This shows that 12 monthly composite samples of PFA and FBA will comply with the uncertainty requirement.

The EU Guidelines do not require the use of the highest tier for oxidation factors. Tier 1 uses an oxidation factor of 1, while Tier 2 corresponds to the use of a country specific oxidation factor as reported in the latest National Inventory submitted to the UNFCCC. The latest submission (2006) uses a value of 0.98 for power station coal, though, definitive values will be released by DEFRA annually. There is no requirement to assess uncertainty for Tier 1 and 2 oxidation factors.

4.7. Summary

The following table shows the tiers that can be achieved for coal fired installations, when operating to the standards described above. In all cases, the achievable tier is equal to or higher than the minimum required. Justification for the choice of tiers is given above.

Table 1. Comparison of achievable uncertainty tiers with tiers Listed in the EU Guidelines for solid-fuelled installations.

SOURCE	kt CO_2/year	>500	50-500	<50*
Activity data	Required	3	2	1
	Achievable	4	4	4
Calorific Value	Required	3	3	2a/2b
	Achievable	3	3	3
Emission	Required	3	3	2a/2b
	Achievable	3	3	3
Oxidation	Required	1	1	1
	Achievable	2/3	2/3	2

* Low Emission Plant <25 kt /year may use Tier 1 as a minimum subject to agreement with Environment Agency/SEPA.

5. Derivation of uncertainty tier- liquid fuels

5.1. Derivation of activity data

The techniques used at oil stations for determining activity data are also used at coal stations for measuring consumption of the fuel oil used for start-up and combustion support and for open cycle gas turbines burning gas oil.

At most stations, the total consumption of liquid fuels is based on receipts and measurements of stocks in tanks at the start and end of each period. The weight of liquid fuels delivered will normally be measured on receipt at the site. Where such weighing equipment cannot be used, the weight of fuel received may be based on measurements taken by the supplier, (by acceptance of custom and excise determined volumes and weights.) or on measurements taken at another point in the supply chain, as near to the site as is practicable. Similar considerations apply to off-site transfers.

It is anticipated that the fuel supply data used for payment within the supply contract is generally the one used for all relevant CO_2 calculations

The weight of liquid fuels delivered will normally be derived by one of the following methods: -

- Using weighing equipment that has a current Certificate of Accuracy issued by Trading Standards and a maintenance contract in place that provides inspections at prescribed intervals. Gross and tare weighings are made for road and rail deliveries. Large oil-fired stations, or large coal fired stations using significant quantities of oil for light up and/or combustion support will import their fuels over rail or road weighbridges that generally have an accuracy of <±0.5%. **The accuracy of these devices is generally significantly less than the uncertainty level required for Tier 4. Engineering judgment suggests that this would lead to an overall uncertainty that is within this specified tier and hence, for these classes of installation a Tier 4 uncertainty level is feasible. Proof of the**

uncertainties in the activity data is required to demonstrate compliance with the tier adopted.

- By discharging into off line tank(s) and measuring levels before and after receipt. This process generally has accuracy, over a whole year, of ± 1%. **The accuracy of these devices is generally significantly less than the uncertainty level required for Tier 4. Engineering judgment suggests that this would lead to an overall uncertainty that is within this specified tier and hence, for these classes of installation a Tier 4 uncertainty level is feasible. Proof of the uncertainties in the activity data is required to demonstrate compliance with the tier adopted.**

- By draught survey. This process generally has an accuracy of <± 0.5%. **The accuracy of these devices is generally significantly less than the uncertainty level required for Tier 4. Engineering judgment suggests that this would lead to an overall uncertainty that is within this specified tier and hence, for these classes of installation a Tier 4 uncertainty level is feasible. Proof of the uncertainties in the activity data is required to demonstrate compliance with the tier adopted.**

There are no fuel oil-fired generating installations in current use with emissions above 500kt fossil CO_2 per year. For those installations in the 50 – 500kt fossil CO_2 per year range Tier 3 may be appropriate because of their low load factors, the small stocks held for commercial reasons and the fact that deliveries sometimes coincide with fuel draw-off for combustion.

The monitoring plan requires a calculation of the overall uncertainty in activity data based on the uncertainties in the station metering systems. An example calculation for an oil fired station using tank level measurement is given in Appendix 1-4.1.1. Oil station operation and metering arrangements differ between stations so a generic calculation is not feasible, however the example will assist operators to make their own estimates.

Some stations use continuous flow metering to measure consumption. Depending on the type of flow meter used, the uncertainty in consumption would be 0.3 -1.5%. **A list of flow meters is given in Appendix A-4.1.2 together with assigned uncertainty levels. Provided that the meter is operated in accordance with the requirements listed in Appendix, a more detailed uncertainty analysis is not required, although evidence of calibration and associated tolerances must be provided by the Operator. All of the techniques listed comply with Tier 4.**

Similar considerations apply to installations releasing less than 50kt fossil CO_2 per year. It is proposed that tier 2 is employed rather than the highest tier, which would lead to unreasonable costs. For low emission installations (<25kt CO_2 pa), Tier 1 is the minimum level required, though activity data on fuel or materials can be determined from purchase records and stock change estimates without consideration of uncertainties.

Proof of the uncertainties in the activity data is required to demonstrate compliance with the tier adopted.

Biomass is considered as CO_2-neutral and an emission factor of 0 is applied. The amount of biomass combusted (TJ) is reported as a memo item. However, CO_2 arising from biomass combustion is not reported unless total CO_2 emissions are measured using CEMs which would not be the case in the power industry. For pure biomass (defined in Section 3) a no-tier approach may be used. CO_2 emissions arising from any trace amounts of fossil carbon in the biomass should be reported. However, for uncontaminated biomass fuels used by the power industry, the biomass content is assumed to be 100%. The weights of any such fuels are generally measured to the same uncertainty as any other liquid fuel on a station in order to maintain accurate heat accounts.

At each site, the methods employed will be described in local or company procedures. All such procedures are documented (see Section 9).

5.2. Calorific Value and Emission Factor
All deliveries of liquid fuels to Power Stations are sampled and analysed in accordance with BS 2000 part 61 or equivalents, ensuring that the analysis is statistically representative. Analysis may be by the supplier or the operator in which case a composite sample (e.g. on a weekly basis) is made to ensure a representative sample. Analysis standards are listed below.

	ASTM Standard
Standard test method for heat of combustion of liquid hydrocarbon fuels by bomb calorimeter	D240-02
Standard test methods for instrumental determination of C, H, N in petroleum products and lubricants	D5291-02

Storage tanks are fitted with sampling points to allow regular sampling of the stored oil for heat accounting purposes. The EU Guidelines require that the sampling procedure and frequency of analysis is designed to ensure that the annual average of the relevant parameter is determined with a maximum uncertainty of $1/3^{rd}$ of the maximum uncertainty required by the approved tier level for the activity data for the same source stream. For Tier 4 activity level, this would mean an uncertainty of less than ±0.5% in the determination of the NCV and emission factor. (For Tier 3 this becomes 0.83%). Where this is not achievable, the EU Guidelines suggest an indicative minimum sampling of at least every 20000 tonnes or 6 times a year (whichever is the greatest). Oil plants tend to sample on delivery but may have very low load factors so there may be less than six deliveries per year. **Appendix 1-4.4 considers the frequency of sampling required to achieve the required uncertainty. For NCV, only 1 sample per year is required for Tier 4, hence to comply with the uncertainty requirement, every delivery shall be sampled. Routine analysis will include GCV (kJ/kg as received). NCV is calculated using the Parr formulae. For carbon content at least 5 samples per year are required to comply with Tier 4, hence it may be necessary to analyse more than one sample from each delivery.** The Tier 3 uncertainty requirement would be achieved by 2 samples, hence it would be sufficient to sample every delivery.

The EU Guidelines now include a new fuel category, ‘commercial standard fuels’. These refer to fuels which exhibit a 95 percent confidence interval of less than 1% on their NCV. Such fuels include gas oil, light fuel oil and propane. For these fuels the minimum permitted tier for NCV and emission factor is reduced from 3 to 2a/2b. (See footnote in Table 2). For ESI plant these fuels are likely to be minor or de-minimis source streams, though gas oil is used in OCGTs.

For each of the power installations covered by this guidance, Tier 3 uncertainty is generally achieved, i.e. the net calorific value representative for each batch

of fuel is measured by the operator, a contracted laboratory or the fuel supplier to the requirements laid down in Section 13[1] of the EU Guidelines.

The emission factor (E) is generally calculated for each delivery (or the aggregated sum of contracted deliveries) of fuel from the equation

E = (fraction carbon in fuel * 3.664)/CV of fuel

Received carbon content is generally measured, by fuel analysis, in accordance with Tier 3 requirements. Where this is not considered practical (i.e. for the medium or smaller oil-fired installations), Tier 2b uncertainty levels will be used and NCV based upon the DAF carbon content of the oil, which is approximately constant for a given fuel source.

5.3 Oxidation Factor

It is not normal practice to determine the unburnt carbon content of fuel oil ash so Tier 3 is not readily available. However, the EU Guidelines do not require the use of the highest tier for oxidation factors. Tier 2 corresponds to the use of a country specific oxidation factor as reported in the latest national inventory submitted to the UNFCCC. The latest submission (2006) uses a value of 1.0 for liquid fuels which also corresponds to the Tier 1 default value. The definitive values will be released by DEFRA annually. There is no requirement to assess uncertainty for Tier 2 oxidation factors.

5.4 Summary

Table 2 shows the tiers that can be achieved for installations using liquid fuels as their principal fuel, when operating to the standards described above. In all cases, the achievable tier is equal to or higher than the minimum required in the EU Guidelines

Table 2. Comparison of achievable uncertainty tiers with tiers listed in the EU Guidelines for liquid-fuelled installations.

SOURCE	kt CO_2/year	>500	50-500	<50
Activity data	Required	4	3	2
	Achievable	4	4	3
Calorific Value	Required	3*	2a/2b	2a/2b
	Achievable	3	3	3
Emission	Required	3*	2a/2b	2a/2b
	Achievable	3	2b	2b
Oxidation	Required	1	1	1
	Achievable	2	2	2

* For commercial standard fuels the required tier is 2a/2b

6. Derivation of uncertainty tier- gaseous fuels

6.1. Activity data

Natural gas is regarded as a commercially traded fuel with regard to the EU Guidelines. The Environment Agency/SEPA may permit the determination of annual activity data based on supplier's invoices without further proof of uncertainties, provided national legislation or relevant national or international standards ensure that the uncertainty requirements for the respective activity tiers are met. The following sections and Appendix 1 demonstrate the uncertainties in metering natural gas under the current legislation and standards and can be used to justify the activity tier if required.

The volume of gas consumed, expressed as normal or standard cubic metres, and at each site is measured by fiscal standard metering, either owned by the site or by the supplier. These devices are normally of a positive displacement type and are compensated for pressure and temperature at the metering location.

In some cases, notably at cogeneration sites, the gas delivered may be split downstream of the metering to supply two or more processes. Supplies to each process are then determined using local metering, in accordance with local procedures for each site.

The volume flow is corrected to metric 'standard' reference conditions as used in the gas industry (15.0°C and 1.01325 bar absolute pressure) (IGE/GM/1). Metering types include orifice plates, turbine meters, ultrasonic devices and positive displacement meters.

For the largest (Category C) installations, e.g., CCGT installations, the level of flow measurement uncertainty is agreed between the supplier and the user but is normally based on DTI guidelines for custody transfers within the petroleum industry (DTI, 2003). **These guidelines specify that mass flow measurement should be within an overall uncertainty of ±1%, thus satisfying the Tier 4 requirement of ±1.5%.**

Ensuring this level of metering quality, on an ongoing basis, is dependent on good installation and maintenance practice, as defined in COP1c, 1996.

Flow metering for smaller installations within the Electricity Supply Industry is covered by IGE/GM/4, 1996. This standard is mandatory for meters covered by COP1c, with a capacity greater than 1076 m^3/h, equivalent to a installations thermal input of about 10MW gross (about 20 kt CO_2/annum). This standard states that an uncertainty of ±1% 'can be achieved'.

This satisfies the Tier 4 requirement of ±1.5% and is better than the minimum Tier 3 and Tier 2 requirements for intermediate and small (Categories B and A respectively) installations given in the EU Guidelines.

Further codes of practice for smaller installations (COP1a, COP1b and IGE/GM/1) are not considered further since these are not expected to be relevant to power generation installations with a capacity greater than 10MW gross thermal input.

The monitoring plan requires a calculation of the overall uncertainty in activity data based on the uncertainties in the gas metering systems. Appendix 1-5.1 considers the uncertainties in a range of gas metering devices under specified operating conditions and shows them to achieve an uncertainty of 1.1% which is within the Tier 4 criterion. These estimates can be referenced by any gas fired station in their Monitoring & Reporting Plans provided that the flow metering installations used for EU ETS reporting are compliant with the specified flow metering and calibration standards, or the Competent Authority Guidance (as appropriate), and the relevant gas analysis calibration standards (as appropriate). Evidence of calibration and associated tolerances must be provided by the Operator.

6.2. Net Calorific Value and Emission factor

Large installations

The quality of natural gas fired at Power Stations is usually based on continuous automatic analysis of the gas stream. For large consumers this is undertaken locally to the installations, either by the gas supplier or by the consumer. In other cases analysis is undertaken by the supplier at a representative location on the supply network. Where the analysis is by the supplier manual samples can be taken and sent offsite for remote analysis as a check of the automatic analysis. Sampling of high-pressure natural gas requires specialist equipment and competent personnel and is therefore only conducted by external contractors and suppliers. Guidelines for sampling natural gas are provided in BS EN ISO 10715 (2001). Each of these options is equivalent in uncertainty and the site-specific monitoring plan identifies the actual option adopted.

Under normal circumstances, the chosen frequency of sampling and analysis will easily satisfy the uncertainty requirements. However, if the operator is not able to meet the allowed uncertainty for the annual average carbon content or NCV (one third of the Tier uncertainty for the Activity Data), at least a weekly analysis is required. Appendix A1-5.2.1 considers the uncertainties in the calculation of emission factors and NCV from gas chromatograph data and shows them to be within the uncertainty criterion for Tier 4. The requirement to achieve the allowed uncertainty still applies even if the NCV is not used in the calculation of CO_2 emissions, for example if activity is measured in m^3 and emission factor in $tC\ m^{-3}$.

The operators of on-line fuel gas analysers and gas chromatographs must meet the requirements of EN ISO 9001:2000. On-line systems require an initial validation and an annual check to be performed either according to EN ISO 10723:1995 or the procedures laid down in the EU Guidelines. Calibration services, sampling and analysis of grab samples and the suppliers of calibration gases must be accredited to EN ISO 17025:2005.

Natural gas analysis, when conducted on site, gives the component gas concentrations with the heat content being calculated from the composition as described in ISO 6976: 1995. Average NCV in any period can then be calculated from the individual NCVs for each batch analysis (Tier 3). Average as received carbon values can be in any period can be calculated from the average compositional data (Tier 3). These values can then be used for determining the emission factor. When it is not cost effective to measure the gas composition directly, the fuel supplier may be able to provide an appropriate analysis from the nearest measurement point on the distribution grid.

In the UK, the gross CV is reported in MJ/m^3, specified at the same metric standard reference conditions defined for flow metering (15.0°C, 101.23 kPa).

For reporting purposes, the net CV is preferably calculated from the gas composition, in accordance with ISO 6976:1995. Alternatively, a fixed conversion factor of 0.90, suggested by the IPCC (2006) can be applied, noting that the factors for methane and a typical UK natural gas are 0.901 and 0.905, respectively (within 0.5% of the IPCC factor).

Note that an energy based emission factor can be used directly with the billed energy consumption (gross) without reference to the CV but the net energy content must, in any case, be reported.

For the largest installations, e.g., CCGT installations, the level of uncertainty for energy flow is based on DTI guidelines (DTI, 2003). **The quoted value of ±1.1%, when combined with the flow uncertainty, implies that the uncertainty of CV measurement is of the order of ±0.3% and satisfies the Tier 3 requirement that the CV is measured.**

Intermediate installations
Natural gas calorific value is reported by the supplier across the relevant billing period (Tier 2b). This calorific value is normally calculated from the natural gas composition, which is measured to a high quality by means of gas chromatography as described above (BS EN ISO 6974, 2001). The billed energy use is thus determined from the supplier's meter and gas quality device, which is operating to the standards described below.

Emission factor is specified by a Tier 2a approach in which the operator applies the carbon content reported by the UK in its latest National Inventory submitted to the Secretariat of the United Nations Framework Convention on Climate Change. This is updated annually on the DEFRA web site by region as determined by Post Code (see References).

Small installations
It is not generally cost effective to install and maintain high quality gas chromatographs on installations that are not large enough to have a guaranteed quality of supply from the fuel provider and **so a Tier 2b approach is applicable for the NCV, as described above, or a Tier 2a approach** in which the operator applies the NCV reported by the UK in its latest National Inventory submitted to the Secretariat of the United Nations Framework Convention on Climate Change. This is updated annually on the DEFRA web site by region as determined by Post Code (see References).

6.4 Oxidation Factor
For installations operating exclusively or principally with gaseous fuels, the Tier 1 Oxidation Factor (minimum requirement) recommends a standard, default, oxidation factor of 1.0. Tier 2 specifies that the operator applies the oxidation factor reported by the UK in its latest National Inventory submitted to the Secretariat of the United Nations Framework Convention on Climate Change. **The latest submission (2006) uses a value of 1.0 for gaseous fuels which also corresponds to the Tier 1 default value. The definitive values will be released by DEFRA annually. There is no requirement to assess uncertainty for Tier 2 oxidation factors.**

6.5. Summary
Table 5 shows the tiers that can be achieved for natural gas fired installations, (or for coal fired installations with gas co-firing) when operating to the standards described above. In all cases, the achievable tier is equal to or higher than the minimum required. Justification for the choice of tiers is given above.

Table 3. Comparison of achievable uncertainty tiers with listed in the EU Guidelines for gaseous-fuelled installations

SOURCE	kt CO_2/year	>500	50-500	<50
Activity data	Required	4	3	2
	Achievable	4	4	4
Calorific Value	Required	3	2 a/b	2 a/b
	Achievable	3	2 a*/b	2 a*b
Emission	Required	3	2 a/b	2 a/b
	Achievable	3	2a	2a
Oxidation	Required	1	1	1
	Achievable	2	2	2

* based on the geographical average CV reported by the fuel supplier

7. Derivation of Activity and Emission factor data - FGD processes

7.1. Overview

The EU Guidelines indicate that FGD CO_2 emissions from the use of limestone for SO_2 scrubbing should be calculated on the basis of limestone purchased or gypsum produced. These two calculation methods are equivalent and are designated as Tier 1. Tier 1 is the only tier available.

Site-specific methodologies are required for alternative FGD systems such as dry scrubbing.

The calculation is as follows:
CO_2-emissions [t] = Activity data * emission factor

Note that unlike the Phase 1 EU Guidelines, allowance for a conversion factor (accounting for any unreacted limestone) is not included in the current EU Guidelines.

7.2. Activity data

The EU Guidelines indicate for FGD plant a Tier 1 uncertainty level is appropriate. Activity data are determined by measuring the tonnes of dry limestone or gypsum as process input/output per year metered by operator or supplier with a maximum permissible uncertainty of less than ±7.5% for the overall process. The relevant activity factor is calculated from the sum of the weights of limestone delivered/gypsum supplied corrected for the measured moisture contents.

Limestone is weighed at the quarry and/or on delivery at the Power Station. Limestone is delivered by rail, and so will always pass over calibrated rail weighbridges (for both gross and tare weights) which may also be used for weighing coal and other solid fuels. Gypsum is exported via either rail or road weighbridges. Rail weighbridges on most UK Power stations are generally capable of weighing to better than ± 0.5 % on a moving system (See Appendix 1-3.1.1) with road weighbridges weighing to around 0.1 % so that both approaches amply satisfy the Tier 1 requirements. The only activity Tier specified for process emissions in Annex II Section 2.1.2. is Tier 1.

7.3. Emission factor

Within the FGD plant calcium carbonate (limestone) is converted into calcium sulphate (gypsum) releasing CO_2.

Each limestone delivery to the Power Station will have a specification analysis provided by the supplier. The limestone supply contract between the Power Station and the supplier states quality criteria that must be met. The Power Stations do not perform any independent analysis of the limestone, on individual deliveries but rely on the suppliers quality controlled data. The analysis is performed to BS 6463 part 102; *Quicklime, Hydrated Lime and natural calcium limestone, Methods for chemical analysis.* The Tier 1 requirement is that the calcium carbonate and magnesium carbonate of the limestone is determined using best industry practice.

For Tier 1, EU Guidelines indicate that the emission factor is determined by using the factor of 0.44 (for the ratio of t CO_2/t dry limestone) multiplied by the fraction of $CaCO_3$ in the dry limestone feedstock.

i.e. Emission Factor = Limestone Purity % / 100 x 0.44

A similar approach is adopted when gypsum production is used to determine CO_2 emissions from FGD. In this instance, gypsum is stored on site and is stock checked every week to measure volumes. The Power Station analyses the gypsum, to methods agreed with the customer, for moisture and purity. These methods are taken from *"Standard Methods for Chemical Analysis of Gypsum and Gypsum Products" (2001), ASTM Designation C477M-01*. Samples are tested in-house with two different heating tests and measuring the loss of weight to give moisture and purity %.

The emission factor is determined by using the factor of 0.2558 (for the ratio of t CO_2 / t dry gypsum ($CaSO_4.2H_2O$)) multiplied by the fraction of $CaSO_4.2H_2O$ in the dry gypsum product.

i.e. Emission Factor = Gypsum Purity % / 100 x 0.2558

7.4. Conversion factor

As noted above, allowance for a conversion factor accounting for unreacted limestone is omitted from the current EU Guidelines and therefore 100% conversion of limestone must be assumed.

7.5. Summary

Table 4. Achievable uncertainty tiers for FGD plant

Activity data	Required	1
	Achievable	1
Emission	Required	1
	Achievable	1

8. Tier Selection Summary

Operators are required to use the highest tier for all plant with emissions greater than 50kt fossil CO_2 pa (categories B and C). This would include most power stations. If it can be demonstrated to the Environment Agency/SEPA that the highest tier is technically not feasible or will lead to unreasonably high costs, the next lower tier may be used. For oxidation factors only, the requirement to use the highest tiers is waived in the EU Guidelines. The recommended tiers of uncertainty within the power-generating sector for the principal fuel source are indicated in tables 5-7 below.

In all cases, the opportunity exists for operators to use a lower approach for ‘minor’ source streams down to a minimum of Tier 1 after justification to Environment Agency/SEPA. For ‘de-minimis’ source streams a ‘no tier’ approach may be used. Liquid fuels are frequently used on coal and gas installations for combustion support, light up or for security of supply issues. Where liquid fuels support coal stations, the uncertainty tier will probably be determined by that for the major source stream since the same infrastructure and procedures are generally used. However, for some stations (for example those without weighbridges), alternative tiers may be utilised and a lower, or even a ‘no-tier’, approach may be acceptable if justified within the site-specific monitoring plan.

The principle adopted here is that the same techniques and management systems are used for fuel activity data, NCV, emission factor and oxidation factor whether the source is a ‘major’ (>90% of total emissions) or a minor (<10% of total emissions) one, unless the site monitoring plan indicates otherwise.

Table 5. Recommended tiers of uncertainty for a coal fired station with FGD (with and without gas co-firing).

CO_2 source	Fuel and material type	Uncertainty Tier For Activity Data	Uncertainty Tier For NCV	Uncertainty Tier for Emission Factor	Uncertainty Tier for Oxidation Factor
Generating Units Principal fuels and major fuel source streams >10% of total. Assuming fuel weights measured by weighbridges	Coal Gas (co-firing) Liquid fuels	4 4 4	3 3 3	3 3 3	2/3 2 2
FGD	Limestone	1	1	1	N/A

Table 6 Recommended tiers of uncertainty for an oil-fired station

CO_2 source	Fuel and material type	Uncertainty Tier For Activity Data	Uncertainty Tier For NCV	Uncertainty Tier for Emission Factor	Uncertainty Tier for Oxidation Factor
Generating Units Principal fuels and major fuel source streams >10% of total **	Liquid fuels	4*	3	3***	2

*Tier 3 may be applied for <500kt CO_2 pa installations
** Assuming fuel weights measured by weighbridges or by draught survey
***Tier 2 may be applied for <500kt CO_2 pa installations

Table 7. Recommended tiers of uncertainty for a CCGT, gas-fired CHP or gas-fired CI installations

CO_2 source	Fuel and material type	Uncertainty Tier For Activity Data	Uncertainty Tier For NCV	Uncertainty Tier for Emission Factor	Uncertainty Tier for Oxidation Factor
Generating Units	Gas	4	3	3*	2

***Tier 2 may be applied for all <500kt CO_2 pa installations without site gas composition measurement capability

9. Requirements of the monitoring plan

The monitoring plan is prepared by the operator and approved by the Environment Agency/SEPA before the start of the reporting period, and again after any substantial changes to the monitoring methodology.

Monitoring plans need to be assessed and need new approval before 1/1/2008. Changes in monitoring methodology based on changes in monitoring plans reflecting the transition from the 2004 EU Guidelines to the 2007 EU Guidelines have to take effect before 1/1/2008 – an overlap period during the fourth quarter of 2007 may be required.

The monitoring plan shall contain the following.

a) The description of the installation and activities carried out by the installation.
b) Information on responsibilities for monitoring and reporting within the installation.
c) A list of emission sources and source streams to be monitored for each activity.
d) A description of the calculation based methodology or measurement based methodology to be used. This will include the procedure for determining carbon content of the ash.
e) A list and description of the tiers for activity data, emission factors, oxidation and conversion factors for each of the source streams monitored.
f) A description of the measurement systems, including the specification, uncertainty and exact location of the measurement instruments to be used for each of the source streams monitored.
g) Evidence demonstrating compliance with the uncertainty thresholds for activity data and other parameters for the applied tiers for each source stream.
h) A description of the approach to be used for the sampling of fuel and materials for the determination of net calorific values, carbon content, emission factors, oxidation and conversion factor and biomass content for each of the source streams.
i) A description of the intended sources or analytical approaches for the determination of the net calorific values, carbon content, emission factor, oxidation factor, conversion factor or biomass fraction.
j) A list of non-accredited laboratories used if any.
k) A comprehensive description and uncertainty analysis of any ‘fall back’ approaches used if any.
l) A description of the procedures for data acquisition and handling activities and control activities.
m) Information on relevant links with activities undertaken under the community eco-management and audit scheme (EMAS) and other environmental management systems (e.g. ISO14001:2004), in particular on procedures and controls with relevance to greenhouse gas emissions monitoring and reporting.

For low emission plant (<25 kt CO_2 pa) , the Environment Agency/SEPA may permit a simplified monitoring plan containing only items a), b), c), e), f), k) and l). Requirements are confirmed in the ETS 2.2 Monitoring Plan Template provided by the Environment Agency/SEPA.

The monitoring methodology shall be changed if this improves the accuracy of the reported data, unless this is technically not feasible or would lead to unreasonably high costs. Changes in the monitoring plan which involve substantial changes such as:

- A change in categorisation of the installation: i.e. <50kt CO_2 pa; 50-500 kt CO_2 pa; >500 kt CO_2 pa.;
- A change from the calculation based methodology;
- An increase in the uncertainty of the data used which implies a different tier;

shall be approved by the Environment Agency/SEPA.

The Environment Agency/SEPA shall be notified of other changes without undue delay. These could arise from changes in the data measured; new emission sources; changes in fuel or raw materials; detection of errors resulting from the monitoring methodology

10. Quality assurance, quality control, data acquisition and handling

All power stations perform data management, quality assurance and control processes on their data. In particular, operators will establish, document, implement and maintain:

- Effective data acquisition and handling activities for the monitoring and reporting of greenhouse gas emissions in accordance with the monitoring plan, the permit and the EU Guidelines;
- An effective control system to ensure that the annual emissions report does not contain misstatements and conforms to the monitoring plan, the permit and the EU Guidelines.

The operator's control system consists of the following components:

a) The operators own assessment process of inherent and control risks to errors, misrepresentations or omissions (misstatements) in the annual emissions report and non-conformities against the monitoring plan, the permit and the EU Guidelines.
b) Control activities to mitigate the risks.

The control system shall be evaluated and improved including internal audits of the control system and data to be reported. The control system may make reference to other procedures including the EU Eco-management and Audit Scheme (EMAS), ISO 14001:2004, (Environmental Management Systems -Specification with guidance for use), ISO 9001:2000 and financial control systems.

Responsibilities for the data acquisition and handling activities and control activities are assigned by the operator. These activities are documented as written procedures which include:

- The sequence and interaction of data acquisition and handling activities including methods of calculation or measurement.
- Risk assessment of definition and evaluations of the control system.
- Responsibilities and competences.
- Quality assurance of the measuring equipment and information technology.
- Internal reviews of both reported data and the quality system.
- Out-sourced processes.
- Corrections and corrective action.
- Records and documentation.

The procedures shall mitigate the identified risks.

Measuring equipment shall be calibrated at regular intervals against standards traceable to international standards where available. The monitoring plan will identify components of the measurement instrument which cannot be calibrated and propose alternative procedures. Records of the calibrations are retained for 10 years.

Information technology, including process control computer technology, shall be designed, documented, tested implemented, controlled and maintained to ensure reliable and accurate processing of data. This includes the proper use of calculation formulas. The control of information technology shall include access control, back up, recovery continuity planning and security.

To allow reproducibility of the determination of emissions by the verifier or another third party, power stations shall retain the following for at least ten years after the submission of the CO_2 report.

- A list of all source streams monitored.
- The activity data used for any calculation of the emissions for each source stream, categorised by process and fuel type.
- Documents justifying the selection of the monitoring methodology and the respective proofs of the reasons and any temporal or non-temporal changes of monitoring methodologies and tiers approved by the competent authority.
- Documentation of the monitoring methodology and results from the development of activity specific emission factors and biomass fractions for specific fuels, and oxidation or conversion factors, and respective proofs of approval from the competent authority.
- Documentation of any other changes to the monitoring plan, e.g., notifications.
- Documentation of the process of collection of activity data for the installation and its source streams.
- The activity data, emission, oxidation or conversion factors submitted to the competent authority for the national allocation plan for years preceding the time period covered by the trading scheme.
- Documentation of the responsibilities in connection to the emissions monitoring.
- The annual report.
- Records of all control activities including quality assurance/quality control of equipment and information technology, review and validation of data and corrections. There shall be a procedure to identify, distribute and control the version of these documents.
- And any other information that is identified as required for the verification of the annual emissions report.

The object of the verification is to ensure that emissions have been monitored in accordance with the EU Guidelines and that correct and reliable data are reported. The verifier shall state with reasonable assurance that the data in the emission report is free from material misstatements and whether there are no material non-conformities. Material misstatements refer to omissions, misrepresentations and errors in the annual emissions report which exceed the materiality level. A material non-conformity is any act or omission that is contrary to the monitoring plan and is considered to exceed the materiality level. The materiality levels in the EU Guidelines have been changed to 5% for installations where emissions are equal or less than 500 kt fossil CO_2 pa (categories A and B) and 2% for those plant where emissions are greater than 500 kt fossil CO_2 pa.(category C).

11. Reporting

The reporting template of the Phase 1 EU Guidelines will be used until 31/3/08 i.e. for the reporting year 2007.

There are changes in the new EU Guidelines reporting template but these are unlikely to affect power generators. Additional tables are provided for reporting emissions based on a mass balance approach and also for a CEM measurement approach. It is not expected these would be required for power station emissions.

The reporting forms for biomass consumption have been streamlined.

Where activity data and emission factors are quoted on the basis of mass (or volume) rather than energy, supplementary proxy data for annual average net calorific value and emission factor for each fuel is reported. Proxy data means annual values substantiated empirically or by accepted sources used to substitute data for variables (i.e. fuel/material flow, net calorific value or emission, oxidation or conversion factors) required in the default calculation approaches in order to ensure complete reporting when the monitoring methodology does not generate all required variables.

12. References

BS EN ISO 9001:2000, Quality management systems. Requirements.

BS EN ISO/IEC 17025:2005 General requirements for the competence of testing and calibration laboratories.

BS EN ISO 6974: 2001, ‘Natural gas – determination of composition with defined uncertainty by gas chromatography’, BSI 2001.

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COP/l a, ‘Code of Practice for Low Pressure Diaphragm and Electronic Meter Installations with Badged Meter capacities not exceeding 6 m^3/hr (212 ft^3/hr)’, Ofgas, 1996.

COP/l b, ‘Code of Practice for Low Pressure Diaphragm and Rotary Displacement Meter Installations with Badged Meter capacities exceeding 6 m^3/h (212 ft^3/h), but not exceeding 1076 m^3/h (38,000 ft^3/h), Ofgas, 1996.

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IGE/GM/1, ‘Gas meter installations for pressures not exceeding 100 bar’, Edition 2, Institution of Gas Engineers, Communication 1640, 1998.

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ISO 10723:1995, ‘Natural gas - Performance evaluation for on-line analytical systems’.

ISO 6976:1995, ‘Natural gas – Calculation of calorific values, density, relative density and Wobbe index from composition’, ISO, 1995.
(note the BS equivalent is BS 7859:1996)

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International Institute of Marine Surveyors, ‘Code of Practice for Draught Surveys’, 1998.

JEP MRV Guidance
For EU ETS Phase II

Appendix 1 - Uncertainty Estimation

1. Introduction

2. Results of Uncertainty Estimation
   2.1. Coal
   2.2. Oil
   2.3. Gas

3. Coal Stations
   3.1. Activity Data
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4. Oil Stations
   4.1. Activity Data
   4.2. Emission Factor
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   4.4. NCV

5. Gas Stations
   5.1. Activity Data
   5.2. Emission Factor
   5.3. Oxidation Factor
   5.4. NCV

A1-1 INTRODUCTION

Phase II Monitoring Plans require an estimation of the overall uncertainty in the Activity data, Emission Factor, NCV and Oxidation Factor used to derive a site's annual CO_2 emission.

Several guides to aid uncertainty estimation are available, including the Environment Agency's '*Competent Authority Interpretation the Main Uncertainty Analysis Requirements resulting from the Revised Monitoring & Reporting Guidelines (MRG 2007)*'. This particular reference is most suited to gas-fired installations where uncertainties are solely due to flow meters. For more complex systems, an uncertainty estimation methodology as adopted in BS ISO 5168: 2005 '*Measurement of fluid flow: Procedures for the evaluation of uncertainties*' is used.

The general methodology is as follows:

i) Identify all variables that can affect the result. In the case of calculations, write out the equation. Each variable is a potential *uncertainty source* (u_i).

ii) Assess the *level of uncertainty* for each *uncertainty source*, and note what *units* the uncertainty is stated in.
It is often necessary to further break down each source of uncertainty into its component uncertainties, until a point is reached where uncertainty is clearly defined or easily estimated, e.g.:

$$A = 2B + C$$
↓
$$B = D + E$$
↓
$$E = F*G$$

Uncertainty of B is determined from contributing uncertainties in D & E. In turn, uncertainty in E is determined by knowledge of uncertainties of variables F and G.

iii) For each source of uncertainty, determine whether a *probability devisor* is required to obtain the *standard uncertainty* (std. dev = 1). The most common probability devisors are:
'Normal' – Divide by 2 when an uncertainty is quoted to 95% confidence (i.e. 2 std dev) and a normal probability distribution is expected.
'Rectangular' – Divide by √3 when a random probability distribution is expected.

iv) Determine how a given *unit of uncertainty* in each *uncertainty source* affects the result, i.e. determine the *sensitivity* of the result (c_i) for each *uncertainty source*. This step can also be used to convert uncertainty *units* to a common unit.

v) Determine the *relative standard uncertainty* for each uncertainty source, by combining the *level of uncertainty*, the *probability devisor* and the *sensitivity*.
This step ensures that all uncertainties are on the same basis, in terms of *units* and *degree of confidence* (1 std. dev). **Uncertainties can only be combined if these factors are the same.**

vi) Calculate the *combined standard uncertainty*, by using the root of summed squares principle.

$$u_c = \sqrt{[(c_1*u_1)^2+(c_2*u_2)^2+\ldots]}$$

vii) Report uncertainties as an *Expanded Uncertainty* (U). For reporting uncertainties to 95% confidence, a *coverage factor* (k) of 2 is used.

Expanded Uncertainty = 2 * combined standard uncertainty

A number of CO_2 emissions calculations are based upon cumulative data obtained through the year. In these instances, the uncertainty associated with the yearly average data will be less than the uncertainty associated with individual data points.

This is because any random uncertainties are evened-out by using multiple data points. A standard equation is used in this uncertainty to account for the reduction in uncertainty due to the combination of multiple data. This equation is as follows: -

$$U_{(n)} = \frac{\sqrt{[(U_i * C_i)^2 * n]}}{C_i * n}$$

Where: $U_{(n)}$ = Uncertainty in the average of n values
U_i = Uncertainty in an individual value
C_i = Value
n = no. of individual values

It should be noted that reducing uncertainties in this manner is only applicable where uncertainties are random in nature. Where uncertainties are systematic (i.e. bias) then the uncertainty can not be reduced in this manner. For the following analysis, a conservative approach has been adopted whenever applying this equation.

A1-2 RESULTS OF UNCERTAINTY ESTIMATION

A1-2.1 COAL

The methodology employed to estimate uncertainty in Activity Data, Emission Factor, Oxidation Factor and NCV for CO_2 emissions from coal and solid fuels has been designed to be as widely applicable to all JEP coal-fired power stations as possible.

In effect, all coal-fired stations will be able to apply the basic analysis performed here, provided that they can demonstrate compliance with the following assumptions:

- i) Weighbridge specifications state tolerances to ± 0.5 % or better.
- ii) At least 52 representative proximate analyses are conducted during the reporting period.
- iii) At least 72 representative carbon analyses are conducted during the reporting period.

The following calculation of Activity Data, which produces an uncertainty of 0.7% has included the following assumptions:

- i) No more than 25 % of coal delivered to site will remain on stock rather than being combusted within the reporting period.
- ii) Stock levels will not be more than 25 % of coal consumption over the reporting period (e.g. for a station that consumes 4 Mt coal, the stock level will be no larger than 1 Mt).
- iii) It is assumed that both accurate volumetric and density survey data are available for the majority of the stock (>75%) and that stockpiles for which only accurate volumetric data are available will represent less than 25% of stock tonnage.

It has been highlighted that stock levels can vary considerably between stations, particularly relative to coal consumption. Therefore, to enable each coal station to determine a level of uncertainty relevant to their coal Activity Data, an 'uncertainty calculator' has been provided to accompany this Appendix.

Within the 'uncertainty calculator' stations are requested to enter relatively basic data, which will then calculate the overall level of uncertainty for coal (or solid fuel). In effect, the 'uncertainty calculator' simply determines the relative weightings on delivered uncertainty vs. stock uncertainty. The basic levels of uncertainty (e.g. 0.22% for delivered coal) are derived in the following uncertainty estimation.

In the following analysis, these overall expanded uncertainties have been determined (section A1-3):

Uncertainty in Activity Data (t)	= 0.7 %
Uncertainty in Emission Factor (tCO_2 / t)	= 0.5 %
Uncertainty in Oxidation Factor	= 0.2 %
Uncertainty in NCV (GJ / t)	= 0.2 %

The Uncertainty in Activity Data of approximately ± 0.7 % is within the Tier 4 requirement of ± 1.5 % and therefore coal stations are compliant with the highest tier requirement for Activity Data. The calculation assumes that opening and closing stock levels are no more than 25% of consumption. For higher stock levels the uncertainty will be higher and can be calculated using the JEP uncertainty calculator. Providing stock levels remain lower than 58% of consumption, Tier 4 is achievable.

If stations rely on heat accounting to determine stock levels, rather than relying directly on stock surveys, the uncertainty in Activity Data rises to ± 0.9 %. This is still within the Tier 4 requirement. This can be achieved providing the following assumptions are met:

i) Weighbridge specifications state tolerances to ± 0.5 % or better.
ii) No more than 25 % of coal delivered to site will remain on stock rather than being combusted within the reporting period.
iii) The uncertainty in the stock change calculated by the heat accountancy system is no more than 0.85 % of coal consumption over the reporting period (e.g. for a station that consumes 2 Mt coal, the stock change uncertainty be no larger than ±0.017 Mt)

For higher deliveries to the stock pile and higher stock change uncertainty values, the uncertainty can be calculated using the JEP uncertainty calculator.

Section 13.6 of the EU's revised Monitoring and Reporting Guidelines (MRG 2007) states that the preferred approach to sampling frequency shall be enough to demonstrate that uncertainty in Emission Factor, Oxidation Factor and NCV fall within 1/3rd of the maximum uncertainty required by the approved Tier level for Activity Data; i.e. sampling frequencies shall be such that uncertainties in EF, OF and NCV are 0.5% or less (1/3rd of 1.5%). It should be noted that sampling frequencies employed at coal stations are considerably in excess of the recommended frequencies stated in MRG 2007. Conservative sampling frequencies have been assumed in this uncertainty analysis. The use of Tier 2 for oxidation factor allows the use of the value used in the latest National Inventory submitted to UNFCCC. Thus no uncertainty analysis of OF would be required.

The calculated uncertainty in EF, which relates to the % carbon content of coal, meets this requirement (0.5 % cf. 0.5 %). This is based upon a minimum of 12 samples (monthly composites) of 6 different coal types being analysed in each reporting period. (n.b. The required number of samples to satisfy this uncertainty analysis could also be achieved by performing fewer analyses on a higher number of coals, such that 72 samples are analysed throughout the reporting period).

The calculated uncertainty in OF, which relates to the % carbon-in-ash, meets this requirement (0.2 % cf. 0.5 %). This is based upon a minimum of 12 samples (monthly composites) being analysed in each reporting period.

The calculated uncertainty in NCV meets this requirement (0.2 % cf. 0.5 %). This is based upon a minimum of 52 coal samples being analysed in each reporting period.

A1-2.2 OIL

At oil stations, fuel oil may be metered either by tank level measurements or continuous flow meters, although tank level measurement is more usual. Similar approaches are used at coal stations for metering the fuel oil used for boiler start-up and combustion support and also for open cycle gas turbines operating on gas oil.

Where fuel oil is metered by continuous tank level measurements, the quantities of oil consumed over a period are the differences between tank levels taken between deliveries. At some stations deliveries are estimated from the difference in tank level before and after a delivery. At others an independent estimate of deliveries may be used. The activity uncertainty may depend on variables such as the height and cross section of the storage tanks as well as the way deliveries are measured. Hence a comprehensive calculation of activity uncertainty is not given, nor an oil uncertainty calculator provided. However an example calculation of uncertainties arising from tank level measurements is shown to assist operators to make their own estimates.

For fuel oil (or gas oil) activity measurement in oil station, coal stations and open cycle gas turbines using on-site flow meters, the metering uncertainties quoted in the Competent Authority Guidance can be referenced in Monitoring & Reporting Plans provided that the flow metering installations used for EU ETS reporting are compliant with the Competent Authority Guidance.

Section 13.6 of the EU's revised Monitoring and Reporting Guidelines (MRG 2007) states that the preferred approach to sampling frequency shall be enough to demonstrate that uncertainty in Emission Factor, Oxidation Factor and NCV fall within 1/3rd of the maximum uncertainty required by the approved Tier level for Activity Data; i.e. sampling frequencies shall be such that uncertainties in EF, OF, NCV and other conversion factors are 0.5% or less (1/3rd of 1.5%) for Tier 4.

At oil plants sampling is usually made on delivery. For low load plant there may only be a small number of deliveries each year (e.g. 2 or 3) so each delivery should be sampled.

It is demonstrated below, that the uncertainty criterion is achieved for carbon content (i.e. emission factor) by at least 5 samples per year. Hence more than one sample per delivery may be required. The Tier 3 uncertainty requirement of 0.83% would be achieved by 2 samples, hence it would be sufficient to sample every delivery. For NCV and density it is only necessary to sample each delivery.

An oxidation factor of 1.0 is specified for Tier 2 in the Phase II M&R Guidelines and National Inventory returns. An uncertainty analysis is therefore not required.

A1-2.3 GAS

The uncertainty estimation studies for Activity Data, Emission Factor, Oxidation Factor and NCV relating to CO_2 emissions from gas firing can be referenced by any gas fired station in their Monitoring & Reporting Plans provided that the flow metering installations used for EU ETS reporting are compliant with the specified flow metering and calibration standards, or the Competent Authority Guidance (as appropriate), and the relevant gas analysis calibration standards (as appropriate).

The following overall expanded uncertainties have been determined (section A1-5):

Uncertainty in Activity Data (Sm^3)	= 1.12 %
Uncertainty in Emission Factor (tCO_2 / Sm^3)	= 0.2 %
Uncertainty in Oxidation Factor	= 0.0 %
Uncertainty in NCV (MJ / Sm^3)	= 0.3 %

The Uncertainty in Activity Data of approximately ± 1.1 % is within the Tier 4 requirement of ± 1.5 % and therefore gas stations are compliant with the highest tier requirement for Activity Data.

Section 13.6 of the EU's revised Monitoring and Reporting Guidelines (MRG 2007) states that the preferred approach to sampling frequency shall be enough to demonstrate that uncertainty in Emission Factor, Oxidation Factor and NCV fall within 1/3rd of the maximum uncertainty required by the approved Tier level for Activity Data; i.e. sampling frequencies shall be such that uncertainties in EF, OF and NCV are 0.5% or less (1/3rd of 1.5%).

The calculated uncertainty in EF, which relates to the % carbon content of gas, typically meets this requirement when treated in isolation (0.2 % cf. 0.5 %), when a high quality gas chromatograph is employed for the gas analysis, taking many samples (>100,000) across the year (either conducted by the Operator or the Gas Supplier as part of the billing arrangements). However, the uncertainty rises considerably if a regional average EF is assumed (2.5% cf 0.5%).

An OF of 1.0 is specified for Tier 2 in the Phase II M&R Guidelines and National Inventory returns. An uncertainty analysis is therefore not required and the uncertainty contribution is taken to be zero.

The calculated uncertainty in NCV also individually meets the 1/3rd rule (0.3 % cf. 0.5%) for a high quality chromatograph taking many samples across the reporting period (either conducted by the Operator or the Gas Supplier as part of the billing arrangements). However, the uncertainty rises considerably if a regional average NCV is assumed (1.75% cf 0.5%).

The Combined Uncertainty in EF, OF and NCV equals 0.36 % ($\sqrt{0.22^2+0.02^2+0.32^2}$). This falls within the preferred target uncertainty of 0.5 %. If regional average values of EF and NCV are assumed, this Combined Uncertainty rises to, typically, 3.0%. This gives an Overall Uncertainty in the calculation of CO_2 emission (when combined with activity data) of about 3.25% -somewhat higher than the target value of 2.5% associated with the highest tier activity data. However, in these circumstances, there can be no improvement in the number of samples that are taken for analysis, i.e. the uncertainty is based on the maximum compositional variation between different locations within the region.

A1-3 COAL

A1-3.1 COAL STATIONS - ACTIVITY DATA

A1-3.1.1 Activity Data Calculation

Activity data are expressed in terms of coal consumed (t) during the reporting period. Coal consumed is determined from the amount of coal delivered to site and any change in coal stock level.

Coal consumed (t) = Coal delivered (t) + Starting Stock (t) – Ending Stock (t)

Uncertainty in overall Activity Data is approximately 0.7%, as shown in the table below (for this example – stations can use the 'uncertainty calculator' to determine their own overall uncertainty).

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Coal delivered	0.22 % [a]	2 (normal)	1.25 [c]	0.135
Starting Stock	1.75 % [b]	2 (normal)	0.25 [d]	0.219
Ending Stock	1.75 % [b]	2 (normal)	0.25 [d]	0.219
		Combined Uncertainty		0.337 %
		Expanded Uncertainty		**0.67 %**

[a] See section A1-3.1.2
[b] See section A1-3.1.3
[c] It is assumed that no more than 25% of coal delivered to site will remain on stock rather than being combusted within the reporting period.
[d] It is assumed that stock levels will not be more than 25% of coal consumption over the reporting period (e.g. for a station that consumes 4Mt coal, the stock level will be smaller than 1Mt)

A1-3.1.2 Coal Delivered

The amount of coal delivered is determined by weighing all deliveries on weighbridges. All weight data is recorded and summed over the reporting period.

Rail wagons typically hold 70t coal in 30t wagons (100t gross). Each delivery usually consists of 21 wagons, equating to approximately 1500t per train. Each wagon has four axles, which are weighed individually on entering and leaving the site. Smaller two-axle wagons are also used to deliver coal. Each delivery of 1200t is made up of 36 wagons, which each carry around 35t coal.

Road deliveries are typically 35t coal in 10t lorries (45t gross). Each lorry is weighed on a road weighbridge on entering and leaving the site.

Coal delivered (t) = Weight of wagons & coal – Tare weight of empty wagons

Uncertainty in Mass of a Delivered Coal consignment is 0.75%, as shown in the table below.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Weight of coal + wagons	0.50 % [a]	2 (normal)	100t / 70t	0.357
Weight of wagons	0.50 % [a]	2 (normal)	30t / 70t	0.107
		Combined Uncertainty		0.37 %
		Expanded Uncertainty		**0.75 %**

[a] See section A1-3.1.2.1

While this value could be taken as the overall uncertainty in delivered coal, it is believed that this is unrealistic, since there are many measurements conducted during the year, and therefore any random uncertainties will be reduced.

It is not easy to define uncertainties as random or systematic, so a conservative approach has been adopted. Using the formula below, and assuming just 12 measurements are taken (i.e. at least 12 wagons delivered each year), then the Uncertainty in Delivered Coal drops to 0.22 %.

$$U_{(n)} = \frac{\sqrt{[(U_i * C_i)^2 * n]}}{C_i * n}$$

Where: $U_{(n)}$ = Uncertainty in weight of delivered coal (0.22%)
U_i = Uncertainty in delivery weight for an individual consignment (0.75 %, see above)
C_i = Typical Weight of Coal Delivered
n = no. of individual consignments (12)

This is believed to be conservative because a coal power station will typically record the weight of hundreds of delivery wagons over a year. For stations receiving coal by sea, this approach assumes that coal from at least 12 vessels is weighed during the reporting period.

A1-3.1.2.1 Weighbridge Uncertainty

The declared tolerance on typical weighbridge calibration certificates in the power industry is ±0.5%. This value has been used in the above calculation.

Some sites may wish to use their own weighbridge calibration data to assess weighbridge uncertainty. In such cases, the weighbridge uncertainty should be comprised of a number of factors, including calibration uncertainty, an assessment of maximum drift in calibration between calibrations, measurement repeatability, measurement resolution and any other site-specific uncertainties. An example is shown in the table below. In this example, a reading from the weighbridge will have an uncertainty of ± 0.4%.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Calibration Uncertainty	0.1 % [a]	2 (normal)	1	0.050
Resolution	50 kg [b]	√3 (rectangular)	0.005 %/kg	0.144
Drift from Calibration	0.2%	2 (normal)	1	0.100
Repeatability	15.7 kg [c]	1 (normal)[d]	0.005 %/kg	0.079
		Combined Uncertainty		0.20 %
		Expanded Uncertainty		**0.40 %**

[a] The uncertainty in the reference loads, applied during calibration, is typically less than 0.05% for all calibration methods. IoMC, A Code of Practice for the Calibration of Industrial Process Weighing Systems, WGC0496, Oct 2003.
[b] Weighbridges of the order of 35 tonnes typically have resolution to 20 kg. 50 kg is assumed as a worst case.
[c] (s/√n): A standard deviation (s) of 50 kg over 10 readings (n).
[d] Repeatability is calculated as the standard deviation of a number of readings. The confidence level of this number is therefore 1 s.d. and it is not necessary to divide by 2 as for uncertainties quoted at 95% confidence.

A1-3.1.2.2 Draught Survey

For stations that receive coal by sea, rather than by road or rail, amounts of coal delivered are determined by draught survey. Draught surveys are conducted before and after discharging coal from the vessel. The weight of coal discharged being inferred by the relative displacement of the vessel in the water.

Draught survey accuracy is generally ±0.5% for a well conducted survey (IIMS COP for draught surveys, 1998). This uncertainty is comparable to weighbridge uncertainty used in the Activity Data uncertainty calculations.

A1-3.1.3 Coal Stock Level

Coal stock levels are continually monitored as part of power station heat accountancy practices. Approximately once per year a detailed stock survey is conducted, during which the volume, density and composition of the coal stock will be accurately determined.

If the dates of stock surveys do not correspond with the reporting timescales, then an additional calculation or estimation is required to reconcile the change in stock between the survey and the reporting start or end date. The adjustment of stock volume can be determined in two ways. Firstly, an additional volumetric survey can be completed and an estimate of the stock density is made, based upon previous results. Secondly, the change in coal stock can be determined by comparing heat accountancy calculations of coal burned (GJ) with amounts of coal delivered.

The uncertainty of stock levels (either at start or end of period) is 1.75 %, as shown in the table below.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Volumetric Survey	1.0 % [a]	2 (normal)	1	0.500
Density Survey	1.0 % [b]	2 (normal)	1	0.500
Tonnage adjustment	4.12 % [c]	2 (normal)	0.25 [d]	0.515
		Combined Uncertainty		0.88 %
		Expanded Uncertainty		**1.75 %**

[a] Typical uncertainty quoted for volumetric surveys
[b] Typical uncertainty quoted for density survey
[c] See section A1-3.1.3.1
[d] Assumes that accurate volumetric and density data are available for 75% of the stock tonnage; the adjustment factor only applies to a maximum of 25% of the stock.

A1-3.1.3.1 Tonnage Adjustment – Volumetric Survey & Estimated Density

If a full stock survey is not completed at a suitable time for ETS reporting, an adjustment is required to ascertain the exact stock tonnage. The simplest way of performing this adjustment is to perform another volumetric stock survey and to estimate the density. Since coal stock densities typically fall within 1.1 – 1.3 t/m^3, and do not change significantly over time, this method can be performed without compromising overall uncertainty targets.

The uncertainty of a tonnage adjustment using this approach is 4.12 %.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Volumetric Survey	1.0 % [a]	2 (normal)	1	0.500
Estimated Density	4.0 % [b]	2 (normal)	1	2.000
		Combined Uncertainty		2.06 %
		Expanded Uncertainty		**4.12 %**

[a] Typical uncertainty quoted for volumetric surveys
[b] Estimated worst case uncertainty for estimated density; e.g. if a stockpile's density is estimated at 1.25 t/m^3, then 4% uncertainty means that real density can lie within 1.2-1.3 t/m^3. This is highly likely since coal density tends to fall within narrow bands and a good estimate can be obtained with knowledge of the degree of compaction employed.

A1-3.1.4 Change in Stock Level – Heat Accountancy

If suitable volumetric survey data are not available, operators may wish to use their heat accountancy data to infer the change in coal stock levels.
Coal stocks are monitored by two methods:

(i) The stocks are calculated from the deliveries sent to the stock pile and withdrawals from the stock pile. The deliveries are weighed and the withdrawals are calculated from the heat accounting system based on generation data and an estimation of the heat losses in the system.

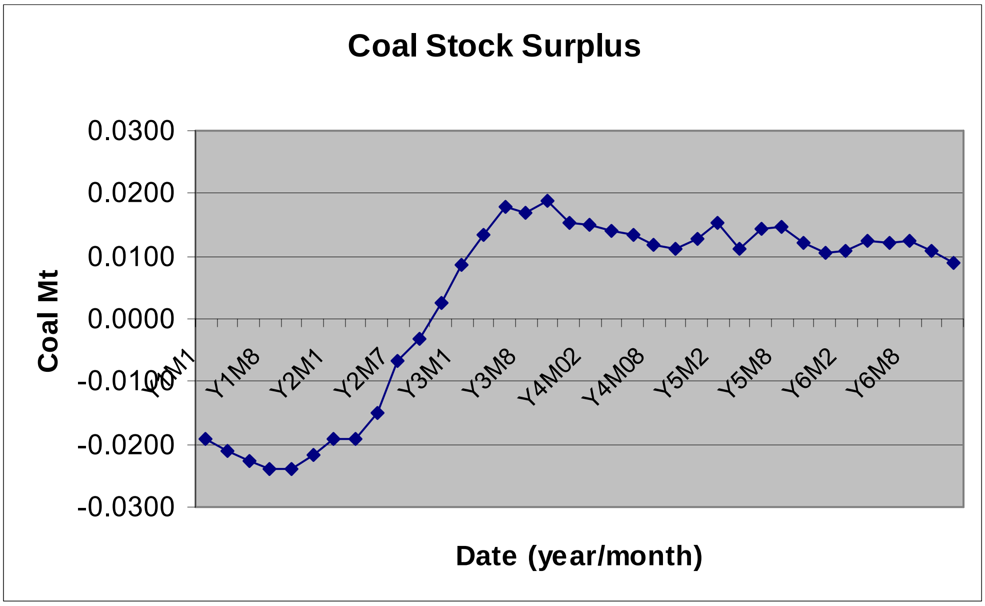
(ii) The stock pile is surveyed regularly (typically every 2 months) and the measured weight is compared with the heat accountancy figure from (i). If these agree to within a specified criterion, typically 5% of the coal stock, no action is taken. Otherwise a stock adjustment is made as a one off consumption figure to bring the heat account stock weight into consistency with the survey.

It is difficult to evaluate the uncertainty in the stock change produced by the heat accountancy system since it is based on many inputs e.g. GW generated, heat losses, steam temperatures etc.

The following procedure may be used to estimate the heat accountancy stock change uncertainty from stock monitoring data.
The stock surplus is defined as:

Stock Surplus = Survey Stock - Heat Accountancy Stock

The stock surplus varies with time taking values close to zero which may be positive or negative. As long as there is no systematic trend away from zero in the long term this indicates that stock changes are estimated without bias. An example plot of stock surplus is shown below.



For the purpose of assessing the effect on emissions over an annual period, the annual rolling stock surplus is appropriate and is defined as.

Annual Rolling Stock Surplus (t) = Stock Surplus (t) –Stock Surplus (t-12 months)

Where Stock Surplus (t) is the stock surplus at a given date and Stock Surplus (t-12) is the stock surplus 12 months earlier. Annual Rolling Stock Surplus is the annual rate of change of the coal stock surplus over successive 12 month periods and reflects the contribution to the annual emission arising from drift in the stock surplus. An example of the calculation of Annual Rolling Stock Surplus is shown in the table below based on data taken over representative years.

Time	Coal Stock Surplus	Annual Rolling Stock Surplus
Year/Month	Mt	Mt
Y1M1	-0.0191	
Y1M3	-0.0211	
Y1M6	-0.0228	
Y1M8	-0.0241	
Y1M10	-0.0241	
Y1M11	-0.0217	
Y2M1	-0.0190	0.00011
Y2M3	-0.0191	0.00197
Y2M5	-0.0151	0.00771
Y2M7	-0.0066	0.01753
Y2M9	-0.0031	0.02104
Y2M11	0.0027	0.02432
Y3M1	0.0087	0.02765
Y3M3	0.0134	0.03253
Y3M5	0.0180	0.03309
Y3M8	0.0171	0.02363
Y3M10	0.0187	0.02176
Y3M12	0.0154	0.01271
Y4M02	0.0149	0.00620
Y4M04	0.0141	0.00068
Y4M06	0.0133	-0.00468
Y4M08	0.0117	-0.00539
Y4M10	0.0113	-0.00741
Y4M12	0.0128	-0.00258
Y5M2	0.0153	0.00043
Y5M4	0.0111	-0.00301
Y5M6	0.0142	0.00090
Y5M8	0.0147	0.00304
Y5M10	0.0122	0.00094
Y5M11	0.0105	-0.00227
Y6M2	0.0108	-0.00450
Y6M4	0.0125	0.00138
Y6M6	0.0122	-0.00199
Y6M8	0.0123	-0.00242
Y6M10	0.0109	-0.00133
Y6M11	0.0089	-0.00167
Standard Deviation		0.01230
U_{RSS}		0.02461

The expanded uncertainty in the Annual Rolling Stock Surplus may be calculated as

U_{RSS} = 2* Standard Deviation (Annual Rolling Stock Surplus (t))

In the above example U_{RSS} has a value of 0.0246 Mt.

The value of the U_{RSS} can be related to the expanded uncertainties in the stock survey stock change U_s and the expanded uncertainty in the heat accountancy stock change U_h by:

$U_{RSS} = \sqrt{(U_s^2 + U_h^2)}$

The value of the stock survey uncertainty needs to be considered. It is assumed that the stock survey stock change uncertainty is the same as the heat accountancy stock change uncertainty (U_s=U_h). This is a conservative assumption, since experience suggests that the heat accountancy estimates are more accurate than the volumetric stock surveys.

$0.0246 = \sqrt{(2U_h^2)}$
$U_h = 0.0174$ Mt

The heat accountancy stock change uncertainty can then be used to estimate consumption uncertainty as shown.

Uncertainty Source	Mass (Mt)	Level of Uncertainty Mt	Level of Uncertainty%	Sensitivity	Expanded Uncertainty %
Coal delivered	2.5	0.0055	0.22 % [a]	1.25 [b]	0.275
Stock change (heat accounting)	0.5	0.0174	3.48 %	0.25 [c]	0.87
Consumption					0.913

[a] See section A1-3.1.2
[b] It is assumed that no more than 0.5Mt of coal delivered to site will remain on stock rather than being combusted within the reporting period, hence coal consumed is 2.5-0.5 =2Mt. The coal delivery is therefore 125% of the consumption.
[c] It is assumed that stock change will not be more than 0.5t i.e. 25% of coal consumption over the reporting period

Here the expanded uncertainty in the fuel consumption is calculated as 0.91% which is within Tier 4. This is based on an uncertainty in the heat accountancy stock change of ±0.0174 Mt.

It follows that if future values of the annual rolling stock surplus were to begin exceed the estimated value of U_{RSS} then this would be an indication that the uncertainty in the heat accounting system was increasing.

A1-3.2 COAL STATIONS – EMISSION FACTOR

A1-3.2.1 Emission Factor Calculation

Emission Factor is reported in terms of tonnes of CO_2 emitted per tonne of coal. This is calculated directly from the % carbon content of coal.

$$\textbf{Emission Factor } (tCO_2 / t) = \frac{\% \text{ carbon (wgt'd)}}{100} * 3.664$$

Uncertainty in EF is due solely to uncertainty in the tonnage-weighted % carbon value, i.e. 0.50 %.

A1-3.2.2 Uncertainty in Tonnage-Weighted % Carbon

% Carbon is determined from the analysis of coal samples. Representative samples of each coal type utilised during a month are submitted for carbon content analysis.

The % carbon value used in the EF calculation is then a tonnage-weighted average of all results.

% Carbon (tonnage weighted) = $(\%C_1*x_1) + (\%C_2*x_2) + (\%C_3*x_3)$…

Where: $\%C_1$ = % carbon for Coal type 1 etc.
x_1 = Coal 1 fraction of total coal consumption etc.

The uncertainty in tonnage-weighted % carbon can be calculated from the component uncertainties in % carbon for individual fuels using the following expression:

$$U_{(n)} = \frac{\sqrt{[(U_i * \%C_i)^2 * n]}}{\%C_i * n}$$

Where: $U_{(n)}$ = Uncertainty in tonnage-weighted % carbon
U_i = Uncertainty in % carbon analysis for an individual coal (1.22 %, see Section A1-3.2.3)
$\%C_i$ = Typical % carbon for an individual coal (65 %)
n = no. of individual coals (6)

If only one coal type is used at a station, then the uncertainty for the tonnage-weighted % carbon will be equal to that of the individual coal. In practice, all stations utilise a range of coal types. For this uncertainty calculation, it is assumed that the site uses six different coal types. As the number of coal types increases, the uncertainty in the average value decreases.

The calculated uncertainty for tonnage-weighted % carbon **= 0.50%.**

A1-3.2.3 Uncertainty in % Carbon for an Individual Coal Type

Usual practice is for carbon analysis to be performed monthly or more for each coal type. The reported %carbon content reported for each coal is therefore an average of at least 12 analyses. The uncertainty in %carbon for a coal type is thus lower than the uncertainty in any single analysis result.

The same equation can be used as above:

$$U_{(n)} = \frac{\sqrt{[(U_i * \%C_i)^2 * n]}}{\%C_i * n}$$

Where: $U_{(n)}$ = Uncertainty in % carbon for an individual coal type
U_i = Uncertainty of % carbon analysis for a single sample (4.23 %, see Section A1-3.4.4)
$\%C_i$ = Typical % carbon for an individual sample (65 %)
n = no. of individual samples (12)

The calculated uncertainty for tonnage-weighted % carbon = 1.22 %.

A1-3.2.4 Uncertainty in % Carbon Analysis for a Single Sample

Uncertainty in the % carbon result for an individual coal sample is comprised from uncertainties in the sampling and analysis of the coal sample and in correcting the analysis result to an as received basis (as analysis is performed on a dry sample).

The calculated uncertainty in an individual % carbon analysis is 4.23%, as shown below.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Sampling – moisture	2 % [a]	√3 (rectangular)	0.1 [d]	0.115
Sampling – ash content	2 % [a]	√3 (rectangular)	0.15 [e]	0.173
Analysis – %C dry	2.51 %C [b]	2 (normal)	100/65 %/%C	1.930
Correction to ar - moisture	1.50 % [c]	2 (normal)	100/90	0.833
		Combined Uncertainty		2.11 %
		Expanded Uncertainty		**4.23 %**

[a] Sampling errors may be introduced due to over- or under-sampling of moisture and/or ash. Automatic coal samplers are routinely tested for bias, with precision of 1% being normally achieved. An uncertainty of 2% has been assumed for sampling uncertainties for both moisture and ash.
[b] Reproducibility for the analysis of a single sample of coal for carbon content is ± 2.51%C dry. ASTM D5373-02: *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen and Nitrogen in Laboratory Samples of Coal and Coke.*
[c] Reproducibility for the analysis of a single sample of coal for Moisture analysis is ± 1.5 %M. BS 1016-104.1: 1999 ISO 11722: 1999 *Methods for analysis and testing of coal and coke – Section 104.1: Determination of moisture content of the general analysis test sample*
[d] A 1% error in moisture will affect the calculated carbon content by 0.1% (for a 10% moisture coal)
[e] A 1% error in ash will affect carbon content by 0.15% (for a 15% ash coal).

A1-3.3 COAL STATIONS – OXIDATION FACTOR

A1-3.3.1 Oxidation Factor Calculation

OF is calculated from the following expression:

$$OF = 1 - \frac{(Cpfa * Wpfa + Cfba * Wfba)}{Wfuel * Cfuel}$$

Where: Cpfa = %Carbon-in-Ash for PFA
Wpfa = Mass of PFA
Cfba = %Carbon-in-Ash for FBA
Wfba = Mass of FBA
Cfuel = % Carbon content of coal
Wfuel = Mass of coal consumed

The calculated uncertainty in OF is 0.16%, as detailed in the table below. This is achieved from 12 monthly composite samples and is within the uncertainty criterion of 1/3rd Tier 4 uncertainty (i.e. within 0.5%).

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Cpfa	0.57 %C [a]	2 (normal)	0.16 %/%C [f]	0.046
Wpfa	2.00 % [b]	2 (normal)	0.02 [f]	0.016
Cfba	0.49 %C [c]	2 (normal)	0.04 %/%C [f]	0.010
Wfba	2.00 % [b]	2 (normal)	0.00 [f]	0.000
Cfuel	0.50 % [d]	2 (normal)	0.02 [f]	0.004
Wfuel	0.67 % [e]	2 (normal)	0.02 [f]	0.006
Rounding Errors	0.001 OF	√3 (rectangular)	102	0.059
		Combined Uncertainty		0.08 %
		Expanded Uncertainty		**0.16 %**

[a] See section A1-3.3.2
[b] Weights of FBA and PFA collected are determined via weighbridge data for ash lorries transporting ash to customers or to disposal sites. Consequently, uncertainties associated with weights of FBA and PFA will be of a similar magnitude to coal delivery data. It is also possible to calculate the weight of ash produced from knowledge of the amount of coal consumed and the ash content of that coal; however, this approach requires an assumption for the distribution of ash between PFA and FBA. Since uncertainties in quantities of PFA and FBA actually have only a minor effect on calculated OF, conservative uncertainties of 2% have been assumed
[c] See section A1-3.3.3
[d] Uncertainty in %carbon content in fuel consumed is as determined for EF (Section A1-3.2.2)
[e] Uncertainty in Wfuel is as determined for Activity Data (Section A1-3.1.2)
[f] Sensitivity analysis has been performed to determine how changes in each of the variables affects the calculated OF. This shows that uncertainty in carbon-in-ash (Cpfa & Cfba) analyses have the most significant effect, see table below:

Uncertainty Source (u_i)	Typical Value	Uncertainty Unit	New Value (high)	Effect on OF	% Difference
Cpfa	10 %C	1 %C	11 %C	**0.9820**	0.162
Wpfa	400,000 te	1 %	404,000 te	**0.9835**	0.016
Cfba	1 %C	1 %C	2 %C	**0.9832**	0.041
Wfba	100,000 te	1 %	101,000 te	**0.9836**	0.000
Cfuel	65 %C	1 %	65.65 %C	**0.9838**	0.017
Wfuel	3,850,000 te	1 %	3,888,500 te	**0.9838**	0.017
OF	**0.9836**				

If Tier 2 is used, the oxidation factor takes the value of that used in the latest National Inventory submission to UNFCCC (0.98 in the 2006 submission). An uncertainty analysis would not be required.

A1-3.3.2 Uncertainty in Cpfa

It is usual practice to analyse at least 12 samples per year (monthly composites). As such, the uncertainty in the average carbon-in-ash result will be lower than the uncertainty for an individual sample.

The same equation as used previously can be applied:

$$U_{(n)} = \frac{\sqrt{[(U_i * Cpfa_i)^2 * n]}}{Cpfa_i * n}$$

Where: $U_{(n)}$ = Uncertainty in average Cpfa over the reporting period
U_i = Uncertainty of %CIA for a single sample (1.97 %C, see Section A1-3.3.2.1)
$Cpfa_i$ = Typical %CIA for an individual sample (10 %C)
n = no. of individual samples (12)

The calculated uncertainty for Cpfa = 0.57 %C.

A1-3.3.2.1 Uncertainty in %Carbon-in-ash for a Single PFA sample

The uncertainty in %CIA for a given sample is made up of uncertainties in the sampling and the analysis of the sample. The combined uncertainty is calculated as 1.97 %C, as shown in the table below.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
PFA sampling	10 % [a]	2 (normal)	0.1 %C/% [c]	0.500
CIA Analysis	1.69 %C [b]	2 (normal)	1	0.847
		Combined Uncertainty		0.98 %C
		Expanded Uncertainty		**1.97 %C**

[a] Each sample of PFA analysed is a composite sample made up over a period of time (typically one month). By sampling regularly (i.e. daily), the PFA composite will be representative of the different coal types consumed over that period. Despite this, uncertainties due to unrepresentative sampling have been considered. A conservative estimate is that these uncertainties will not affect the %CIA result by more than 10% (relative).
[b] See section A1-3.3.4
[c] 1% error in sampling will affect the Cpfa by 0.1%C for a 10% carbon content ash.

A1-3.3.3 Uncertainty in Cfba

This uncertainty analysis assumes that sites analyse FBA for carbon content. Assuming monthly samples are analysed, the same approach as for PFA can be adopted.

$$U_{(n)} = \frac{\sqrt{[(U_i * Cfba_i)^2 * n]}}{Cfba_i * n}$$

Where: $U_{(n)}$ = Uncertainty in average Cfba over the reporting period
U_i = Uncertainty of %CIA for a single sample (1.70 %C, see Section A1-3.3.3.1)
$Cfba_i$ = Typical %CIA for an individual sample (1 %C)
n = no. of individual samples (12)

The calculated uncertainty for Cfba = 0.49 %C

A1-3.3.3.1 Uncertainty in %Carbon-in-ash for a Single FBA sample

The uncertainty in %CIA for a given sample is made up of uncertainties in the sampling and the analysis of the sample. The combined uncertainty is calculated as 1.70 %C.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
FBA sampling	10 % [a]	2 (normal)	0.01 %C/% [c]	0.050
CIA Analysis	1.69 %C [b]	2 (normal)	1	0.847
		Combined Uncertainty		0.85 %C
		Expanded Uncertainty		**1.70 %C**

[a] Each sample of FBA analysed is a composite sample made up over a period of time (typically one month). FBA is generally of more homogeneous composition than PFA, although regular sampling is required to ensure that the FBA is representative of the range of coals consumed. A conservative estimate is that these uncertainties due to sampling will not affect the %CIA result by more than 10% (relative).
[b] See section A1-3.3.4
[c] 1% error in sampling will affect the Cfba by 0.01%C for a 1% carbon content ash.

A1-3.3.4 Uncertainty in CIA Analysis

The procedure for determination of carbon-in-ash is as described in BS EN 196-2: 2005 (Section 7). The process involves measuring the mass of a dried ash sample before and after combustible material is combusted.

$$\%CIA = \frac{(M2 - M3)}{(M2 - M1)} * 100$$

where: M1 = weight of pot (dried)
M2 = weight of pot + dried sample
M3 = weight of pot + combusted sample

The calculated uncertainty in a CIA analysis is 1.69%.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
M1 (weight of pot)	0.012 g [a]	2 (normal)	10 %C / g [b]	0.060
M2 (weight of pot + dry ash)	0.012 g [a]	2 (normal)	100 %C/g [c]	0.597
M3 (weight of pot + com-busted ash)	0.012 g [a]	2 (normal)	100 %C/g [c]	0.597
		Combined Uncertainty		0.85 %C
		Expanded Uncertainty		**1.69 %C**

[a] See Section A1-3.3.4.1
[b] 0.01 g error in the pot weight could affect the calculated %CIA by up to 0.1%C; i.e. 10 %C/g
[c] 0.01 g error in the either start or end weight of sample could affect the calculated %CIA by up to 1%C; i.e. 100 %C/g

A1-3.3.4.1 Uncertainty of Mass Measurements during CIA Analysis

The uncertainty of the weights taken during CIA analysis will primarily be due to uncertainties associated with the balance being used. This uncertainty has been calculated as 0.012 g for a calibrated 3 decimal place balance.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Balance Calibration	0.01 g [a]	2 (normal)	1	0.005
Resolution	0.001 g [b]	√3 (rectangular)	1	0.001
Measurement Repeatability	0.003 g [c]	1 (normal)	1	0.003
		Combined Uncertainty		0.006 g
		Expanded Uncertainty		**0.012 g**

[a] Uncertainty due to calibration uncertainty and any drift from calibration between calibrations is likely to be well within 0.01 g for a 3 or 4 decimal place balance
[b] Resolution of 3 decimal place balance is to the nearest 0.001 g. Normally a 4 decimal place balance would be used to perform CIA analysis
[c] (s/√n): A standard deviation (s) of 0.001 g over 10 readings (n).

A1-3.4 COAL STATIONS – NCV

A1-3.4.1 Average NCV

Average NCV is calculated by averaging NCV values of samples analysed through the reporting year. As such, the uncertainty in the average NCV result will be lower than the uncertainty for any individual sample. The NCV sampling approach does not discriminate between coals (in contrast to the carbon content).

The same equation as used previously can be applied:

$$U_{(n)} = \frac{\sqrt{[(U_i * NCV)^2 * n]}}{NCV * n}$$

Where: $U_{(n)}$ = Uncertainty in average NCV over the reporting period
U_i = Uncertainty in NCV for a single sample (1.35%)
NCV = Typical NCV for an individual sample (25000 kJ/kg)
n = no. of individual samples (52)

It is assumed that at least one sample is analysed each week. The calculated uncertainty for NCV = 0.19 %. For monthly sampling the uncertainty would be 0.39%.

A1-3.4.2 Uncertainty in an Individual NCV result

Coal is purchased on the basis of net calorific value (NCV), since this property describes the useful heat inherent in the coal. However, it is not possible to determine NCV directly; instead an equation must be used to convert GCV, which is measured in a bomb calorimeter, to NCV.

NCV = GCV - (212.1*ar H) - (24.4*(ar M + 0.1*ar A)) - 6

Where: NCV = Net Calorific Value, kJ/kg
GCV = Gross Calorific Value, kJ/kg
ar H = as received hydrogen, %H
ar M = as received moisture, %M
ar A = as received ash, %A

The uncertainty in NCV is calculated from the uncertainties in each of these variables. For a single sample, the calculated uncertainty in NCV is 1.35%. This shows that the conversion from GCV to NCV introduces a negligible increase in uncertainty.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
GCV	330.37 kJ/kg [a]	2 (normal)	0.004 %/kJ/kg [e]	0.666
ar H	2.81 % [b]	2 (normal)	0.036 [e]	0.050
ar M	15.18 % [c]	2 (normal)	0.011 [e]	0.082
ar A	4.14 % [d]	2 (normal)	0.001 [e]	0.002
Rounding Errors	10 kJ/kg	√3 (rectangular)	0.004 %/kJ/kg	0.024
		Combined Uncertainty		0.67 %
		Expanded Uncertainty		**1.35 %**

[a] See Section A1-3.4.3
[b] See Section A1.3.4.7
[c] See Section A1-3.4.4
[d] See Section A1-3.4.5
[e] Sensitivity analysis has been performed to determine how changes in each of the variables affects the calculated OF, see table below:

Uncertainty Source (u_i)	Typical Value	Uncertainty Unit	New Value (high)	Effect on NCV	% Difference
GCV	26000 kJ/kg	1 kJ/kg	26001	**24811**	-0.004
ar H	4.2 %H	1 %	4.242	**24801**	0.036
ar M	11 %M	1 %	11.11	**24808**	0.011
ar A	10 %A	1 %	10.1	**24810**	0.001
NCV	**24810 kJ/kg**				

A1-3.4.3 Uncertainty in GCV

Uncertainty in the GCV result is affected by uncertainties in sampling and analysis. The overall uncertainty for a single sample is ± 330 kJ/kg, as shown in the table below.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Sampling – moisture	2 % [a]	√3 (rectangular)	33 kJ/kg /% [c]	38
Sampling – ash	2 % [a]	√3 (rectangular)	50 kJ/kg /% [d]	58
GCV analysis	300 kJ/kg [b]	2 (normal)	1	150
		Combined Uncertainty		165.18 kJ/kg
		Expanded Uncertainty		**330.37 kJ/kg**

[a] Sampling errors may be introduced due to over- or under-sampling of moisture and/or ash. Automatic coal samplers are routinely tested for bias, with precision of 1% being normally achieved. An uncertainty of 2% has been assumed for sampling uncertainties for both moisture and ash.
[b] Reproducibility for the analysis of a single sample of coal for Gross Calorific Value is ± 300 kJ/kg at 95% confidence. *BS 1016-105: 1992 Methods for analysis and testing of coal and coke. Determination of Gross Calorific Value*
[d] A 1% error in moisture will affect the calculated GCV by 33 kJ/kg (for a 10% moisture coal)
[e] A 1% error in ash will affect the calculated GCV by 50 kJ/kg (for a 15% ash coal)

A1-3.4.4 Uncertainty in Moisture

Uncertainty in the moisture analysis result is affected by uncertainties in sampling and analysis. The overall uncertainty for a single sample is ± 15.2%, as shown in the table below.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Sampling – moisture	2 % [a]	√3 (rectangular)	1	1.155
Moisture analysis	1.50 %M [b]	2 (normal)	10 % /%M [c]	7.500
		Combined Uncertainty		7.59 %
		Expanded Uncertainty		**15.18 %**

[a] Sampling errors may be introduced due to over- or under-sampling of moisture. Automatic coal samplers are routinely tested for bias, with precision of 1% being normally achieved. An uncertainty of 2% has been assumed for sampling uncertainties for moisture.
[b] Reproducibility for the analysis of a single sample of coal for Moisture analysis is ± 1.5 %M. BS 1016-104.1: 1999 ISO 11722: 1999 *Methods for analysis and testing of coal and coke – Section 104.1: Determination of moisture content of the general analysis test sample*
[d] A 1% error in moisture will affect the calculated moisture by 10 %M (for a 10% moisture coal)

A1-3.4.5 Uncertainty in Ash

Uncertainty in the ash analysis result is affected by uncertainties in sampling and analysis. The overall uncertainty for a single sample is ± 4.14%, as shown in the table below.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Sampling – ash	2 % [a]	√3 (rectangular)	1	1.155
Ash analysis (dry)	3.0 % [b]	2 (normal)	1	1.500
Moisture correction to ar	1.50 %M [c]	2 (normal)	100/90 % / %M [d]	0.833
		Combined Uncertainty		2.07 %
		Expanded Uncertainty		**4.14 %**

[a] Sampling errors may be introduced due to over- or under-sampling of ash. Automatic coal samplers are routinely tested for bias, with precision of 1% being normally achieved. An uncertainty of 2% has been assumed for sampling uncertainties for ash.
[b] Reproducibility for the analysis of a single sample of coal for ash analysis is ± 0.3 %A or 3% relative, whichever is greater. BS 1016-104.4: 1998 ISO 1171: 1997 *Methods for analysis and testing of coal and coke – Section 104.4: Determination of ash content*
[c] Reproducibility for the analysis of a single sample of coal for Moisture analysis is ± 1.5 %M. BS 1016-104.1: 1999 ISO 11722: 1999 *Methods for analysis and testing of coal and coke – Section 104.1: Determination of moisture content of the general analysis test sample*
[d] A 1% error in ash will affect the calculated moisture by 10 %M (for a 10% moisture coal)

A1-3.4.6 Uncertainty in Volatile Matter

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
Sampling – moisture	2 % [a]	√3 (rectangular)	1	0.155
Sampling – ash	2 % [a]	√3 (rectangular)	1	0.173
Analysis - VM (dry)	4.0 % [b]	2 (normal)	1	2.000
Moisture correction to ar	1.50 %M [c]	2 (normal)	100/90 % / %M	0.825
		Combined Uncertainty		2.17 %
		Expanded Uncertainty		**4.35 %**

[a] Sampling errors may be introduced due to over- or under-sampling of moisture and/or ash. Automatic coal samplers are routinely tested for bias, with precision of 1% being normally achieved. An uncertainty of 2% has been assumed for sampling uncertainties for ash and moisture.
[b] Reproducibility for the analysis of a single sample of coal for volatile content is ± 0.5 %VM or 4 % relative, whichever is greater. BS 1016-104.3: 1998, ISO 562: 1998 *Methods for analysis and testing of coal and coke – Section 104.3: Determination of volatile matter content*
[c] Reproducibility for the analysis of a single sample of coal for Moisture analysis is ± 1.5 %M. BS 1016-104.1: 1999 ISO 11722: 1999 *Methods for analysis and testing of coal and coke – Section 104.1: Determination of moisture content of the general analysis test sample*

A1-3.4.7 Uncertainty in As-Received Hydrogen

As with NCV, coal hydrogen content is not routinely determined. Instead an established calculation is used.

$$\text{ar H} = \frac{(0.036 * \text{GCV} + 13.8 * \text{ar V} + 5.56 * \text{ar A} + 6.2\ 8\ \text{ar M} - 625)}{212.1}$$

The uncertainty in ar H is therefore calculated from the uncertainties in the component variables.

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Sensitivity	Relative Standard Uncertainty
GCV	330.37 kJ/kg [a]	2 (normal)	0.0042 [e]	0.690
ar V	4.35 % [b]	2 (normal)	0.4963 [e]	1.079
ar A	4.14 % [c]	2 (normal)	0.0710 [e]	0.147
ar M	15.18 % [d]	2 (normal)	0.0719 [e]	0.546
Rounding Errors	0.01 %H	√3 (rectangular)	23.81 %/%H	0.137
		Combined Uncertainty		1.41 %
		Expanded Uncertainty		**2.81 %**

[a] See Section A1-3.4.3
[b] See Section A1-3.4.6
[c] See Section A1-3.4.5
[d] See Section A1-3.4.4
[e] Sensitivity analysis has been performed to determine how changes in each of the variables affects the calculated ar H, see table below:

Uncertainty Source (u_i)	Typical Value	Uncertainty Unit	New Value (high)	Effect on NCV	% Difference
GCV	26000 kJ/kg	1 kJ/kg	26001	**4.0641**	-0.0042
ar V	31 %	1 %	31.31	**4.0841**	-0.4963
ar A	11 %M	1 %	11.11	**4.0668**	-0.0710
ar M	10 %A	1 %	10.1	**4.0669**	-0.0719
NCV	**4.0639 %**				

A1-4 OIL

A1-4.1 OIL STATIONS - ACTIVITY DATA

At oil stations, fuel oil may be metered either by tank level measurements or continuous flow meters, although tank level measurement is more usual. Similar approaches are used at coal stations for metering the fuel oil used for boiler start-up and combustion support and also for open cycle gas turbines operating on gas oil.

A1-4.1.1 Tank Level Measurement

At an oil station, fuel oil is usually metered by continuous tank level measurements. Measurement may be either by dipping i.e. the height of the liquid above a datum, or by ullaging i.e. the distance of the liquid surface below a datum. Hence the quantities of oil consumed over a period are the differences between tank levels taken between deliveries. At some stations, deliveries are estimated from the difference in tank level before and after a delivery. Assuming that oil deliveries to a tank do not occur while it is in use, the consumption will be based on the differences between a number of tank level measurements. The following calculation is an example of how uncertainty may be estimated from such data. The uncertainties are defined as expanded uncertainties i.e. ±2*standard deviation or when in dimensionless form ± 2* standard deviation/mean.

Tank levels should be measurable to an uncertainty of ±3mm, though older technologies or tank designs which allow movement of the datum point due to flexing of the tank shell will be worse than this[2]. Tank levels are converted to volumes by a tank calibration table.

If the level meter uncertainty is ± 3mm, then for a tank of 17m depth and diameter 37m, the uncertainty corresponds to ± 3.2 m^3. For a low load station the number of deliveries can be small, maybe only 3 per year. A simplified calculation is shown in the table. Here the quantities x_i are the volumes of oil used between deliveries. The quantities may be drawn from more than one tank.

Period	x_i (m^3)	Expanded Uncertainty (m^3)	Expanded Uncertainty (t)	Expanded Uncertainty U_i %	$U_i.x_i\ \rho_i$ (t)	$(U_i.x_i\ \rho_i)^2$
1	8000	4.56	27.7	0.35	2773	7.69×10^6
2	3000	4.56	27.7	0.94	2773	7.69×10^6
3	2000	4.56	27.7	1.41	2773	7.69×10^6
4	7000	4.56	27.7	0.40	2773	7.69×10^6
5	8000	4.56	27.7	0.35	2773	7.69×10^6
∑	28000					38.5×10^6
$\sqrt{\sum(U_i.x_i\ \rho_i)^2}$						6201
$U_{Act} = \sqrt{\sum(U_i.x_i\ \rho_i)^2}/\sum x_i\ \rho_i$						0.23%

The uncertainty in the quantities will be the difference between two tank levels. If the uncertainty in a tank level measurement is equivalent to ± 3.2 m^{-3}, the uncertainty in the quantities (i.e. the difference between two levels) will be ± $\sqrt{(3.2^2+3.2^2)}$ = 4.56 m^3. Oil volumes are converted to mass using the measured density of the oil (ρ_i assumed to be 0.98 t/m^3 in the example). As discussed in A1.4.4.2 there will be an uncertainty of ±0.15% in the density estimate arising from uncertainty in temperature measurement. Taking the worse case of a full tank this corresponds to a mass of $17*37^2*\pi/4*0.98*0.0015$=27.4 t. Hence the uncertainty in the quantities is ± $\sqrt{((0.98*4.56)^2+27.4^2)}$ = 27.7 t. The expanded uncertainty U_i is then calculated as 27.7/($x_i\ \rho_i$.). It follows that if all the U_i are within the tier uncertainty criterion, then total activity uncertainty U_{Act} will also be. Otherwise the uncertainties can be combined as shown to give the overall uncertainty. In this example the total uncertainty in the oil consumption is 0.22%.

If deliveries occur during operation then the delivery quantity would be based on the supplier's data or an independent survey validation of the delivery note may be made and so the delivery uncertainty may differ from the level meter uncertainty.

For example, a delivery of 10000 m^3 of oil during the first period in the example above could occur. If the uncertainty in the delivery was ± 0.7%, this would correspond to ± 70 m^3 or ± 68.6 t. Assuming the uncertainty arising from the density estimate is ±0.15% then this would correspond to a mass of 10000*0.98* 0.0015 = ±14.7t. The uncertainty in the mass of the delivery is then $\pm\sqrt{(68.6^2+14.7^2)}$ = ±70.2 t. The uncertainty in the consumption in the first period would become $\pm\sqrt{(27.7^2+70.2^2)}$=75.5 t. The example would then become.

[2] A guide to recommended measurement practice for compliance with the requirements of HMC&E notice 179. Petroleum Measurement Paper No 7, Institute of Petroleum

	x_i (m^3)	Expanded Uncertainty (m^3)	Expanded Uncertainty (t)	Expanded Uncertainty U_i %	$U_i.x_i\,\rho_i$	$(U_i.x_i\,\rho_i)^2$
1	8000	70.1	75.5	0.96	7549	57.0×10^6
2	3000	4.56	27.7	0.94	2773	7.69×10^6
3	2000	4.56	27.7	1.41	2773	7.69×10^6
4	7000	4.56	27.7	0.40	2773	7.69×10^6
5	8000	4.56	27.7	0.35	2773	7.69×10^6
∑	28000					87.8×10^6
$\sqrt{\sum(U_i.x_i\,\rho_i)^2}$						9368
$U_{Act} = \sqrt{\sum(U_i.x_i\,\rho_i)^2} / \sum x_i\,\rho_i$						0.34%

The overall uncertainty in the fuel consumption increases to 0.34% because of the delivery. Evidence will be required for the uncertainties of the level meter and the delivery. Expert judgement can be used if equipment suppliers' data is not available.

A1-4.1.2 Flow Metering

The Competent Authority has determined that various types of volume flow meters that are operated and maintained to the Original Equipment Manufacturer's (OEM's) instructions can be assigned a fixed uncertainty[3], as shown in the table below.

Meter type	Expanded Uncertainty	Frequency of calibration/ cleaning	Life span of meter	Other
Turbine	0.3	< 5 years	25 years	Three monthly lubrication of bearings (if not permanently lubricated);
Orifice	1.5	< 5 years	25 years	Annual calibration of ΔP meter and inspection of orifice/mountings; annual maintenance to OEM specification.
Venturi	1.5	< 5 years	30 years	Annual calibration of ΔP meter and inspection of orifice/mountings; annual maintenance to OEM specification.
Ultrasonic	0.5	< 5 years	15 years	Annual inspection of transducers and state of wall; annual maintenance to OEM specification.
Coriolos	1	< 5 years	10 years	Annual check of sensors and transmitters; annual maintenance to OEM specification; monthly zero check.
Vortex	1.5	< 5 years	10 years	Annual inspection; annual maintenance to OEM specification; set up vibration free.
Ovalrad	0.5	< 5 years	30 years	Annual inspection; annual maintenance to OEM specification.

Provided that the meter is operated in accordance with the above listed requirements, a more detailed uncertainty analysis is not required, although evidence of calibration and associated tolerances must be provided by the Operator. In all circumstances, flow metering that is based on the measurement of differential pressure requires an annual calibration of the pressure sensor. For liquid fuels the uncertainties in the table can be applied without further adjustments for uncertainty in temperature and pressure. The mass flow measurements derived from the meter readings require the oil density which is derived from temperature measurements taken automatically at the meter or in the supply line. It follows that use of any of the meters listed and compliance with the conditions is sufficient to achieve Tier 4.

[3] Competent Authority Interpretation the Main Uncertainty Analysis Requirements resulting from the Revised Monitoring and Reporting Guidelines (MRG 2007), Version 1.1 (28.06.07), Environment Agency, Scottish Environment Protection Agency, Environment & Heritage Service.

A1-4.2 OIL STATIONS - EMISSION FACTOR

A1-4.2.1 Uncertainty in % Carbon

For fuel oil homogeneity can be assumed due to mixing. The proportions of water and ash in fuel oil are very small and are unlikely to influence the uncertainty in carbon content. The uncertainty in a single carbon content determination can be estimated as.

Uncertainty Source (u_i)	**Level of Uncertainty**	**Probability Divisor**	**Relative Standard Uncertainty**
Analysis – %C dry	1.16 %C [a]	2 (normal)	0.58
		Combined Uncertainty	0.58 %
		Expanded Uncertainty	**1.16 %**

a Repeatability for the analysis of a single sample of oil for carbon content is ± 1.16%C for a carbon content of 80%. ASTM D5291-02: *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen and Nitrogen in Petroleum Products and Lubricants.*

Oil is normally sampled on delivery, and for a low load station the number of deliveries may be small. The uncertainty is based on the repeatability of the standard method since an operator is unlikely to use different laboratories for a relatively small number of samples. For a simple case such as this, the uncertainty in the carbon content estimated from n samples from deliveries of similar amounts will vary as $\sqrt{n}$. The criterion of 0.5% uncertainty for Tier 4 would be achieved by 5 samples. Hence sampling each delivery and ensuring the total number of samples per year is at least 5, is sufficient to achieve the Tier 4 uncertainty requirement. The Tier 3 uncertainty requirement of 0.83% would be achieved by 2 samples, hence it would be sufficient to sample every delivery.

A1-4.3 OIL STATIONS – OXIDATION FACTOR

An oxidation factor of 1.0 is specified for Tier 2 in the Phase II M&R Guidelines and National Inventory returns. An uncertainty analysis is therefore not required.

A1-4.4 OIL STATIONS - NCV

A1-4.4.1 Uncertainty in NCV Determination

The uncertainty in a single GCV determination can be estimated as

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Relative Standard Uncertainty
Analysis – %GCV	0.325 %GCV [a]	2 (normal)	0.16
		Combined Uncertainty	0.16 %
		Expanded Uncertainty	**0.325 %**

a Repeatability for the analysis of a single sample of oil for carbon content is ± 130 J/g. ASTM D240-02: *Standard Test Methods for Heat of Combustion of liquid hydrocarbon fuels by bomb calorimeter.* A GCV of 40000 J/g is assumed.

It is shown in A1-3.4.2 that for coal the uncertainty in the GCV estimate is only slightly greater than the NCV uncertainty due to uncertainties arising mainly from the ash and water contents of the coal. Since the water and ash contents of oil are much lower, the uncertainty in the GCV determination will not be significantly greater. Since the uncertainty in the NCV is less than the Tier 4 criterion of 0.5% it is sufficient to sample every oil delivery.

A1-4.4.2 Uncertainty in Density

The uncertainty in a single density determination can be estimated as

Uncertainty Source (u_i)	Level of Uncertainty	Probability Divisor	Relative Standard Uncertainty
Analysis – %ρ	0.061 %ρ [a]	2 (normal)	0.031
Temperature	0.14%ρ [b]	2 (normal)	0.07
		Combined Uncertainty	0.076 %
		Expanded Uncertainty	**0.15 %**

a Repeatability for the analysis of a single sample of oil for density (ρ) is ± 0.0006 g/ml. IP 160 Crude Petroleum and Liquid Petroleum Products Laboratory Determination of Density Hydrometer Method. A density of 0.98g/ml is assumed.
b Based on an uncertainty in temperature measurement of ±2K and IP correction tables.

Since the uncertainty in the density is less than the Tier 4 criterion of 0.5% it is sufficient to sample every oil delivery.
In practice the uncertainty in the oil density is influenced by the uncertainty in the measurement of the oil temperature. Automatic temperature measurement systems can measure average tank temperatures to ±0.5K. However, allowing for climactic conditions, product variations, the maximum deviation of such systems from reference measurements may be as much as ±2K for heated systems.[2] Hence an uncertainty of ±2K has been assumed in calculating the density uncertainty.

A1-5 GAS

A1-5.1 GAS STATIONS – ACTIVITY DATA

Activity data are based on the volumetric flow metering of natural gas. Consumption data are expressed as m^3 at 15°C and 101.325 kPa during the reporting period.

A1-5.1.1 On-Site Metering

The Competent Authority has determined that various types of volume flow meters that are operated and maintained to the Original Equipment Manufacturer's (OEM's) instructions can be assigned a fixed uncertainty[4], as shown in the table below.

Meter type	Expanded Uncertainty	Uncertainty with EVCI	Frequency of calibration/ cleaning	Life span of meter	Other
Turbine	1.5	1.58	< 5 years	25 years	Annual visual inspection; three monthly lubrication of bearings (if not permanently lubricated); pulsation free flow.
Orifice	1.5	1.58	< 5 years	25 years	Annual calibration of ΔP meter and inspection of orifice/mountings; annual maintenance to OEM specification.
Venturi	1.5	1.58	< 5 years	30 years	Annual calibration of ΔP meter and inspection of orifice/mountings; annual maintenance to OEM specification.
Ultrasonic	0.5	0.71	< 5 years	15 years	Annual inspection of transducers and state of wall; annual maintenance to OEM specification.
Coriolos	1	1.12	< 5 years	10 years	Annual check of sensors and transmitters; annual maintenance to OEM specification; monthly zero check.
EVCI	0.5	0.71	< 4 years	10 years	Annual inspection and maintenance to OEM specification.

Provided that the meter is operated in accordance with the above listed requirements, a more detailed uncertainty analysis is not required, although evidence of calibration and associated tolerances must be provided by the Operator. In all circumstances, flow metering that is based on the measurement of differential pressure requires an annual calibration of the pressure sensor.

It is assumed that fuel gas flow meters within power stations are always compensated for temperature and pressure. If the meter is fitted with an Electronic Volume Conversion Instrument (EVCI)[5], a fixed uncertainty of 0.5% can be assumed, as shown in the table. Although the Guidance[4] restricts the prescribed uncertainty to EVCIs with a pressure less than 11 bar, this approach can be applied at higher pressures and it is reasonable to apply the same uncertainty, as a worst case, when using flow computers[5], provided that the relevant standards are adhered to, as discussed below. The uncertainty associated with the calculations performed by flow computers is better than 0.001%[6] and it therefore follows that the bulk of the uncertainty is linked to the measurement of temperature, pressure and, in some

[4] Competent Authority Interpretation the Main Uncertainty Analysis Requirements resulting from the Revised Monitoring and Reporting Guidelines (MRG 2007), Version 1.1 (28.06.07), Environment Agency, Scottish Environment Protection Agency, Environment & Heritage Service.
[5] Selection, installation and use of electronic gas meter volume conversion systems, IGE/GM/5 Edition 2.
[6] Flow metering practices for pressures between 38 and 250 bar, IGE/GM4

cases, fluid density, noting that an assumed or calculated compressibility factor is normally required at industrial gas pressures.

From first principles, a temperature error of 0.5°C is equivalent to a flow correction error of about 0.2%. Similarly, an error in the absolute pressure measurement of 0.2% is equivalent to a flow measurement error of 0.2%. Calibrated PRTs or thermocouples deliver an uncertainty better than 0.2°C and calibrated pressure transducers deliver an uncertainty better than 0.1% of full scale. Provided that calibrations are undertaken and maintained to appropriate standards it is evident that the conservative assumption of 0.5% for the volume flow correction factor is achieved.

When the EVCI or flow computer uncertainty is combined with the assumed metering uncertainty, it can be seen, from the table, that only Ultrasonic and Coriolis meters meet the top tier uncertainty level of 1.5%.

Further analysis is therefore required for other meter types as follows:

A1-5.1.1.1 Orifice meters

The main protocol text points out that flow metering for installations within the Electricity Supply Industry is covered by IGE/GM/4, 1996 and the Ofgem Code of Practice COP1c, 1996. IGE/GM/4 is mandatory for meters covered by COP1c, with a capacity greater than 1076 m^3/h, equivalent to a installations thermal input of about 10MW gross (about 20ktCO_2/annum).

This standard states that an uncertainty of ±1% can be achieved without flow calibration of the primary device. This requires that the orifice plate is designed, manufactured and installed to ISO 5167-1(1991) which is directly equivalent to BS1042 Part 1, Section 1.1 (1992). This 1% overall uncertainty is associated with the complete flow metering system, including the secondary instrumentation. The meter uncertainty is comprised of 0.6 to 0.75% for the discharge coefficient, 0.1% for elastic deformation of the orifice plate and the fact that calibration laboratories, generally, have an uncertainty of about 0.3%. A conservative assumption, for the meter alone, of 1% is therefore adopted here, recognising that the Operator must demonstrate that the installation is compliant with BS1042.

A conservative overall uncertainty of a compliant orifice plate meter fitted with pressure and temperature correction is therefore estimated to be 1.12%.

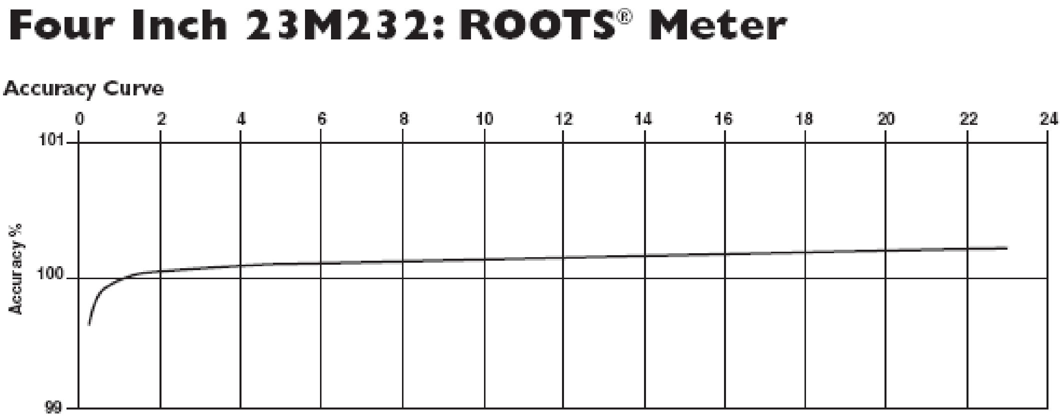
A1-5.1.1.2 Turbine meters

The meter should again be designed and manufactured to an appropriate standard such as BS 4161: Part 6 or ISO 9951. However, in this case, a calibration is recommended at the working conditions of the meter in order to achieve a calibration uncertainty of 0.5 to 1.0%[6]. The condition of the bearings should be checked periodically in order to maintain performance, noting that a second turbine wheel, rotating at a different speed to the first, can be incorporated into the design as a means of monitoring bearing degradation.

A conservative overall uncertainty of a compliant turbine meter fitted with pressure and temperature correction is therefore estimated to be 1.12%.

A1-5.1.1.3 Rotary positive displacement meters

This meter type is not considered in the Competent Authority Guidelines[4] for gas flows but this class of device is used extensively in the gas industry and is similar, in principle, to the Ovalrad meter[4] that is listed in the Guidelines for liquid flows. The metering uncertainty is better than 0.5%. The Dresser Roots meter is a typical example that meets this uncertainty specification as shown below:



Source: Four Inch 23M232 ROOTS® Meter Technical Brochure (max flow 650 m^3/h)

Conservatively, the meter uncertainty is assumed not to contain the uncertainty related to pressure and temperature corrections which is assumed, again, to be of the order of 0.5%, giving an overall uncertainty of 0.71%.

A1-5.1.2 Off-site metering

Reporting may be based on metering facilities operated by the Gas Supplier or the Public Gas Transporter. In these situations, the meter must be complaint with IGE/GM/4, 1996 and the Ofgem Code of Practice COP1c, 1996 and will conform, as a minimum, to the uncertainty specifications detailed above. The supplier's metering may also be subject to the DTI guidelines for custody transfers within the petroleum industry, as described in the main text. These guidelines specify that mass flow measurement should be within an overall uncertainty of ±1%.

A1-5.2 GAS STATIONS – EMISSION FACTOR

A1-5.2.1 On-site analysis

The emission factor is often based on natural gas composition, measured using a process chromatograph calibrated by an ISO17025 accredited laboratory.

The uncertainties in the basic physical properties of the gas components and the calculation methods are lower than ±0.05% and can therefore be neglected (ISO 6976: 1995). The uncertainty in the fuel gas analysis depends on the individual gas components and the concentrations of those components.

Sampling is typically undertaken on a 4 minute cycle, producing more than 130,000 individual spot sample results across the reporting year. The relevant daily average gas properties are flow weighted to give the period reporting average.

The table below lists the measured components of natural gas and gives a typical calibration gas composition. This is a traceable calibration gas supplied by an accredited laboratory and has a typical expanded uncertainty (U_{95}), given below for each gas component. These expanded uncertainties are converted to standard, relative uncertainties (U_σ) and combined, in the usual way, to give a combined compositional standard uncertainty of about 0.05%.

Since higher hydrocarbons yield an increased number of moles of CO_2 per mole of parent fuel gas, as shown in the table, the relative uncertainties in emission factor are therefore increased. For the example shown, the standard uncertainty in emission factor, due to calibration gas uncertainty, is about 0.06% and the expanded uncertainty is therefore 0.12%.

A detailed uncertainty assessment of a given chromatograph is normally undertaken by the accredited laboratory[7]. This generally takes the form of:

- a bias determination of individual fuel gas components using a matrix of traceable test gases (according to ISO 10723:1995 Natural gas- Performance evaluation of on-line analytical systems);
- a repeatability determination for each fuel gas component determined from multiple injections of the test gases.

Component			Calibration Gas					
		MM		U_{95}	U_σ	$MolCO_2/Mol_i$	EF	U_σ
#	I	kg/kmol	% mol	%mol	%R	-	tCO_2/km^3	%R
1	CH_4	16.043	80.5	0.090	0.056	1	1.861	0.056
2	C_2H_6	30.07	7.0	0.028	0.200	2	3.722	0.400
3	C_3H_8	44.097	3.3	0.014	0.212	3	5.584	0.636
4	n-C_4H_{10}	58.123	0.5	0.003	0.310	4	7.445	1.240
5	i-C_4H_{10}	58.123	0.5	0.003	0.280	4	7.445	1.120
6	n-C_5H_{12}	72.15	0.1	0.001	0.650	5	9.306	3.250
7	i-C_5H_{12}	72.15	0.1	0.001	0.550	5	9.306	2.750
8	neo-C_5H_{12}	72.15	0.1	0.002	0.950	5	9.306	4.750
9	n-C_6H_{14}	86.177	0.1	0.003	1.350	6	11.167	8.100
10	CO_2	44.01	3.3	0.014	0.212	1	1.861	0.212
11	N_2	28.0135	4.5	0.021	0.233	0	0.000	0.000
	Total		**100.0**		**0.049**		**2.118**	**0.059**

Typical Calibration Gas Composition and Uncertainties

The bias and repeatability depend, to some extent, on the composition of the natural gas, i.e., the relative proportions of the different fuel gas components. An estimate of the global uncertainty, taking account of any likely deviations in natural gas composition, can be obtained using Monte-Carlo simulations in which results are generated for a large number of simulated compositions[7]. The consequent impacts

[7] (Squire, G. (EffecTech), 'Winnington CHP. Fuel Gas Quality Measurement System. ISO 17025 accredited calibration report for fiscal purposes and EU/ETS compliance', prepared for E.ON UK CHP Ltd., Sep 2006.

on physical properties (CV, density and Wobbe number) can then be calculated, based on ISO 6976 (ISO 6976:1995 *Natural gas- Calculation of calorific value, density and Wobbe index from composition*).

Combining bias and random errors is not a straightforward procedure [ISO 15796] but since the number of samples is very large, it can be assumed that the repeatability component of the uncertainty is negligibly small in the long term average. Typically, for a gas chromatograph that is complaint with the CV uncertainty requirements (see below), the compositional standard uncertainty in average emission factor is therefore of the order of 0.1 %, i.e., not more than twice the calibration gas uncertainty. This implies that the long term average bias in the measurements is also very low.

A conservative estimate of 0.2% expanded uncertainty is therefore assumed for a good quality chromatographs calibrated by an accredited laboratory[7].

A1-5.2.2 Off-site analysis

Reporting may be based on billed average properties based on chromatographs operated by the Gas Supplier or the Public Gas Transporter. In these situations, the supplier's information should be to a similar level of uncertainty as that quoted above for a Danalyser chromatograph situated at a CHP site (0.2%).

A1-5.2.3 Assumed Emission Factor

For a Tier 2a approach, the emission factor can be taken from DEFRA's recommended Local Distribution Zone (LDZ) tabulation. An uncertainty analysis is therefore not required.

A1-5.3 GAS STATIONS – OXIDATION FACTOR

An oxidation factor of 1.0 is specified in the Phase II M&R Guidelines and National Inventory returns. An uncertainty analysis is therefore not required.

A1-5.4 GAS STATIONS – CALORIFIC VALUE

A1-5.4.1 Uncertainty in GCV and NCV

The absolute maximum permissible bias error on gross calorific value for a fiscal/custody transfer metering point in the UK is 0.1 MJ/m^3. A detailed uncertainty assessment of a given chromatograph is normally undertaken by an accredited laboratory as described above. It is possible to obtain bias errors below 0.04 MJ/m^3 but, as a conservative assumption, the 0.1 MJ/m^3 limit is combined with the lowest anticipated value of GCV (36.9 MJ/m^3)[8] to give an expanded uncertainty of 0.27%.

Since NCV is a reporting item only under the JEP Methodology, the uncertainty of conversion of GCV to NCV is not considered since it is acceptable, for natural gas, to use a standard multiplication factor of 0.9 when correcting from GCV to NCV. However, the NCV can be obtained directly from the chromatograph, having applied a full correction according to ISO 6976 (ISO 6976:1995, *Natural gas – Calculation of calorific values, density, relative density and Wobbe index from composition*). In

[8] Gas Transportation Ten Year Statement 2006, National Grid

these cases, the uncertainty may be quoted in the calibration report. The expanded uncertainty is of the same order as that for the GCV, i.e., circa 0.3%.

A1-5.4.2 Assumed NCV

For a Tier 2 approach, the NCV can be taken from DEFRA's recommended Local Distribution Zone (LDZ) tabulation. An uncertainty analysis is therefore not required.

Appendix 2: Comparison of Ultimate Analysis and Parr Carbon Determinations

1. Coal Analysis
    1.1 Direct Determination
    1.2 Indirect Determination
2. Recommendation

A2-1 Coal Analysis

Coal parameters which are determined on a routine basis are Gross Calorific Value (GCV), moisture, ash, volatile matter, sulphur and chlorine. The above list of parameters is known generally as the Proximate Analysis. Carbon, hydrogen and nitrogen are not routinely determined; these three analytes are known as the Ultimate Analysis. Coal parameters will often be quoted on a 'dry ash free' (DAF) basis. This means that the particular parameter has been normalised for the ash and moisture contents (the 'inert content') of the coal and allows the coal matter to be compared on a like for like basis.

For CO_2 reporting, carbon content of the fuel is required. There are two methods of achieving this.

A2-1.1 Direct Determination

Carbon in coal has traditionally been determined to BS1016-6 (1977) although the more recent standard ASTM D5373-93 covers modern automatic analyses. Both methods involve combustion of the coal and determination of the quantity of produced carbon dioxide.

As noted above, direct determination of carbon in coal on a routine basis is not generally undertaken. If carbon analysis was required on every coal sample it would approximately double the current proximate analysis cost and is not judged to be a necessary or cost-effective solution.

An alternative is to undertake limited carbon determinations. Generally, the dry ash free (DAF) carbon content of a given rank of coal lies within a fairly tight band – the coals delivered to the majority of UK power stations typically have DAF carbon contents of between 80-85%. Experience shows that for a single coal, the DAF carbon content is unlikely to change over time significantly and application of a constant value is appropriate. Note that the moisture and ash contents of coals will vary and so the constant DAF carbon content must be converted back to the as received carbon content using the actual moisture and ash contents.

A2-1.2 Indirect Determination

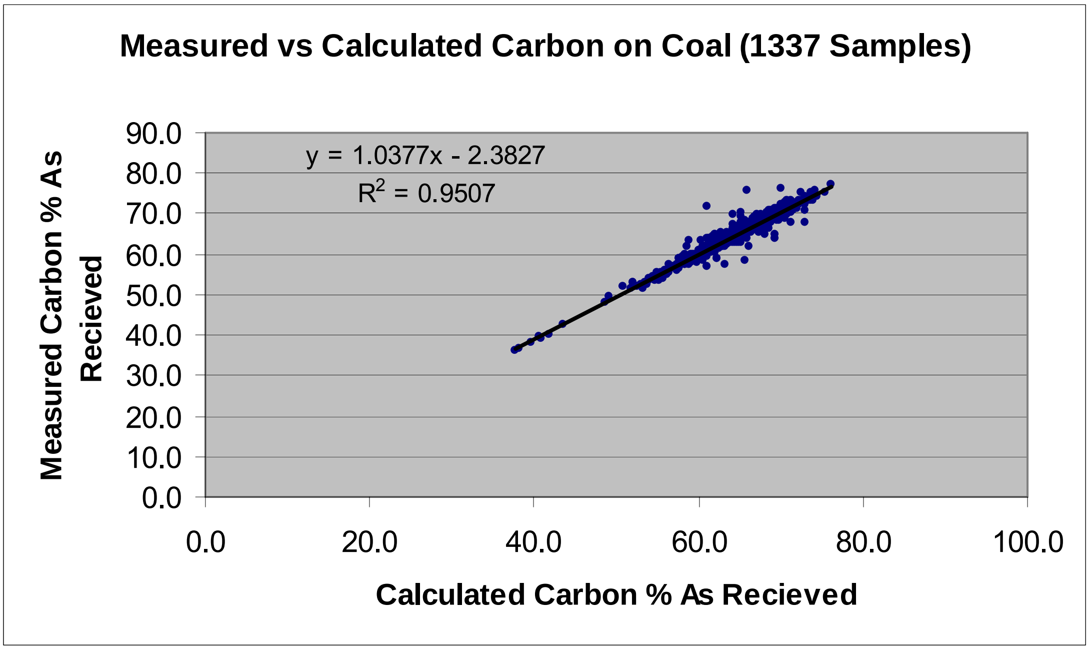
Over the many years that coal science has been studied, a number of close correlations have been determined between coal quality parameters. There are many formulae (e.g. Dulong, Parr) that have been developed to link such parameters to one another. A good example of the use of such formulae is the derivation of Net Calorific Value (NCV) of a coal. This process uses a formula for deriving the hydrogen content of the coal, the result from which is input for another formula which determines the NCV from the GCV taking into account the hydrogen and moisture contents. It should be noted that as coal is purchased on the basis of NCV, these equations are accepted internationally as valid and robust.
The Parr formulae has been used by the CEGB and subsequent companies for many years and relates carbon content of coal to a combination of NCV, moisture, volatile matter, ash and sulphur. The formula is shown below:

% Carbon (A/R) = ((1.6373 x NCV x 0.001) – (0.3264 x H2O) – (0.2003 x VM (A/R)) – (0.3255 x Ash (A/R)) – (0.5215 x S (A/R)) + 36.6844

Note: VM – volatile matter
S – sulphur
A/R – as received basis

This relationship has been used within the Electricity supply industry's Fuel Management System at each power station to determine a monthly average carbon content of the coal burnt.

As noted above, compared to standard proximate analysis, there are limited data available for measured carbon in coals. However, the plot below shows the relationship between measured carbon and calculated carbon for 1337 coal samples measured on coals from 10 countries analysed at three laboratories. This illustrates the good agreement between the two parameters and confirms the validity of the equation. Note the vast majority of coals used by the UK electricity supply industry will contain between 60 and 70% carbon (as received).



The uncertainty in carbon measurement is discussed in Appendix A1-3.2.4, where the uncertainty in a single determination of carbon by ultimate analysis was estimated as 2.51% based on the reproducibility stated in the standard. The uncertainty in the Parr calculation cannot be estimated directly but was assessed by considering the differences between the measured carbon and calculated carbon. The uncertainty in the difference between a single pair of data points based on the 1337 pairs of data was found to be 1.6 % carbon absolute. This approach removes the uncertainty contribution from the sampling, moisture content and ash content since each pair derives from an identical sample. Assuming a typical coal carbon content of 65% this would correspond to an uncertainty of 2.4%. The uncertainty in the difference between two determinations would be expected to be higher than that of a single determination, hence it follows that the uncertainty derived from the dataset is lower than the conservative assumption made in Appendix 1. It also follows that the uncertainty inherent in the Parr calculation is comparable with that of the ultimate analysis and is certainly no more than the value assumed to determine the frequency of sampling. Hence the sampling procedure defined in A1-2.1 can apply to calculated carbon as well, that is undertaking carbon analysis on a monthly composite for UK coals and each boatload for imported coals ensuring that a minimum of 72 samples are analysed per year.

A2-2 Recommendation

It is recommended that the Parr formula, unchanged from that inherited from the CEGB, is accepted as a valid way of determining carbon in coal for EUETS monitoring and reporting, but that Generators who wish to used as-analysed carbon figures, meeting the EUETS QA standards, may continue to do so. The uncertainties in the Parr determinations are no more than that of the measured carbon repeatability and so the sampling frequencies defined in A1-2.1 are appropriate.